A method to evaluate pore structures of fractured tight sandstone reservoirs using borehole electrical image logging

Liang Xiao, Junran Li, Zhiqiang Mao, and Hongyan Yu

ABSTRACT

Fractures are important in improving tight sandstone pore connectivity and fluid flow capacity. However, the contribution of fractures to pore connectivity and fluid flow capability cannot be quantified using current methods. The objective of this study was to develop a method to quantitatively characterize reservoir improvement as a result of fractures. This method was proposed based on the experimental results of 37 core samples recovered from the Upper Triassic Chang 8 tight sandstone in the Jiyuan area of the Ordos Basin, China. The morphological features of the porosity spectra, the mercury injection capillary pressure curves, and the pore-throat radius distributions were analyzed. Accordingly, a method was proposed to construct pseudocapillary pressure (Pc) curves from the porosity spectra to characterize the pore structure of fractured reservoirs and to establish corresponding models based on the classified power function method. In addition, a model was developed to predict fracture formation permeability based on the Swanson parameter. The proposed method and models were applied in field applications, and the estimated results agreed well with the core and drill-stem testing data. Fractured formations contained good pore structure, high permeability, and oil production rate. The relative errors between the model-predicted pore structure evaluation parameters, permeability from Pc curves, and core-derived results are all within ±30.0%. With the integrated study of reservoir pore structure with permeability, the effective Upper Triassic Chang 8 fractured tight sandstone reservoirs with development potential were successfully identified.
INTRODUCTION

The exploration and development of tight oil and gas sandstone reservoirs have become important in China and elsewhere (Zou et al., 2012). Compared with conventional reservoirs, tight sandstones have ultralow porosity (generally <10.0%) and permeability (generally <0.5 md), high irreducible water saturation (ranges from 40.0% to 65.0%), and naturally developed fractures (Holditch, 2006; Zou, 2017). Frequently, intervals with low porosity may yield good production, whereas zones with high porosity may not produce (Newberry et al., 1996; Ghafoori et al., 2009). As a result, reservoir validation prediction faces great challenges for tight sandstones (Fu et al., 2016).

In tight sandstone reservoirs, natural fractures are highly relevant to hydrocarbon accumulation and migration (Ameen et al., 2012; Zeng et al., 2013). Reservoirs with developed fractures generally contain a large pore-throat size and a serried pore network; thus, these reservoirs will have good pore structures and fluid flow capacities (Burberry and Peppers, 2017). In contrast, nonfractured reservoirs tend to have small pore-throat sizes, poor pore structures, and low permeabilities (Santos et al., 2015). Therefore, the validation of tight sandstones is primarily determined by the development of natural fractures (Lyu et al., 2016, 2017). To improve tight sandstone reservoirs identification and validation evaluation, quantitatively characterizing the pore structure and accurately predicting permeability are of great importance.

Borehole electrical image logs are typically used to characterize fracture development (Luthi and Souhaité, 1990; Yamada et al., 2013; Damiani et al., 2016). Using this method, several parameters of fractures, such as fracture porosity, width, length, gaping degree, and density, can be extracted (Ezati et al., 2018). Generally, formations with high fracture porosity, length, width, and density are considered productive (Ghafoori et al., 2009; Xie et al., 2015). However, borehole electrical image logs currently can only be used to macroscopically characterize reservoirs, and the microscopic relationships between fracture parameters and pore structure and permeability cannot be derived (Lai et al., 2017, 2018; Valentin et al., 2018).

Alternatively, formation pore structure may be evaluated using nuclear magnetic resonance (NMR) logs, which measure the induced magnet moment of hydrogen protons contained within the reservoir rocks (Coates et al., 2000; Dunn et al., 2002). In recent years, numerous methods have been developed to evaluate pore structure using NMR logs (Looyestijn, 2001; Volokitin et al., 2001; Ouzzane et al., 2006; Olubunmi and Chike, 2011; Xiao et al., 2016). However, these methods have suffered from a number of limitations in fractured reservoirs. Xiao and Li (2011) pointed out that NMR logs are not effective in pore structure evaluation for fractures with widths less than
2 mm because the fracture angle of dip has no response in NMR logs. In reality, the width of a majority of natural fractures in tight sandstones is less than 2 mm, suggesting that the method based on NMR logs is invalid for these reservoirs (O’Hara et al., 2017; Zhao et al., 2018). Additionally, the shape of the NMR spectrum is strongly affected by hydrocarbons that occupy the pore spaces, which makes it difficult to apply NMR logs to hydrocarbon-bearing formation pore structure evaluation (Mao et al.,

**Figure 1.** Location of the study area in the Ordos Basin (A), location of the Ordos Basin in northeast China (B), and the formation member, thickness, and lithology of the Upper Triassic Yanchang Formation (C) (modified after Dou et al., 2017; Jiang et al., 2018). Fm. = Formation; Mbr. = Member.
Finally, the low longitudinal resolution of NMR logs makes them unsuitable for distinguishing thin sandstones with relative high porosity and permeability (Coates et al., 2000; Dunn et al., 2002). Such formations, however, generally have high hydrocarbon production because of high seepage capability.

Recently, the porosity spectra extracted from borehole electrical image logging have been used to characterize porosity type (primary and secondary porosity) and distribution in carbonate reservoirs (Akbar et al., 2000; Tyagi and Bhaduri, 2002; Wang et al., 2004). A consistency was found between the shape of the porosity spectrum and the production data (Ghafoori et al., 2009; Fu et al., 2016). Despite the known advantages of this method, it can only be used to qualitatively or semiquantitatively characterize fractured reservoirs (Xiao et al., 2016). The parameters associated with pore structure (e.g., pore-throat size and distribution, threshold pressure, median pressure, etc.) cannot be extracted, and the relationship between porosity spectra and permeability cannot be established (Xiao et al., 2016).

The purpose of this paper is to fill out these knowledge gaps and to present a method to quantitatively characterize the fractured reservoir pore structure of tight sandstones based on borehole electrical image logging. In this method, a new model was developed to construct the pseudocapillary pressure \( (P_c) \) curves and the pore-throat radius \( (R_c) \) distribution using the porosity spectrum, based on typical tight sandstones of the Upper Triassic Chang 8 in the Jiyuan area of the Ordos Basin in China. A permeability prediction model, based on the Swanson parameter, was also established to evaluate the permeability of fractured reservoirs.

**GEOLOGICAL SETTINGS**

The Ordos Basin, located in northcentral China, covers an area of more than 370,000 km² (>143,000 mi²) (Shi et al., 2011; Jiang et al., 2018) (Figure 1A, B). The elevation of this flat basin is higher in the east than in the west. The basin consists of six tectonic units: the Yimeng uplift, the Jinxı̂ folding belt, the Yishan slope, the Tianhuang depression, the western edge thrust belt, and the Weibei uplift (Dou et al., 2017; Jiang et al., 2018) (Figure 1A). The Ordos Basin is the second-largest sedimentary basin that formed on the North China craton (Dou et al., 2017). The main oil-bearing reservoirs targeted for exploration and development in this basin include

![Figure 2. Six diagenetic facies of the Upper Triassic Chang 8 in the Jiyuan area, west Ordos Basin, China. These six diagenetic facies contain weak corrosion with chlorite mat (A), corrosion of unstable components (B), tectonic fracture (C), compaction density (D), kaolinite filling (E), and carbonate cementation (F). (A) to (C) are considered constructive diagenetic facies, and (D) to (F) belong to destructive diagenetic facies (modified after Shi et al., 2011).](image-url)
the Upper Triassic Chang 6, Chang 7, and Chang 8 members (Dai et al., 2005). The Jiyuan area lies in the western section of the Ordos Basin, and the Chang 8 member in this area belongs to the Tianhuan depression, a major oil-producing area in the Ordos Basin. The main lithology in Chang 8 includes fine-grained sandstone, siltstone, and silty mudstone (Jiang et al., 2018) (Figure 1C). The matrix porosity of the Chang 8 member ranges from 3.0% to 15.0%, and the matrix permeability ranges from 0.01 to 5.0 md (Wang et al., 2018).

The complicated pore structure and ultralow porosity and permeability of the Chang 8 tight sandstone were caused by diagenesis (Lai et al., 2013; Li et al., 2017), including compaction or cementation that was unfavorable for the preservation of effective pore spaces and pore throats. Shi et al. (2011) reported that the diagenetic facies of the Chang 8 tight sandstones have six subtypes (i.e., weak corrosion with chlorite mat, corrosion of unstable components, tectonic fracture, compaction density, kaolinite filling, and carbonate cementation) (Figure 2). According to their contributions to the sandstone’s history, these six diagenetic facies can be further divided into constructive diagenetic facies and destructive diagenetic facies (Shi et al., 2011). The constructive diagenetic facies, including weak corrosion with chlorite mat, corrosion of unstable components, and tectonic fractures, are a positive factor in improving Chang 8 tight sandstone pore structure and pore connectivity. Compaction density, kaolinite filling, and carbonate cementation diagenetic facies are considered to be destructive to the Chang 8 member. The tectonic stresses caused the Chang 8 to develop many fractures. As a result, nearly no natural hydrocarbon production is present in the intervals in which fractures are not developed (Zhang et al., 2017; Taleghani et al., 2018).

METHODS AND MODELS

Porosity Spectrum Extraction

The formation microresistivity scan image (formation microimager [FMI]) tool, a typical borehole electrical image method, contains 4 pads and 4 flaps located around the borehole, and a total of 192 button electrodes (Ekstrom et al., 1987; Luthi

![Figure 3. An example of a formation microimager (FMI) image in fractured reservoirs and the corresponding porosity spectra derived using the techniques shown by equation 3 in the Luo 60 well in the study area. The FMI image is shown in the second track, and the porosity spectrum is shown in the third track. For fractured formations, the FMI image exhibits dark sine curves (marked by red sine curves), and the porosity spectra have bimodal distributions. The first peak represents the matrix porosity distribution, and the second peak is the response of secondary porosity (fracture or vug). For nonfractured formations, the porosity spectra exhibit unimodal distributions. CM = centimeter; GAPI = the API unit of gamma ray-log; GR = gamma-ray log; VCAL = vertical caliper log; VSP = vertical spontaneous potential log.](image)
and Souhaité, 1990). In practice, a total of 192 formation conductivity data points can be equally obtained around the borehole wall using 0.5-cm (0.2-in.)-wide electrodes and 0.25-cm (0.1-in.) longitudinal resolution (Williams-Stroud et al., 2010; Aslanyan et al., 2015; Valentin et al., 2018). An imaging technique is then used to transform the recorded conductivity data to obtain the borehole image, and parameters associated with fractured formations, such as fracture porosity, length, density,

**Table 1. The Physical Properties and the Corresponding Mercury Injection Capillary Pressure Experimental Results for 37 Core Samples Drilled from the Upper Triassic Chang 8 Tight Sandstone in the Jiyuan Area of the Ordos Basin, Northcentral China**

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<tr>
<th>Core No.</th>
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<th>Permeability, md</th>
<th>Swanson Parameter</th>
<th>Maximal Pore-Throat Radius, μm</th>
<th>Median Radius, μm</th>
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Abbreviation: / = not applicable.
Figure 4. Illustrations of a typical porosity spectrum (A), the casting thin section (B), the formation microimager (FMI) image (C), the mercury injection capillary pressure (MICP) curve (D), and the corresponding pore-throat radius ($R_c$) distribution (E) in a formation with natural fractures in the Huang 44 well. In a fractured formation, the porosity spectrum shows wide unimodal or bimodal distributions, fractures can be easily identified in the casting thin section, the FMI image exhibits a dark sine or cosine curve, the MICP curve lies at the bottom, and the $R_c$ exhibits a wide bimodal distribution. GAPI = the API unit of gamma-ray log; GR = gamma-ray log.
Figure 5. Illustrations of a typical porosity spectrum (A), the casting thin section (B), the formation microimager (FMI) image (C), the mercury injection capillary pressure (MICP) curve (D), and the corresponding pore-throat radius \(R_c\) distribution (E) in a nonfractured formation in the Luo 24 well. In this formation, the porosity spectrum is narrow with unimodal distribution, fractures cannot be identified in the casting thin section, the FMI image is bright, the MICP curve lies at the top, and the \(R_c\) exhibits a narrow unimodal distribution. GAPI = the API unit of gamma-ray log; GR = gamma-ray log.
and width, can also be calculated (Cheung and Heliot, 1990; Sullivan and Schepel, 1995; Ezati et al., 2018). High resolution makes FMI logs applicable in the identification of thin beds (Harthy et al., 2010).

Assuming that the electrical images from the FMI tool are essentially a conductivity map of the borehole wall, primarily from within the mud-flushed zone, an expression derived from the classic Archie’s equation that connected the effective porosity $\varphi$, formation resistivity $R_{xo}$, mud filtrate resistivity $R_{mf}$, and water saturation $S_{xo}$ can be written as follows (Archie, 1942):

$$\varphi_m = \frac{abR_{mf}}{S_{xo}R_{xo}}$$

In this equation, $\varphi$ can be estimated from conventional well log data (such as density, neutron, or sonic) (Wyllie et al., 1956; Widmyer and Wood, 1958; Ellis, 2003); $R_{xo}$ can be transformed from the recorded conductivity value of the FMI tool; and $a$, $b$, $m$, and $n$ are rock resistivity parameters.

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**Figure 6.** An example of acquiring a reverse cumulative curve from a porosity spectrum in 2574.13 m (8445.31 ft) of the Huang 44 well. POR = porosity interval.

**Figure 7.** Principle of acquiring the value of $1/\text{porosity interval (POR)}$ for each mercury injection capillary pressure ($P_c$) increment. $S_o = \text{oil saturation}$; $S_{Hg} = \text{mercury injection saturation}$.
and their values can be estimated using rock resistivity experiments (Archie, 1942; Waxman and Smits, 1968; Waxman and Thomas, 1974). By setting \( S_{xo} = 1 \), \( a = b = 1 \), and \( m = n = 2 \) in equation 1, Newberry et al. (1996) first transformed the FMI image into a porosity map using the following:

\[
\varphi = \left( \frac{R_{mf}}{R_{xo}} \right)^{1/2}
\]  

(2)

The assumption that the pore spaces are only occupied by water (\( S_{xo} = 1 \)) in a flushed zone is not always valid because there are some unflushed hydrocarbons remaining in the invaded zone (Fu et al., 2016). Under such circumstances, the value of \( S_{xo} \) is less than 1.0. Moreover, \( R_{mf} \) must be calibrated in the water layer. A number of studies revised equation 2 and developed a method to derive a porosity map from the FMI image (Akbar et al., 2000; Xie et al., 2015; Zhao et al., 2017):

\[
\varphi_{FMI} = \left( \frac{abR_{mf}}{S_{xo}} \right)^{1/m} = \left( \frac{abR_{mf}}{S_{xo}}R_{xo} \right)^{1/m} \times C_i = \left( \varphi R_{xo} \right)^{1/m} = \varphi \times (R_{xo} \times C_i)^{1/m}
\]  

(3)

where \( \varphi_{FMI} \) is the calculated image porosity from the FMI image in a fracture, and \( C_i \) is the recorded electrical conductivity of each FMI electrode in an FMI measurement. The value of \( R_{xo} \) is generally obtained from a conventional shallow lateral or induction log.

By using equation 3, the conductivity of each FMI button can be transformed into the porosity domain. Eventually, the porosity data from all FMI pads and flaps over a sliding window of 3 cm (1.18 in.) that can be used to obtain a porosity spectrum. By using the procedures outlined above, a porosity spectrum was extracted from the FMI data in the Luo 60 well in the study area (Figure 3). In the porosity spectrum, the x-axis represents the porosity interval (POR), and the y-axis represents the frequency of occurrence for the specific micropores. The shape of the porosity spectra is associated with the formation porosity types. Generally, formations with developed fractures contain wide unimodal or bimodal porosity spectra (the interval of 2423.8–2424.1 m [7952.1–7953.1 ft] in Figure 3), and more-heterogenetic formations have wider pore spectra. For nonfractured reservoirs, the porosity spectra display narrow and sharp unimodal patterns (up to 2422.5 m in Figure 3).

**Table 2.** The Classification Criteria and the Corresponding Models of Constructing Pseudocapillary Pressure Curves from the Porosity Spectra in the Upper Triassic Chang 8 Tight Sands of the Jiyuan Area, Ordos Basin

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<th>Type of Rock</th>
<th>Range of Porosity, ( \varphi )</th>
<th>Established Models</th>
</tr>
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<td>( \varphi \geq 12.8% )</td>
<td>( y = 7e + 07x^{6.02} )</td>
</tr>
<tr>
<td>2nd</td>
<td>( 8.0% \leq \varphi &lt; 12.8% ))</td>
<td>( y = 270203x^{4.73} )</td>
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<td>3rd</td>
<td>( \varphi &lt; 8.0% )</td>
<td>( y = 4811.3x^{2.99} )</td>
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<table>
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<th>Large Pore Throat (Low ( P_c ))</th>
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<tbody>
<tr>
<td>( y = 5e + 09x^{8.86} )</td>
<td>( \varphi_{FMI} = \left( \frac{abR_{mf}}{S_{xo}} \right)^{1/m} \times C_i = \left( \varphi R_{xo} \right)^{1/m} )</td>
<td></td>
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<th>Establish Models</th>
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<tr>
<td>( y = 85.14x^{1.51} )</td>
<td>( y = 6e + 09x^{2.39} )</td>
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</table>

Abbreviation: \( P_c \) = pseudocapillary pressure.
Relationship between Porosity Spectrum and Pore Structure

The FMI data acquired from six wells in the Jiyuan area of the Ordos Basin were processed as outlined above (equations 1–3) to acquire the porosity spectra. Additionally, laboratory mercury injection experiments were conducted to obtain mercury injection $P_c$ (MICP) curves and the corresponding $R_c$ distributions for a total of 37 core samples that were drilled in the study area (Table 1). In the mercury injection experiment, core samples were first fully saturated with brine, and mercury was then injected into the pore spaces to simulate hydrocarbons. With the increase of the injection pressure, brine was gradually displaced. The mercury injection saturation ($S_{Hg}$) under various mercury injection pressures was recorded to obtain the MICP data. The experimental data were then processed using a method proposed by Tiab and Donaldson (2012) to obtain the $R_c$ distributions and the pore structure evaluation parameters. In addition to the mercury injection experiments, more than 80 casting thin sections were made to observe the characteristics of fractures.

To obtain the relationship between the porosity spectrum and the pore structure, the FMI image and the porosity spectra that were adjacent to the depth of the core samples were acquired. The FMI image and the porosity spectra were analyzed side by side with the MICP curve, $R_c$ distributions, and casting

![Figure 9](image-url). The average mercury injection capillary pressure curves (A), average pore spectrum (B), and corresponding average reverse cumulative curve (C) for three rock types in the Upper Triassic Chang 8 tight sandstones of the Jiyuan area, Ordos Basin. POR = porosity interval.
thin sections. For the fractured formations, fractures are clearly identified from the casting thin section and the FMI image. The MICP curve shows a low position, and the $R_c$ distribution displays bimodality, which indicates good pore structure (Figure 4). For a tight sandstone formation without fractures, the porosity spectrum is narrow with unimodal distribution, and the position of the peak is located in the left. The position of the MICP curve, however, became high, and the $R_c$ spectrum displays unimodal distribution because of poor pore structure (Figure 5).

The MICP curve and $R_c$ distribution acquired from mercury injection experiments of core samples are valuable for pore structure quantitative evaluation in the laboratory (Volokitin et al., 2001; Xiao et al., 2016). However, they cannot be used to evaluate consecutive formation pore structure in field applications because of the limited number of core samples (Xiao et al., 2016). Additionally, formation pore structure cannot be evaluated by using MICP curve and $R_c$ distribution in uncored wells. Figures 4 and 5 illustrate that the MICP curve and $R_c$ distribution correspond to the porosity spectrum both in fractured and nonfractured formations. However, the physical significance of each is different. To characterize a fractured formation pore structure using the porosity spectrum, an effective model has to be established to transform the porosity spectrum as a $P_c$ curve and $R_c$ distribution.

Figure 10. Models that are used to construct pseudocapillary pressure curves from the porosity spectra for three rock types in the study area. POR = porosity interval; $R^2$ = correlation coefficient.
Pore Structure Evaluation Model

Acquisition of a Reverse Cumulative Curve from a Porosity Spectrum
To establish a robust model to obtain a $P_c$ curve from the porosity spectrum, the porosity spectrum was first processed to obtain a reverse cumulative curve, which has a similar shape to the MICP curve (Figure 6). In this method, the amplitude of the porosity spectrum was reversely cumulated with porosity, decreasing from 100% to 0, and was normalized to obtain the reverse cumulative saturation displayed as the $x$-axis. Porosity was a token reciprocal displayed in the $y$-axis to acquire the reverse cumulative curve.

Construction of a Pseudocapillary Pressure Curve from the Reverse Cumulative Curve
To transform the reverse cumulative curve to a $P_c$ curve, a relationship between $P_c$ and $1/\text{POR}$ is established. Figure 7 displays a method of extracting the value of $1/\text{POR}$ under each mercury injection pressure increment ($P_c$). In this process, the reverse cumulative curve and the MICP curve are plotted using the same $x$-axis. From every injection pressure

![Graphs](image)

**Figure 11.** Comparisons of synthetic pseudocapillary pressure ($P_c$) curves with measured results illustrate the reliability of the models. MICP = mercury injection capillary pressure.
increment, a line that contained the same saturation value was drawn to intersect with the reverse cumulative curve, and the corresponding 1/POR is acquired.

The values of 1/POR for each mercury injection pressure increment were extracted and crossplotted with the corresponding Pc value (Figure 8). This figure suggests that a good power function relationship exists between 1/POR and Pc. However, it should be noted that no single relationship exists between 1/POR and Pc for all core samples or even for a single core sample. A classified power function (CPF) may be used to accurately construct a Pc curve using the porosity spectrum. This method involves the following procedures.

1. Processing the FMI image logs using equation 3 to obtain the consecutive porosity spectra.
2. Drilling a large number (≥20) of core samples from the same region for mercury injection experiments to obtain MICP data and corresponding Rc distribution and extracting the porosity spectra under the same or adjacent depth with core samples and then using the method displayed in Figure 6 to calculate the reverse cumulative curves.
3. Establishing a rock classification criterion to divide the MICP data and the corresponding reverse cumulative curves into several types and calculating the average MICP curves and reverse cumulative curves for each type of core sample.
4. Extracting the values of 1/POR under every Pc value based on the average MICP and reverse cumulative curves and establishing the relationships between 1/POR and Pc based on power functions. It should be noted that for each type of rock, two power functions must be used to express the relationship between 1/POR and Pc.

For the same type of core sample, the Pc curves can be related to 1/POR according to equation 4, based on the CPF method:

\[ P_c = c \times \left( \frac{1}{\text{POR}} \right)^d \]  \hspace{1cm} (4)

where c and d are the statistical model parameters, and their values can be calibrated by using the core experimental results. One needs to note that the pore spaces must be first classified into two groups or classes (small and large pore-throat sizes) in the CPF method, and for every part of the pore space, the respective involved model parameters are used.

The demarcation of small and large pore-throat sizes for a core sample was determined by the shapes of MICP curves and porosity spectra. Small pore-throat size corresponded with a relatively high Pc value and the first peak in the porosity spectrum, whereas large pore-throat size was associated with a...
relative low $P_c$ value and the second peak. Finally, by combining the predicted $P_c$ with the reverse cumulative saturation, $P_c$ curves were synthetized. Once the established models were extended into field applications, consecutive $P_c$ curves could be constructed in the intervals from which borehole electrical image data were acquired. Meanwhile, the classic relationship between $P_c$ and $R_c$ expressed in equation 5 can be used to acquire $R_c$ distribution from the constructed $P_c$ curve:

$$P_c = \frac{2\sigma \cos \theta}{R_c}$$

(5)

where $R_c$ is the rock $R_c$ (μm), $\sigma$ is the surface tension between two phases fluid (dyn/cm), and $\theta$ is the contact angle (°).

Calibration of Model Parameters
To make the established models applicable to target formations, the MICP curves and the corresponding porosity spectra that were extracted from the adjacent depths of 37 core samples were classified into 3 categories, according the effective porosity (Table 2). Accordingly, the average MICP curves, the average porosity spectra, and the corresponding average reverse cumulative curves were computed (Figure 9).

Figure 9 shows that with the decrease in porosity, the average MICP curves increase, and the average porosity spectra become narrower and shift to the left. Additionally, the corresponding average reverse cumulative curves also increase with decreasing porosity. By combining the average MICP...
curves and the corresponding average reverse cumulative curves for three rock types, the values of 1/POR can be extracted under every $P_c$ curve. By plotting 1/POR and $P_c$ for each rock type, the parameters involved in the models were individually derived (Figure 10). These figures show that power functions provide good fits between 1/POR and $P_c$ with correlation coefficients greater than 0.95. The models that are used to transform the porosity spectra into $P_c$ curves are listed in Table 2.

**Model Reliability Evaluation**

The established models were evaluated by applying them to field conditions. Three typical $P_c$ curves, which were extracted from approximately the same depth of core samples, were compared with the experimental results (Figure 11). These results show that the measured MICP curves match well with the synthetic results. This ensures the reliability of the proposed model.

**Permeability Prediction Model**

Besides pore structure evaluation, another important application of the $P_c$ curve is permeability estimation (Swanson, 1981). Xiao et al. (2014) proposed a permeability prediction method, which was particularly valuable for tight sandstones, based on the Swanson parameter. Based on this method, if the $S_{Hg}$ (x-axis), and mercury injection pressure increment

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Figure 15. A field example of evaluating nonfractured formation pore structure by using the proposed techniques in tight sandstone reservoirs with no hydrocarbon production in the Luo 42 well. AC = acoustic log; CAL = caliper log; CNL = compensated neutron log; $CP_{50}$ = core-derived median pressure; $CP_{max}$ = core-derived maximum pore-throat radius; $SP_{50}$ = core-derived threshold pressure; $CSWANSON$ = core-derived Swanson parameter; DEN = density log; GR = gamma-ray log; $P_{50}$ = median pressure; PC_Dist = capillary pressure distribution; PD = threshold pressure; PERM = permeability; $PERMSWAN$ = permeability predicted by using the Swanson parameter based model; POR_Dist = porosity spectrum distribution; $R_{50}$ = core-derived median pore-throat radius; $RC_{max}$ = maximum pore-throat radius; $RT$ = true formation resistivity; $RXO$ = flushed zone formation resistivity; $SP$ = spontaneous potential log; $SWANSON$ = the Swanson parameter.
(y-axis) is displayed in log–log coordinates, the MICP curve can be presented as a hyperbolic curve, and the expression of the hyperbolic curve is expressed as follows:

\[
\log_{10}\left(\frac{P_c}{P_d}\right) \times \log_{10}\left(\frac{S_{Hg}}{S_{Hg}^{\infty}}\right) = C
\]  

(6)

where \(P_d\) is the threshold pressure (MPa), \(S_{Hg}\) is the nonwetting phase saturation under infinite mercury injection pressure (%), and C is the geometric prefactor.

The inflection point of the hyperbolic curve represents the \(S_{Hg}\) threshold in the main pore system, and it is the primary control on fluid flow (Guo et al., 2004; Rezaee et al., 2012). This inflection point is the cutoff point for large and small pore-throat size. In the primary stage of the MICP experiment, nonwetting phase mercury mainly occupies the connected large pore space because of the low mercury injection pressures. As the mercury injection pressures increase, it breaks through the inflection point, and mercury is injected into the small pore space or pore corners with irregular shapes, and the flow capacity experiences a dramatic decline (Thomeer, 1960; Swanson, 1981). The Swanson parameter, which was defined as the maximal value of mercury saturation per pressure and expressed as \((S_{Hg}/P_c)_{max}\), was proposed to express the capacity of fluid flow (Xiao et al., 2014). Following with the proposed method by Xiao et al. (2014), a

Figure 16. The cross-plots of predicted pore structure evaluation parameters and permeability versus core-derived results: (A) the Swanson parameter; (B) the maximum pore-throat radius \((R_{max})\); (C) the median pore-throat radius \((R_{50})\); and (D) the permeability. In these figures, the solid red lines represent the discrepancy of the predicted parameters with those of the core-derived results. The two blue lines indicate a margin of relative error of 30.0%.
model, which predicts fractured reservoir permeability from a $P_c$ curve based on the Swanson parameter, was established (Figure 12). Meanwhile, the routine core-derived porosities and permeabilities for these 37 samples are used to establish a conventional permeability prediction model based on the exponential function (Figure 13). The results show that the Swanson parameter-based permeability model provided a better prediction than that of the conventional method because of the consideration of pore structure.

**CASE STUDIES**

The proposed methods were applied to the Huang 15 well to derive $P_c$ curves and $R_c$ distribution using porosity spectra and to calculate pore structure evaluation parameters and permeability (Figure 14). The results show that for a majority of the studied intervals, the permeabilities are close to 0.1 md. However, for the intervals ranging from 2509.5 to 2510.5 m (8233.3–8236.6 ft), 2512–2513 m (8241.5–8244.8 ft), and 2516–2517 m (8254.6–8257.9 ft), the predicted permeabilities from the $P_c$ curves based on the Swanson parameters are notably higher than 0.1 md, suggesting that the formation fluid flow capacity is enhanced because of the contribution of fractures. Permeabilities estimated using the conventional method did not show the contribution of these fractures. The comparisons between the predicted pore structure evaluation parameters from the constructed $P_c$ curve and those of the core-derived results further show that the pore structure evaluation parameters can be well predicted using the proposed method. This prediction was further verified by the drill-stem test (DST) data in the interval of 2508 to 2512 m (8228.3–8241.5 ft), which showed that approximately 28 bbl of oil was produced per day with no water. As a comparison, this interval was considered to be non–oil producing using the conventional method because the predicted permeabilities are lower than the lower limit of the exploitable formations (Fu et al., 2014). Clearly, the proposed methods of pore structure evaluation successfully identified some intervals worth exploiting that would have been overlooked by conventional evaluation methods.

For nonfractured reservoirs, the porosity spectra and $R_c$ distributions all have narrow unimodal distributions, with low POR and small pore-throat size (Figure 15). The predicted permeabilities from the $P_c$ curves and the conventional method are similar, with values less than 0.1 md. The predicted pore structure evaluation parameters show that the maximal pore-throat radii are less than 0.3 μm and that the threshold pressures are all greater than 3.0 MPa. As a result, these formations are considered nonproducing. These results were also confirmed by the DST data, which show that there was no fluid flow for the intervals of 2730–2731 m (8956.7–8960 ft) and 2732.5–2733.5 m (8964.9–8968.2 ft).

**UNCERTAINTY ANALYSIS**

To quantify the uncertainties associated with the pore structure evaluation parameters and permeability yielded by the modeling process, the relative errors between the predicted pore structure evaluation parameters and permeability with laboratory experimental results were evaluated according to equation 7:

$$re = \frac{|\text{Predicted result} - \text{experimental result}|}{\text{experimental result}} \times 100\%$$

(7)

where $re$ is the relative error between the predicted pore structure evaluation parameters and permeability, with laboratory experimental results (%).

The predicted Swanson parameters maximum pore-throat radius, median pore-throat radius, and permeability from constructed $P_c$ curve and experimental results of core samples were cross-plotted in Figure 16A–D. Considering the relationship of the $P_c$ and $R_c$ expressed in equation 5, the threshold pressure and the median pressure correspond to the maximal $R_c$ and median $R_c$, respectively. The relative errors of predicted threshold pressure and median pressure were not analyzed. The solid red lines in Figure 16A–D represent the diagonal lines, which clarify the discrepancy of the predicted results with that of the core-derived results. These two thin blue lines indicate a margin of relative error of 30.0%.
These comparisons show that the predicted pore structure evaluation parameters and permeability from the synthetized $P_c$ curves are consistent with those of the core-derived results. For the majority of core samples, the relative errors between the predicted results and the core-derived results are lower than 30%. These results suggest that our proposed methods are satisfactory and that the extracted porosity spectrum from FMI logs can be used to evaluate fractured tight sandstone reservoir pore structures.

CONCLUSIONS

The current borehole electrical image logging technique only provides qualitative or semiquantitative information about the pore structure of fractured reservoirs. To evaluate the pore structure of fractured reservoirs in a more quantitative manner, porosity spectra can be processed to obtain $P_c$ curves and $R_c$ distributions. In this study, a method is developed to construct $P_c$ curves from the porosity spectra based on a CPF method. By using this method, formation $P_c$ curves can be consecutively constructed, and the corresponding $R_c$ distribution and parameters associated with the pore structure evaluation are precisely extracted.

This method was evaluated using the DST data from the Upper Triassic Chang 8 tight sandstones of the Jiyuan area in the Ordos Basin in China. The results suggest that this method is superior to existing methods in that it accurately predicted the existence of hydrocarbon-bearing layers where conventional methods failed to identify these zones.

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