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ABSTRACT

Accurate evaluation of pore systems in shale reservoirs is critical for understanding fluid flow, gas storage capacity, and overall reservoir performance. Extensive research has been conducted on the micro- and nano-pore structure of shale reservoirs using various experimental methods and shale samples. However, discrepancies in sample preparation standards and experimental parameters—such as observation techniques and data interpretation—raise concerns about the reliability and comparability of these results across different shale reservoirs. This review systematically evaluates the current methods for characterizing shale pore systems, with particular emphasis on commonly used techniques such as scanning electron microscopy (SEM), gas adsorption, and CT scanning. Key challenges related to sample preparation (e.g., sample size) and experimental conditions (e.g., voltage and current) are discussed, as these factors can introduce significant inaccuracies into pore structure characterization, even for well-established methods. Additionally, we examine the difficulties in integrating these methods to achieve a comprehensive understanding of shale pore parameters, including the quantification of organic and inorganic porosity, full-scale pore size distribution, and pore connectivity. Addressing these challenges requires the establishment of standardized processing workflows to enhance the comparability of results and minimize experimental errors. We also highlight often-overlooked issues, such as the potential discrepancy between pore structures observed under laboratory conditions and those at in-situ depths. The review concludes with recommendations for future research, including the development of advanced experimental techniques and more efficient data processing strategies to improve pore characterization in shale reservoirs. This review provides a new perspective for future research and addresses a critical gap in understanding the impact of experimental conditions on pore structure characterization outcomes.

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## 1. Introduction

The global economic expansion and the resulting surge in energy demand have exacerbated the conflict between supply and demand. Unconventional energy resources, such as shale oil and shale gas, are crucial alternatives to conventional sources and have garnered significant attention. Over the past decade, the development and utilization of hydrocarbons from shale systems have expanded considerably. Shale gas resources, in particular, hold significant promise, with technically recoverable resources estimated at $2.1 \times 10^5$ bcm (Zou et al., 2023). Researchers worldwide generally agree that accelerating the utilization of shale gas is a key strategy to address the energy gap (Arif et al., 2021; Bera and Shah, 2021; Cai et al., 2024).

Shales serve as self-generating and self-storing reservoir systems (Hao and Zou, 2013; Katz and Arango, 2018). Hydrocarbons are primarily stored in ultra-fine pores and micro-fractures, existing in both free and adsorbed states (Slatt and O'Brien, 2011; Loucks et al., 2012; Löhr et al., 2015; Arif et al., 2021). The pore structure influences shale gas occurrence, with free gas

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### 4.4. Observation conditions for FE-SEM

Scanning electron microscopy (SEM) is a key experimental technique for shale reservoir characterization. While it offers significant opportunities, it also presents several challenges. In addition to ion milling, experimental observation conditions—such as acceleration voltage, current, and dwell time of the electron beam—pose further challenges (Wang et al., 2015b; Zhao et al., 2019).

Acceleration voltage refers to the potential difference between the anode and cathode of the electron gun, which determines the energy of the incident electron beam. This, in turn, affects the penetration depth of the electrons (Hua et al., 2014). A higher acceleration voltage increases electron energy, leading to deeper penetration into the sample surface (Imbraguglio et al., 2012; Tomkus et al., 2020). While this can reduce surface contamination and facilitate the observation of internal characteristics, it may also cause negative effects, such as the loss of microstructural details on the sample surface (Fig. 10(a)–(d)).

Generally, the incident electron current ($I_p$) in SEM is typically the sum of the backscattered electron current ($\eta I_b$), secondary electron current ($\delta I_b$), and ground current ($I_{sc}$) (Hua et al., 2014; Wang et al., 2015b). When the sum of the secondary electron yield ($\delta$; n2 2 [(; -38.5 (:)]f (32163 0 0101.2 (17 017 71(-)51500r16)-o9j /3167

effects cause excess electrons to be discharged, forcing $\delta + \eta$ to approach 1 (Wang et al., 2015b; Song et al., 2021). However, when the voltage is $<V_1$ or $>V_2$ (i.e., $\delta + \eta < 1$), large charges will accumulate on the sample surface, producing charging effects (Fig. 11). This can distort the sample information (Tomkus et al., 2020). In practice, both current and voltage are adjusted during SEM observation. Increasing the current improves resolution but also leads to charge accumulation and potential loss of information (Fig. 10(a)–(d)). Zhao et al. (2019) suggested that a voltage <10 kV and a current <170 pA are optimal for pore characterization and subsequent post-processing analysis (e.g., OM surface porosity statistics, Song et al., 2019; Xu et al., 2020a). Additionally, extending the scanning time can improve the signal-to-noise ratio and image quality. However, this also increases the dwell time of the electron beam, risking image distortion and high-brightness tailing (Fig. 10(e) and (f)). It is important to note that although this charge accumulation may not be ideal for image analysis, it can have specific applications, such as revealing the distribution of residual oil in reservoirs (Wang et al., 2015b).

As discussed, these three factors—voltage, current, and dwell time—jointly control the quality of SEM images, which in turn affects the extraction and interpretation of pore characteristics (Klaver et al., 2012; Gou et al., 2019; Chandra and Vishal, 2021). Excessive experimental conditions can cause significant electron bombardment, leading to sample heating, similar to ion polishing, and altering the pore structure (Imbraguglio et al., 2012; Tomkus et al., 2020). This phenomenon has also been observed in our SEM image analyses. Therefore, selecting appropriate conditions is crucial for obtaining accurate shale pore information. We recommend starting with a moderate acceleration voltage (e.g., 3–5 kV) and adjusting the parameters based on the specific sample characteristics. Lower voltage, current, and dwell time are more suitable for samples with a high matrix mineral content. For samples with higher clay or organic matter content, these parameters may be increased to achieve a more comprehensive and accurate understanding of the pore structure. For example, the samples shown in Fig. 9(d) and (f) are shale with approximately 60% felsic minerals and a TOC of about 3%. For these samples, we used a voltage of

**Fig. 10.** Influence of voltage, current, and residence time on quality of SEM images. **(a)–(d)** are modified from Zhao et al. (2019), **(e)–(f)** are modified from Wang et al. (2015b).

**Fig. 11.** Generation mechanism of charging in sample surface, modified from Hua et al. (2014) and Wang et al. (2015b). $\eta$: backscattered electron (BSE) yield; $\delta$: secondary electron (SE) yield.

3 kV, a current of 0.4 nA, and a dwell time of 30 μs, resulting in excellent imaging (Fig. 9(d), (f)). In contrast, for samples with a higher clay mineral content, we found that adjusting the voltage to 5 kV could achieve an imaging effect similar to the one above. However, it is important to note that this conclusion is preliminary, based on a limited number of tests conducted during our work. In SEM detection, several factors, including the type of instrument, whether the sample is coated with carbon or gold, the degree of sample drying, and the hydrocarbon content, all influence the optimal parameter settings.

### 4.5. Three-dimensional imaging

Following the acquisition of 2D greyscale images by CT scanning, these images are superimposed to produce a 3D data volume (Wu et al., 2019, 2020b). In a CT scan image, the gray value represents the density of the substance. Transitioning from black to white signifies a density shift from low to high (Gou et al., 2019). Substances with higher density (e.g., pyrite) appear brighter in the CT image. Pores and micro-fractures appear nearly black or with lower gray values (Wang et al., 2016). This allows for the analysis of pore structure by interpreting color variations in the image. Filters are vitally necessary to apply to original images to reduce noise and chromatic aberration, making pore phases more visible (Ma et al., 2017; Chandra and Vishal, 2021). There are many filters that can be used for shale images, and their filtering effects differ significantly (Buades et al., 2006; Saif et al., 2017). The filtering effects of various filters on a noisy image are compared and shown in Fig. 12. The non-local-means filter compares the geometric configurations of pixels within the same component, utilizing the self-similarity of images across various locations. It derives the final imaging data through pixel-weighted averaging, demonstrating notable effectiveness in segmenting shale reservoirs with diverse mineral compositions (Buades et al., 2006; Gou et al., 2019). Therefore, the noise removed by the non-local-means filter is more noticeable (Fig. 12(a1)–(a4)). However, with the increase in filtering times, small pore information is gradually removed (Fig. 12(a4)). The anisotropic diffusion filter emphasizes the retention of straight edges (Buades et al., 2006), and thus the noise removal effect is relatively weak (Fig. 12(b1)–(b4)). When the delineate filter is applied to the raw image, noise and multiphase component information in shale are depicted simultaneously (Ma et al., 2017; Saif et al., 2017). The superposition of artifacts makes it difficult to extract useful information (Fig. 12(c1)–(c4)). The Gaussian filter method blurs pixels to remove noise, and a 2D convolution operator is performed during this process (Buades et al., 2006; Chandra and Vishal, 2021). Overall, the slice after the third filtering is almost unchanged from the original slice (Fig. 12(d1)–(d4)). The box filter uses deconvolution to extract material phases from high-noise images (López et al., 2022). While the noise is removed, the virtual shadow caused by the loss of potential dependencies between estimated components becomes gradually obvious (Fig. 12(e1)–(e4)). Apart from these, the median filter and edge-preserving smoothing filter are also commonly mentioned (Buades et al., 2006; Ma et al., 2017; Chandra and Vishal, 2021). Each method provides reasonable solutions, but none is perfect. Applying a combination of these filters on a case-by-case basis may be an effective way to minimize noise and retain useful information. This is a task that requires long-term attempts and improvements by scholars.

During the operation of FIB-SEM, the ion beam mills and polishes the surface of the sample, while the electron beam is used for imaging (Curtis et al., 2012b; Fitschen et al., 2017). However, due to different sputtering rates of the ion beam and incomplete milling of the material, the resulting images often possess a curtaining effect, i.e., bright stripe-like artifacts (Fig. 13). There are two ways to deal with this problem. One is to use a lower beam current, which leads to impractical processing times and increased costs. The other is to discard this part of the images, which may compromise representativeness. Currently, the Fast Fourier Transform (FFT) filter in Avizo (https://www.fei.com/software/avizo3d/) is a simple method to remove the curtain effect (Schankula et al., 2018; Mahmoud et al., 2023). The results presented in our work are also very effective (Fig. 13). In light of this, we further analyzed the pore characteristics of the images before and after removing the curtaining effect. As shown in Fig. 13, all images were processed according to a standardized procedure. However, the proportion of pore development in the image without removing the curtaining effect was significantly higher. This discrepancy arises because the artifacts caused by the curtaining effect were included in the analysis, leading to increased error. Therefore, effectively removing the curtaining artifacts in SEM images is crucial for constructing the three-dimensional dataset for FIB-SEM and accurately capturing its internal pore information. It is worth noting that Fourier-based filtering, moment matching, and histogram-based methods have

**Fig. 13.** An example of using the FFT model to remove the curtain effect from FIB-SEM images **(a1)–(d1)** and to eliminate its influence on the pore statistics results **(a2)–(d2)**. The red area represents the pores delineated using a unified standard. The pore area ratio refers to the proportion of the red area relative to the total area of the image.

also been suggested in the relevant literature (Chen and Pellequer, 2011; Fitschen et al., 2017). The ultimate goal is to obtain high-quality images and accurately evaluate the characteristics of shale reservoirs.

## 5. Prospects and challenges: pore structure fine characterization

### *5.1. Quantitation of reservoir space for different types*

From the perspective of pore types, the reservoir space in shale can be broadly classified into two categories: inorganic and organic pores. Inorganic pores include interP pores, intraP pores, and fracture-related pores (Fig. 2), and they serve as key reservoir spaces for free gas (Gou and Xu, 2019). The internal surface area of OM pores is significantly higher than that of inorganic pores, providing more adsorption sites, which facilitates the storage of adsorbed gas (Bernard et al., 2013; Hao et al., 2013). Furthermore, if the number of organic pores is sufficiently high and their sizes are large enough, substantial amounts of free gas can also be stored in the central regions of the pores after gas adsorption is completed (Jin et al., 2021; Abolghasemi and Andersen, 2022; Cai et al., 2024; Wu et al., 2024). Due to the more complex pore network in OM pores, gas flow within them is relatively restricted (Hu et al., 2015; Cai et al., 2024). Therefore, clearly distinguishing and evaluating the content of OM and inorganic pores not only enhances the accuracy of reservoir assessments but also guides exploitation and engineering applications, ultimately improving the development efficiency and economic benefits of shale gas.

The fitting slope method is a widely used and efficient approach for calculating organic and inorganic porosity (Ma et al., 2016; Chen et al., 2019). This method relies on the strong positive correlation between TOC content and porosity. In general, inorganic

porosity is estimated as the intercept when the TOC content is zero, based on the linear relationship (Fig. 14(a) and (b)). Given this, organic porosity can be calculated by subtracting the inorganic porosity from the total measured porosity. However, we observed that the measured porosity at some points is lower than the estimated inorganic porosity (Fig. 14(a) and (b)), suggesting that the validity of the assessed results may be overly optimistic, at least for these points. Furthermore, two additional limitations should be noted. First, the evaluation results are highly dependent on the number of data points. Changes in the number of data points can alter the linear relationship, thereby affecting the porosity results. Second, there may be no clear relationship between TOC and porosity in highly deformed areas (Xu et al., 2020a; Gou et al., 2021) or in regions with limited thermal maturity (Dong and Harris, 2020), rendering this method inapplicable. Overall, the porosity of both organic and inorganic pores evaluated by this method is constrained by factors such as the amount of data and the degree of correlation between TOC and porosity. Consequently, although this method is relatively simple, the calculated results often exhibit considerable errors.

Using the mass balance principle, Wang et al. (2014) developed a petrophysical model to quantitatively analyze the components of shale porosity (Fig. 14(c)). In this model, shale pore spaces are categorized into pores associated with brittle minerals, pores related to clay minerals, and organic pores. The porosity of a shale reservoir can then be expressed using Equation (1). In principle, this model provides a reliable method for evaluating porosity characteristics and has been widely applied in the literature (Gou et al., 2020; Shu et al., 2020). However, subsequent studies have highlighted that the influence of mineralogy and TOC on shale pore space is far more complex, involving interactions between organic matter and inorganic minerals (İnan et al., 2018; Katz and Arango, 2018). Therefore, this model is more applicable to shales in the middle and late diagenetic stages, where the pore system is relatively stable. It is also important to note that the calculated organic porosity values for argillaceous shales may be overestimated, as the model was developed for organic-rich shales (TOC >2%) (Wang et al., 2014). Nonetheless, the method has been widely used for the quantitative analysis of various types of porosity in shale gas reservoirs, particularly in the complex regions of southern China (Wang et al., 2014; Gou et al., 2020; Shu et al., 2020). This suggests that the model may be one of the most accurate and practical approaches available.

$$\Phi = \rho \times A_{\mathrm{Bri}} \times V_{\mathrm{Bri}} + \rho \times A_{\mathrm{Clay}} \times V_{\mathrm{Clay}} + \rho \times A_{\mathrm{TOC}} \times V_{\mathrm{TOC}} \quad (1)$$

where $\Phi$ is the porosity of the shale sample, %; $\rho$ is the bulk density of the shale sample, g/cm$^3$; $A_{\mathrm{Bri}}$, $A_{\mathrm{Clay}}$, and $A_{\mathrm{TOC}}$ are the mass fractions of brittle mineral, clay, and organic matter, respectively, %; $V_{\mathrm{Bri}}$, $V_{\mathrm{Clay}}$, and $V_{\mathrm{TOC}}$ are the pore volume of per unit mass of brittle mineral, clay, and organic matter, respectively, cm$^3$/g.

**Fig. 14.** Evaluation of organic and inorganic porosity with different methods. **(a)–(b)** are calculated by the relationship between TOC and shale total porosity, modified from Ma et al. (2016) and Shu et al. (2020); **(c)** is calculated by a rock physical model, modified from Wang et al. (2014); **(d)** is calculated by an NMR spectrum, modified from Gannaway (2014).

Nuclear magnetic resonance (NMR) has also been employed to characterize the porosity components of shale (Fig. 14(d)) (Gannaway, 2014; Yao and Liu, 2018). Tinni et al. (2014b) demonstrated that brine can infiltrate both organic and inorganic pore systems at pressures below 7000 psia, whereas dodecane fails to penetrate clay pores even at higher pressures. Gannaway (2014) further confirmed that dodecane enters only the organic pores. Since inorganic pores are water-wettable, water-saturated samples typically exhibit strong NMR $T_2$ spectrum signals in these pores (Sulucarnain et al., 2012; Lai et al., 2018). The distinct contrast between various $T_2$ spectra ultimately enables the quantification of porosity partitioning in shales (Fig. 14(d)) (Sulucarnain et al., 2012; Gannaway, 2014; Tinni et al., 2014b). As noted earlier, shale saturation with water can alter the pore structure due to expansion, which impacts the accuracy of the results (Sun et al., 2020a; Jiang et al., 2023). Moreover, NMR testing parameters—such as waiting time, echo time, and the number of echoes—directly influence the accuracy and reliability of reservoir characteristics, including porosity and pore size distribution. Different lithologies require distinct testing parameters (Zhang et al., 2018a; Song and Kausik, 2019; Bai et al., 2023). However, these parameters vary significantly across different testing processes, and no standardized approach has been established. The determination of organic and inorganic pore porosity through NMR remains subject to significant uncertainty, and the associated methods and parameters require further refinement.

In addition to the aforementioned methods, porosity partitioning between organic and inorganic pores can be quantified by processing 2D SEM images (Loucks et al., 2009; Milliken et al., 2013; Song et al., 2019). The core of this method lies in the statistical analysis of organic pores in 2D images. However, the resolution limit of SEM (~2 nm) and inherent statistical errors (Chandra and Vishal, 2021) may sometimes yield inconclusive results. Resolution also poses a challenge when differentiating organic and inorganic pores using 3D imaging techniques (Gou et al., 2019; Arif et al., 2021). Additionally, some researchers have proposed using logging data (Zhang et al., 2019) and geochemical parameters (Zhang et al., 2021) to quantify organic and inorganic pores. However, many parameters in these models are difficult to accurately determine. In summary, while numerous methods exist to quantify porosity partitioning in shales, all of them involve multiple variables. These factors increase the potential uncontrollability of calculation errors and limit their applicability.

### 5.2. Full-scale analysis of pore space

The integrated characterization of shale pore structure is crucial for assessing shale enrichment and improving reservoir prediction (Curtis, 2010; Slatt and O'Brien, 2011; Loucks et al., 2012; Hao et al., 2013; Arif et al., 2021). However, the highly anisotropic nature and varied pore sizes of shale complicate accurate quantification (Loucks et al., 2012; Mastalerz et al., 2013; Anovitz and Cole, 2015; Xu et al., 2020a, 2020b). Existing techniques still have notable limitations when used independently (Fig. 1). While challenging, multiscale characterization allows for the identification of overlapping areas between two or more techniques (Fig. 15(a)). Therefore, the combined use of multiscale correlative techniques is widely recognized as an effective solution to this issue (Schmitt et al., 2013; Gou et al., 2019; Wang et al., 2019b; Zhang et al., 2020; Arif et al., 2021; Chandra and Vishal, 2021; Iqbal et al., 2021; Lei et al., 2021).

In recent years, the integration of $CO_2$ adsorption, $N_2$ adsorption, and MICP has become a widely adopted method for assessing full-scale pore characteristics of shale reservoirs (Fig. 15(b)) (Schmitt et al., 2013; Jiang et al., 2016; Wang et al., 2019b; Zhang et al., 2020; Iqbal et al., 2021). These studies suggest that shale pore volume is primarily attributed to micropores and mesopores, while macropores and micro-fractures contribute less. However, as mentioned earlier, new micro-fractures and pore damage can occur in highly brittle shale samples during Hg injection at high pressure (Wang et al., 2019a; Sun et al., 2020b). In such cases, Zhu et al. (2016) and Gou et al. (2019) proposed a novel approach that combines gas adsorption with CT scanning (Fig. 15(c)). They demonstrated that the volume proportion of macropores and micro-fractures is comparable to that of micropores or mesopores. The contribution of μm-scale pores to permeability is dominant (Gou et al., 2019). Moreover, imaging technologies enable the evaluation of gas molecule flow mechanisms based on pore distribution (Arif et al., 2021; Chandra and Vishal, 2021).

While these techniques must be integrated to comprehensively describe shale pore spaces and micro-fracture networks, significant challenges remain in combining multiple approaches. For example, there is debate regarding the splicing point of $N_2$ adsorption and MICP data: should it be 6 nm (Wang et al., 2021), 10 nm (Cao et al., 2016), 50 nm (Jiang et al., 2016; Tang et al., 2016; Wang et al., 2019b; Iqbal et al., 2021), 65 nm (Wang et al., 2019a), 80 nm (Li et al., 2017), or 100 nm (Wang et al., 2015a)? Schmitt et al. (2013) proposed that the connection point should be selected where the variation in pore volume observed by the two techniques is equal. However, such instances are rare (Wang et al., 2019b). Instead, connections are usually established through fixed-

**Fig. 15.** **(a)** Principle of full-scale pore size distribution using a combination of various methods; **(b)** illustrates the pore size characterization combining $CO_2$ adsorption, $N_2$ adsorption, and MICP, modified from Wang et al. (2019b). However, significant discrepancies are evident between the different methods; **(c)** presents the pore size characterization using $CO_2$ adsorption, $N_2$ adsorption, nano-CT, and micro-CT, modified from Gou et al. (2019).

point splicing (Li et al., 2017; Wang et al., 2019a; Iqbal et al., 2021). The primary drawback of this method is that the integrated pore volume distribution curve becomes discontinuous, resulting in significant jumps or clear inflection points at the connection (Fig. 15(b)). This raises concerns about the accuracy of the integrated pore volume distribution. Similar issues may arise with other splicing methods. Overall, full-scale pore and micro-fracture characterization remains a crucial direction in shale reservoir evaluation, and appropriate splicing is essential for this technology. To ensure accuracy, integrated results must be verified with additional analytical test data, such as He-porosity (Zhu et al., 2016; Gou et al., 2019).

### 5.3. Investigation of pore connectivity

The production of shale gas involves the migration of hydrocarbons from the matrix to hydraulic fractures, a process controlled by the connectivity of μm- and nm-sized pores (Sun et al., 2020b; Gou et al., 2021). Pore connectivity significantly influences the ultimate recovery from shale reservoirs (Hu et al., 2015). Various laboratory techniques, including MICP, spontaneous imbibition, saturated diffusion, SANS, and 3D-CT scanning, have been developed to characterize pore connectivity in shale reservoirs (Clarkson et al., 2013; Yang et al., 2018; Gou et al., 2019; Sun et al., 2020b; Zhao et al., 2020; Zhou et al., 2024b).

MICP was repeated on the same samples to assess pore connectivity by analyzing the residual distribution of mercury across different pore size intervals (Fig. 16(a)). The results show significantly less mercury entering pores smaller than ~13 nm during the second injection. Based on these findings, Sun et al. (2020b) concluded that pores smaller than 13 nm have poor connectivity, suggesting that these pores may serve as storage spaces but exhibit poor flow properties. Additionally, residual mercury was observed in some μm-scale pores, though the cause of this phenomenon remains unclear.

Spontaneous fluid imbibition characteristics are closely linked to the pore connectivity of shale. Deionized (DI) water and *n*-decane are commonly used as intrusion fluids (Hu et al., 2015; Yang et al., 2018; Gao et al., 2019). Pore connectivity is generally categorized into three types: high connectivity (imbibition slope >0.5), intermediate connectivity (slope between 0.26 and 0.5), and poor connectivity (slope <0.26) (Hu et al., 2015; Zhou et al., 2024a). As shown in Fig. 16(b), the slopes decrease as the intrusive fluid migrates from larger to smaller pores, indicating that larger pores have better connectivity (Yang et al., 2018; Gao et al., 2019). Overall, the slopes for *n*-decane are consistently higher than those for DI water, indicating that hydrocarbon-filled pores have greater connectivity. The difference in slopes between the two fluids also reflects differences in pore wettability (Hu et al., 2015; Gao et al., 2019; Zhou et al., 2024a).

Tracer diffusion in brine-saturated shale samples can reflect pore connectivity through the distribution of elements (Fig. 16(c)). There is a positive correlation between element concentration and pore connectivity (Sun et al., 2020b; Zhao et al., 2020). However, the phenomenon of “wall migration” can result in elevated ion concentrations at the sample boundary, potentially leading to misinterpretations (Sun et al., 2020a). While the connectivity assessed by this method provides valuable insights, it lacks quantitative data. Additionally, the interaction between the solution and shales containing high clay content remains unclear, as does the extent of this interaction. These concerns also apply to spontaneous fluid imbibition experiments.

SAS techniques can be used to evaluate pore connectivity by comparing pore size distributions derived from gas intrusion and scattering techniques (Fig. 16(d)). Sun et al. (2020b) obtained pore characteristics from $N_2$ adsorption and SANS for the same powdered sample (35–80 mesh). In general, gas adsorption is mainly used to evaluate connected pores, while SANS can also characterize isolated pores. In their study, isolated pores were primarily distributed in pore sizes of <2.1 nm and >15 nm (Fig. 16(d)). However, the authors did not provide a clear explanation for the higher $N_2$ adsorption than SANS in some intervals (Sun et al., 2020b). Despite this, the development of SAS techniques provides a new approach for studying shale pore structure. The scattering technology model used for accessing pore structure still requires further refinement, as it is in its early stages (Clarkson et al., 2013; Sun et al., 2020a).

By combining the He porosity and NMR porosity of saturated hydrogen-bearing fluids in plunger samples, the connected pore system of shale was further investigated through their ratio

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