Application of Nuclear Magnetic Resonance (NMR) Logs in Tight Gas Sandstone Reservoir Pore Structure Evaluation

Liang Xiao*
China University of Geoscience, Beijing
School of Geophysics and Information Technology
xiaoliang@cugb.edu.cn

Zhi-qiang Mao
China University of Petroleum, Beijing
State Key Laboratory of Petroleum Resource and Prospecting
1159506727@qq.com

Xiu-hong Xie
BrightStars Hi-Tech Development Co. Ltd.
Department of Clinical Research
xiuhong.xie@bic-usa.com

SUMMARY

Based on the simultaneously applied mercury injection capillary pressure (MICP) and nuclear magnetic resonance (NMR) laboratory experimental results for 20 core samples from tight gas sandstone reservoirs of the Sichuan basin, the relationships of the piecewise power function between nuclear magnetic resonance (NMR) transverse relaxation T_2 time and capillary pressure (P_c) are established. A novel method, which is used to transform NMR reverse cumulative curve as pseudo capillary pressure (P_c) curve is proposed, and the corresponding model is established based on formation classification. By using this model, formation pseudo P_c curves can be consecutively synthesized. The pore throat radius distribution, and pore structure evaluation parameters, such as the average pore throat radius (Rm), the threshold pressure (Pd), the maximum pore throat radius (Rmax) and so on, can also be precisely extracted. After this method is extended to field applications, several tight gas sandstone reservoirs are processed, and the predicted results are compared with core derived results. Good consistency between evaluated results with core derived results illustrates the dependability of the proposed method. Comparing with the previous methods, this presented model is much more theoretical, and the applicability is much improved.

Key words: Nuclear magnetic resonance (NMR); Mercury injection capillary pressure (MICP) curve; Pore throat radius distribution; Formation classification; Pore structure

INTRODUCTION

As the exploration interests of geologists are gradually focused on ultra-low permeability to tight sandstone reservoirs, common methods will be out of action in identifying effective hydrocarbon bearing formations. To improve formation evaluation and exploration efficiency, pore structure should be quantitatively characterized (Xiao et al., 2012). Mercury injection capillary pressure (MICP) data is considered to be the most effective in quantitatively evaluating rock pore structure (Purcell, 1950; Rose and Bruce, 1949; Brown, 1951). Hence a certain amount of core samples are acquired in exploration wells for MICP experimental measurements. However the MICP data is always limited due to environment, time and cost considerations (Eslami et al., 2013).

Specialists have pointed out that the NMR logs are effective in indicating rock pore structure (Coates et al., 2000; Dunn et al., 2002). From the NMR spectrum, the pore size and distribution can be qualitatively predicted. To quantitatively evaluate rock pore structure from NMR logs, the best method is constructing pseudo P_c curves from NMR logs, and in the past decade many methods have been proposed (Volokitin et al., 2001; Altunbay et al., 2001; Ouzzane et al., 2006; Green et al., 2008; Hamada, 2009; Olubunmi et al., 2011; Xiao et al., 2012; Eslami et al., 2013). However, these were empirical statistical methods; the essential relationship between the NMR T_2 spectrum and pore throat size distribution is not revealed. In this study, based on the lab experimental measurements, the relationship of power function between the NMR T_2 spectrum and pore throat size distribution is exposed, and a new method and technique of synthetizing pseudo P_c curves from NMR logs is proposed.

PRINCIPLE OF CONSTRUCTING PC CURVES FROM NMR MEASUREMENTS

Generally, for a water-wet rock fully saturated by brine, the NMR transverse relaxation time T_2 is dominated by the surface relaxation time T_{2S}; the bulk relaxation time T_{2B} and the diffusion relaxation time T_{2D} can be disregarded. The value of T_{2S} is usually controlled by the pore size of rock. Hence, the T_2 relaxation time can be expressed as follows (Coates et al., 2000; Dunn et al., 2002);

$$\frac{1}{T_2} \approx \frac{1}{T_{2S}} = \rho_2 (\frac{S}{V})_{por} = F_S \frac{\rho_2}{r_{por}} \qquad (1)$$

where, T_2 is the NMR transverse relaxation time in ms; ρ_2 is the proportionality constant between $1/T_2$ and surface to volume ratio of the pore; S is the surface area of rock pore, and V is the volume of rock pore. S/V is called the surface relaxivity. The subscript of por stands for rock pore; r_{por} is the pore radius in micrometers; F_s is the geometric factor of pore shape. For a rock with spherical pores, the value of F_s is 3, and for columnar pores, F_s is equal to 2.

Based on the theory of capillary pressure, if we assume that the pore size and pore throat radius is proportional, the relationship between P_c and T_2 can be expressed as follows;

$$P_c = C \times \frac{1}{T_2} \tag{2}$$

where, C is the conversion coefficient of NMR T_2 relaxation time and capillary pressure P_c.

METHOD OF CONSTRUCTING PSEUDO PC CURVE FROM NMR LOGS

Principle of acquiring optimal C from NMR logs

Observing equation 2, we can conclude that the NMR T_2 spectrum can be transformed as pseudo capillary pressure curves, and thus rock pore throat radius size once the value of $\boldsymbol{C}$ is well calibrated. To obtain accurate C, the NMR T_2 amplitude is reversely cumulated and normalized to obtain the reverse cumulative saturation. A cross plot of reversely cumulated saturation and $1/T_2$ provides an NMR reverse cumulative curve. The principle of obtaining the NMR reverse cumulative curve is displayed in Figure 1. In Figure 2, the method of calibrating C from NMR logs is displayed. After the optimal C is acquired, the NMR reverse cumulative curve will move to the MICP curve.

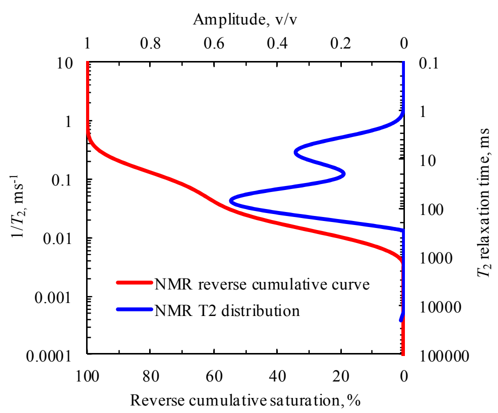

Figure 1: Principle of acquiring NMR reverse cumulative curve from NMR T_2 distribution

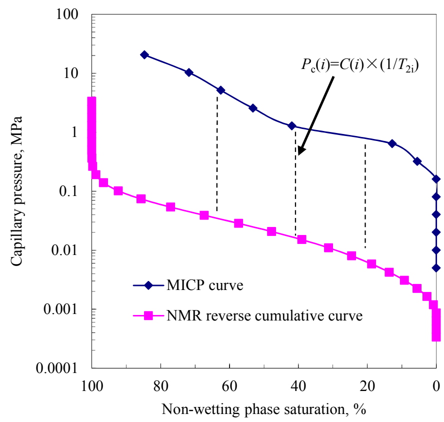

Figure 2: Principle of obtaining optimal C from NMR logs.

Relationships of T_2 and P_c

To determine the optimal C displayed in Figure 2, NMR and MICP measurements of 20 core samples from tight gas sands in the central Sichuan Basin, northwest China, were obtained, and the NMR spectra, MICP curves and the corresponding R_c distribution acquired. The NMR reverse cumulative curves and the corresponding MICP curves were compared, the NMR T_2 relaxation times corresponding to every mercury injection pressure increment obtained.

To understand the relationship of P_c with T_2, the acquired T_2 under every P_c increment and the corresponding P_c are analysed. The NMR spectra, MICP curves, the NMR reverse cumulative curves, and the crossplots of $1/T_2$ versus P_c for 4 typical core samples are made and displayed through figures 3 to 6, separately. The figures marked (a) are the laboratory NMR T_2 distributions, MICP curves are marked as (b), figures marked as (c) are the NMR reverse cumulative curve for the core sample, crossplot of $1/T_2$ versus P_c is displayed in (d).

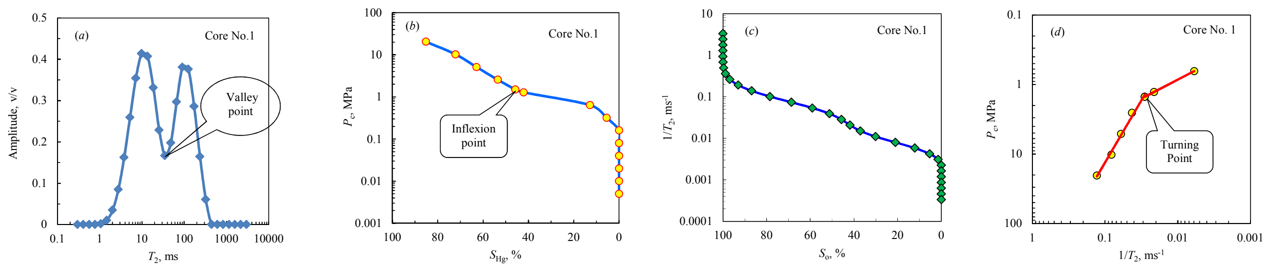

Figure 3: The relationships of $1/T_2$ versus P_c for core No.1 with typical bimodal NMR spectrum.

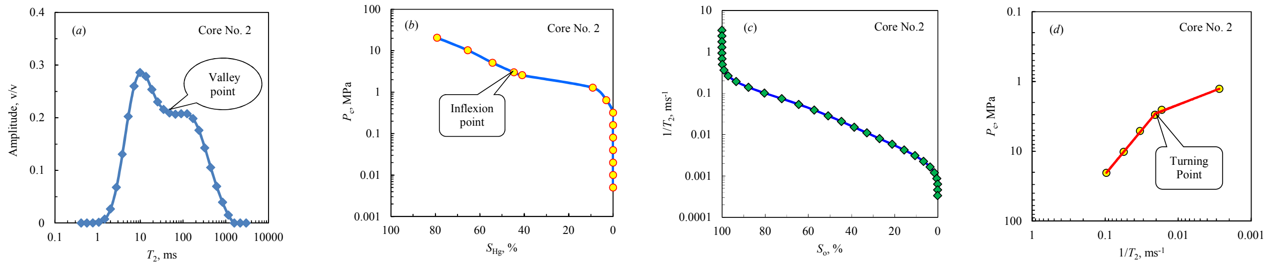

Figure 4: The relationships of $1/T_2$ versus P_c for core No.2 with typical bimodal NMR spectrum.

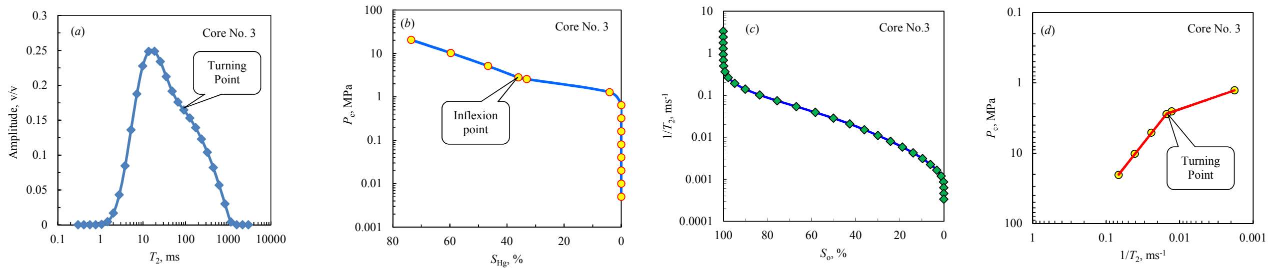

Figure 5: The relationships of $1/T_2$ versus P_c for core No.3 with non-typical bimodal NMR spectrum.

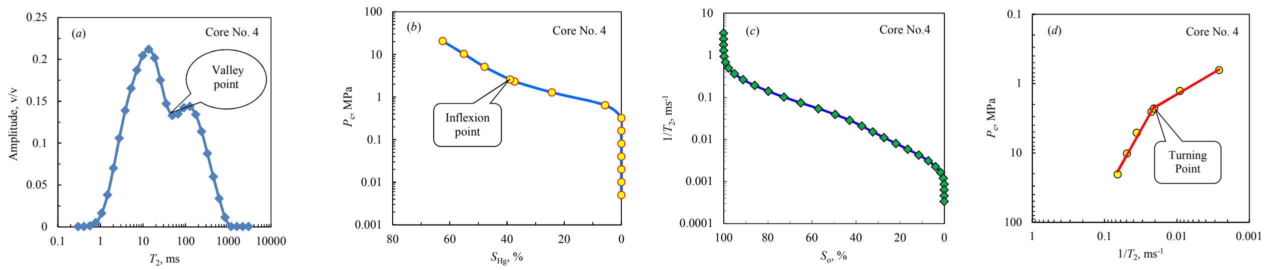

Figure 6: The relationships of $1/T_2$ versus P_c for core No.4 with typical bimodal NMR spectrum.

Observing figures 3 to 6, several regular conclusions can be generalized as follows:
(1) The valley points of NMR spectra and the inflexion points of MICP curves are related. The MICP curve with higher P_c corresponds to the T_2 spectrum with short transverse relaxation time. On the contrary, The MICP curve with lower P_c is corresponding to the T_2 spectrum with long transverse relaxation time.
(2) The relationship between $1/T_2$ versus P_c is not the simple linear function proposed by Volokitin et al. (2001), and not a complicated function. They are the non-linear power function; in log-log coordinates, they have a linear relationship.
(3) The function between the $1/T_2$ and P_c are not unified, they are segmented. That is to say, in the parts of big pore size and small pore size for the same core samples, the transformation functions of $1/T_2$ and P_c are entirely different. There are the turning points between them, such as the figures marked (d) in figures 3 to 6. The turning point is consistent with the valley point of the NMR distribution and the inflexion point of MICP curve.

Procedures of determining optimal C from NMR logs

To obtain the optimal C to construct pseudo Pc curve from NMR logs, the following procedures should be applied:
(1) Collect base experimental data for the same core samples, being routine porosity and permeability, and the NMR and MICP measurements.
(2) Acquire the NMR reverse cumulative curve from NMR T_2 distribution following the principle exhibited in Figure 1.
(3) Compare the shapes of the NMR reverse cumulative curve and the MICP curves for the same cores, and acquire the T_2 value corresponding to each mercury injection pressure increment.
(4) Analysing the relationship of T_2 and P_c, establish the scale conversion model based on the subsection power function. Then, the optimal C can be acquired.

Synthetizing pseudo Pc curve from NMR logs based on formation classification

If we want to construct a pseudo P_c curve from field NMR logs following the proposed technique, the relationship between the NMR T_2 time and P_c should be first established. The best method is consecutively establishing the scale conversion relationship of these two parameters. This is not realistic in field applications where core samples with NMR and MICP experimental measurements are limited. Hence, the established model based on limited experimented measurements cannot be directly extended to uncored formations or wells. To improve the wide applicability of the proposed technique, a new method based on formation classification is proposed, and we named it the Classified Piecewise Power Function (CPPF) method. In the CPPF method, core samples are first classified into several types; second, the piecewise power functions are used to establish the relationship of T_2 and P_c; finally, the established classification criteria based on core samples are extended to field applications to classify formations where field NMR logs were acquired, and the corresponding piecewise power functions are used to transform the field NMR logs as consecutive pseudo P_c curves based on above procedures.

FIELD APPLICATIONS OF TIGHT GAS SANDS IN CENTRAL SICHUAN BASIN

Determining optimal C based on the formation classification method

In our Sichuan Basin study, 20 core samples were subjected to routine core analysis, laboratory NMR and MICP measurements. Based on the shapes of MICP curves, these core samples are classified into three types based on the pore structure index ($\sqrt{K/\varphi}$). The classification criteria are listed in Table 1.

Table 1: The classification criteria of tight gas sands in central Sichuan

Type of rocks	Classification criteria of $\sqrt{K/\varphi}$
1st type	$\sqrt{K/\varphi} \geqslant 0.35$
2nd type	$0.22 \leqslant \sqrt{K/\varphi} < 0.35$
3rd type	$\sqrt{K/\varphi} < 0.22$

Based on the classification criteria, the 20 core samples are classified into three types. The average MICP curve and NMR distribution for every type of core sample is obtained. Figures 7a and b display these three types of average MICP curves and NMR T_2 distributions, respectively. Figure 7c is the corresponding NMR reverse cumulative curves obtained from the average NMR T_2 distributions. From these figures, we can observe that these three typical curves can be clearly classified, this means the established classification criteria are credible.

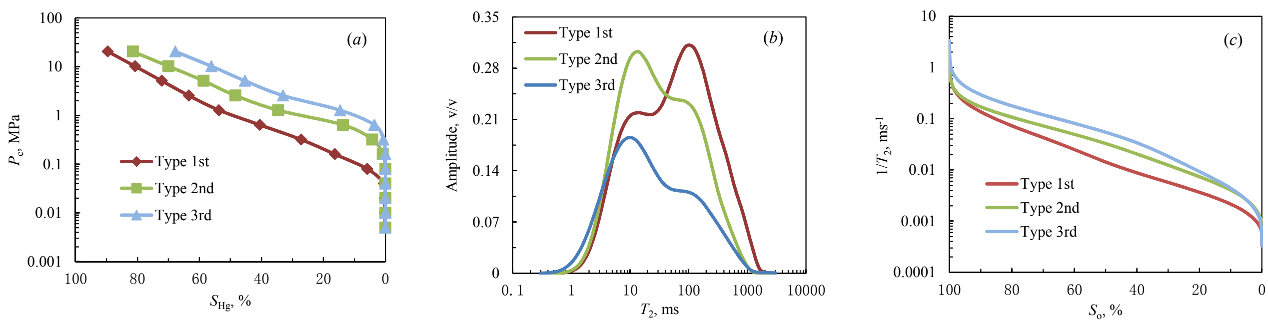

Figure 7: Three types of average MICP curves, NMR spectra and the corresponding NMR reverse cumulative curves.

To establish the relationship of T_2 and P_c, the T_2 times that corresponding to every P_c is obtained, and the crossplot of T_2 and P_c is made. As a result, good power functions between $1/T_2$ and P_c for every rock type are established. Meanwhile, for every rock type, a typical turning point exists, meaning different power functions should be used to express the relationship of T_2 and P_c. The relationships of $1/T_2$ and P_c for three types of rocks are displayed in Figure 8.

CASE STUDY

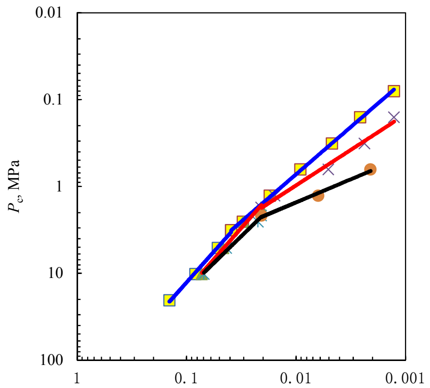

Figure 8: Relationships of $1/T_2$ versus P_c for three types of rocks.

Based on the proposed technique, several wells in the central Sichuan Basin, southwest China were processed, and Figure 9 displays a field example. In the sixth track of Figure 9, PC_DIST is the constructed pseudo P_c curves from field NMR logs, and RC_DIST displayed in the seventh track is the derivative pore throat radius distribution from NMR spectra. In the eighth and ninth tracks, we displayed the comparisons of estimated permeability and porosity from conventional methods with the derived results from routine core analysis, separately. Good consistency indicates that porosity and permeability are precisely predicted, this ensures these two parameters can be used to effectively classify formations into three types. Through the tenth to fourteenth tracks, we compare the pore structure evaluation parameters extracted from pseudo P_c curves and derived from routine core analysis. These pore structure evaluation parameters are the average pore throat radius (RM), median pore throat radius (R50), maximum pore throat radius (RMAX), threshold pressure (PD) and median pressure (P50). Letter C marked before these five parameter symbols stands for the core derived results. These comparisons illustrate that the predicted values of pore structure evaluation parameters match with the core analysed results very well, verifying the proposed technique is available for constructing pseudo P_c curves from NMR logs. Combining with these extracted results, formation pore structure can be quantitatively evaluated, and effective reservoirs can be identified.

CONCLUSIONS

(1) NMR logs are of great importance in qualitatively characterizing rock pore structure and evaluating pore size distribution. If we want to quantitatively characterize rock pore structure using NMR logs, they should be first transformed as pseudo P_c curves.

(2) Based on the analysis of laboratory measurements in tight gas sandstone reservoirs of the central Sichuan Basin, the relationship of piecewise power functions between $1/T_2$ and P_c are proposed. Using this power function, the NMR T_2 distribution can be accurately transformed as pore throat radius distribution, and the pseudo P_c curve can be synthesized.

(3) Based on the formation classification method, rocks are classified into three types, and the relationships of T_2 and P_c for every rock type are established. After this method is extended to field applications, consecutive pseudo P_c curves can be constructed.

(4) Field applications show that the proposed method is applicable, and the constructed pseudo P_c curves are dependable. They can replace experimentally measured MICP curves to quantitatively evaluate the pore structure of tight gas sandstone reservoirs.

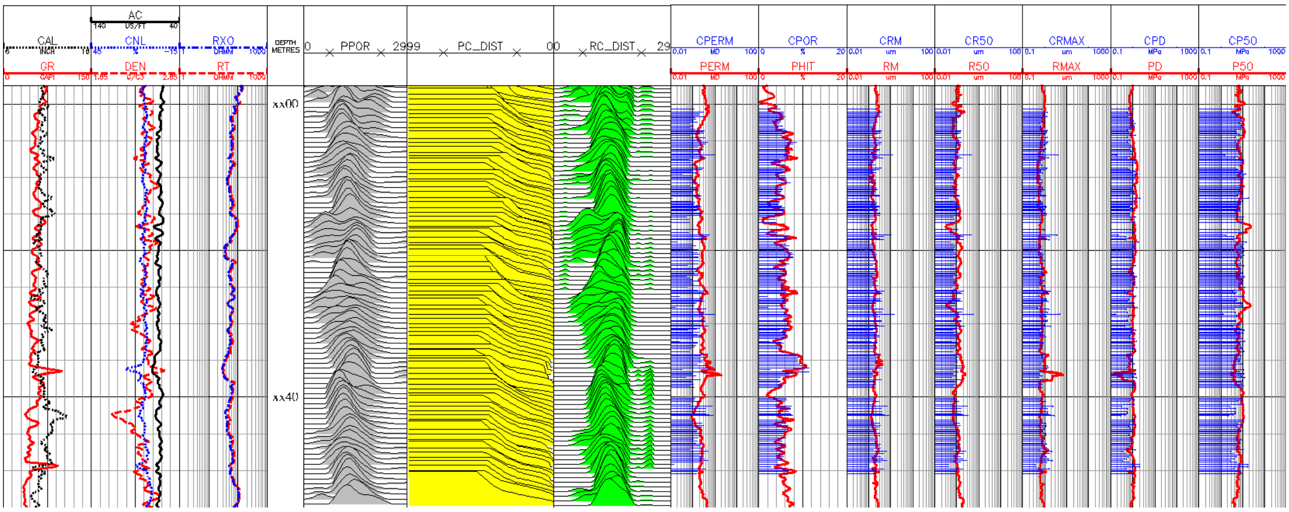

Figure 9: A field example of evaluating formation pore structure from pseudo P_c curves in tight gas sandstone reservoirs.

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