Available online at www.sciencedirect.com

ScienceDirect

Natural Gas Industry B 2 (2015) 481—488

www.elsevier.com/locate/ngib

Research article

Quantitative characterization of fractures and pores in shale beds of the Lower Silurian, Longmaxi Formation, Sichuan Basin

Wang Yuman*, Huang Jinliang, Li Xinjing, Dong Dazhong, Wang Shufang, Guan Quanzhong

PetroChina Research Institute of Petroleum Exploration & Development, Beijing 100083, China

Received 7 April 2015; accepted 8 December 2015
Available online 22 April 2016

Abstract

Fractures and pores are important storage and percolation spaces in tight reservoirs, and the identification, characterization and quantitative evaluation on them are the key aspects and difficulties in shale gas reservoir evaluation. In view of this, quantitative evaluation was performed on the fracture porosity of organic-rich shale intervals of Longmaxi Fm, Lower Silurian, Sichuan Basin (Wufeng Fm, Upper Ordovician included), after a dual-porosity medium porosity interpretation model was built on the basis of drilling data of Fuling Gasfield and Changning gas block in the Sichuan Basin. And then, the following conclusions are reached. First, shale fracture porosity interpretation by using dual-porosity medium model is the effective method to evaluate quantitatively the fracture porosity of shale reservoirs, and the development of quantitative characterization techniques of marine shale reservoir spaces. Second, the matrix pore volume of the principal pay zones in this area and its constitution regions are stably distributed with matrix porosity generally in the range of 4.6%—5.4%. And third, the development characteristics of fracture porosity vary largely in different tectonic regions and indifferent wellblocks and intervals even in the same tectonic region, presenting strong heterogeneity in terms of shale reservoir storage and percolation properties. It is indicated by quantitative characterization of fractures and pores that there are two types of shale gas reservoirs in Wufeng Fm — Longmaxi Fm, Sichuan Basin, including matrix porosity + fracture type and matrix porosity type. The former are mainly developed in the areas with special structure settings and they are characterized by developed fracture pores, high gas content, high free gas content, thick pay zones and high single-well production rate. And in the Sichuan Basin, its distribution is possibly in a restricted range. The latter are characterized by high matrix porosity, undeveloped fracture porosity and medium—high single-well production rate. And it is predicted that marine shale gas is predominant in this basin.

Keywords: Sichuan Basin; Early Silurian; Late Ordovician; Organic-rich shale; Matrix porosity; Shale fracture; Fracture porosity; Petrophysical model; Dual-porosity medium

1. Geologic setting

In recent years, with the discovery of a batch of high-yield shale gas fields (provinces) like Changning, Yanggaosi and Fuling (Fig. 1) and the ceaselessly deepening of shale gas reservoir evaluation, natural fractures, the main factor controlling the enrichment and high yield of gas, has become one of the main study objects of reservoir characterization [1—16]. We have ever conducted characterization study on the reservoir space of Lower Silurian Longmaxi Fm shale in southern Sichuan Basin [12], and briefly described the development features of natural fractures in organic-rich shale. By their width, natural fractures are divided into 5 levels: microfractures (<0.1 mm), mini-fractures (0.1—1 mm), moderate fractures (1—10 mm), macrofractures (10—100 mm) and huge fractures (>100 mm), which helped to preliminarily reveal the distribution patterns and control factors of natural fractures in the Longmaxi Fm [12]. Ding Wenlong and Nie Haikuan et al., based on shale gas data and test data both at home and abroad, conducted qualitative analysis on the main control factors

* Corresponding author.
E-mail address: wangyuman@petrochina.com.cn (Wang YM).
Peer review under responsibility of Sichuan Petroleum Administration.

http://dx.doi.org/10.1016/j.ngib.2015.12.002

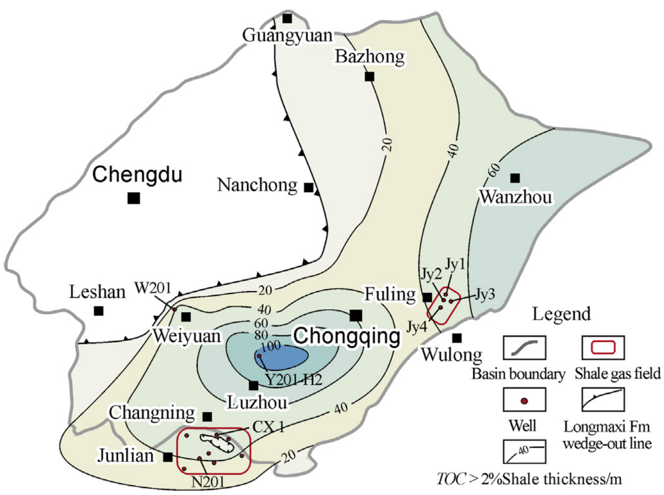

Fig. 1. Distribution of organic-rich shale and wells drilled in the Lower Silurian Longmaxi Fm of the Sichuan Basin.

affecting the development of shale fractures in terms of nonstructural factors like lithology and mineral composition, organic carbon content, lithomechanical property and abnormal pressure, and they preliminarily explored the correlation between the shale macrofractures and the gas-bearing potential [2,3].

Fracture pore refers to intergranular pore in open-shaped high-angle fractures, bedding fractures and well-connected microfissures with a length of several micrometers to tens of micrometers in the shale. The rock permeability is good in the shale interval with fracture pore developed, with permeability generally exceeding 0.01 mD, but it is poor in the matrix pore type shale interval, with permeability generally smaller than 0.01 mD, or even 2–4 magnitude orders smaller than the former [13,14]. The fracture pore origin consists of tectonic activity, organic hydrocarbon generation and diagenesis, and is mostly dominated by tectonic origin. Fracture pores are vital accumulating and seeping space of high-quality shale gas reservoirs, and the identification and quantitative evaluation on it is the fundamental work in selecting shale gas province and studying gas enrichment mechanism [12,17]. Because shale gas exploration and development started late in China, geophysical prediction technique for shale fractures is still at a research and development stage; natural fracture identification, description and evaluation are mainly restricted to visual inspection description and imaging log interpretation on macrofractures (with a width of more than 0.1 mm) and microscopic observation on microfractures [2,3,12–14,17], substantive progress has not yet been made in quantitative evaluation on fractures, and breakthroughs have rarely been reported.

2. Present situation of fracture pore characterization

Fracture pore characterization is an important part of shale reservoir space characterization. Therefore, the main methods for shale pore characterization are often applied in fracture pore identification and evaluation. The technical means like high-precision electron microscope, constant rate mercury injection, helium, nuclear magnetic resonance and geostatistics that are often used for multiscale description of the pore sizes and connectivities, measurement of parameters like porosity and permeability and qualitative judgment of pore types are the routine methods for shale pore characterization [12,17,18], and they are also generally applied in fracture pore characterization.

The high-precision electron microscope technique (with observation accuracy up to 0.04 nm) is suitable for describing nanometer-level microfractures [12,17] and judging pore types. It is often applied in visually observing the length, width and filling status of microfractures and calculating the fracture density. However, affected by such factors as sampling point and field of view, fracture pore volume and porosity cannot be quantitatively calculated.

Constant rate mercury injection and helium methods are mainly used to measure the porosity and permeability of shale samples [12,17]. Depending on porosity and permeability measured, the pore type can be qualitatively judged. Therefore, these two methods are often applied to identify the open microfractures, but they cannot be used to calculate the fracture porosity and have high requirements for sample size.

Nuclear magnetic resonance porosity method, a new technique developed in recent years, is used to quickly measure the porosity and permeability of rocks. Theoretically, the positive correlation between the nuclear magnetic resonance signal of hydrogen atom in the porous fluid of rock samples and the pore volume is used to measure the petrophysics, and then directly judge the pore and fracture type of rocks. This method has low requirement for sample size, and can be used to qualitatively identify the open microfractures and judge the pore types. However, it still cannot be used to calculate the fracture porosity.

Geostatistical analysis method can be used to quantitatively study the shale pore type, origin, development scale, influential factor and evolutionary trend. It is an important way and development trend of quantitative characterization of reservoir space. This method usually uses the data like outcrop, drill core, logging data and experimental test to build various relational charts and mathematical and physical models to reveal the correlation between the reservoir space and various geological factors [12]. With the geostatistical analysis method, we have realized quantitative characterization of matrix pore in the Lower Silurian Longmaxi Fm shale of the Southern Sichuan Basin, and revealed the reservoir space constitution and its longitudinal variation trend of major shale gas pay zones in China [12], providing scientific bases for studying the shale gas accumulation mechanisms. These results would have important reference significance to conducting quantitative characterization of fracture pores.

Fracture porosity or fracture pore volume is a key index to quantitatively evaluate the development of fractures and enrichment and high yield of shale gas pay zones. Its quantitative calculation has become the focus and difficulty of shale gas reservoir evaluation. In this paper, based on the drilling data of Lower Silurian Longmaxi Fm (containing Upper Ordovician Wufeng Fm) in the Fuling gas field of Eastern Sichuan Basin and Changning gas province of Southern Sichuan Basin (Fig. 1), the geostatistical analysis method was used to build a fracture pore prediction model. Furthermore, based on the experimental test data like shale rock minerals, *TOC* and helium porosity, fracture porosity interpretation was conducted on the organic-rich shale intervals (i.e., shale interval with *TOC*>2%, similarly hereinafter) of the above-mentioned gas fields. Thus, the marine shale gas reservoir type and enrichment and high yield pattern in the Sichuan Basin can be revealed. In addition, we have improved the basic procedure and method for quantitatively characterizing the marine shale reservoir space [12], which can provide technical support for the evaluation of shale gas core area.

3. Fracture pore interpretation model

Marine shale is a dual-porosity reservoir composed of matrix pores and fractures. The matrix pore is the major part of shale reservoir space [12]. The fracture pore volume can be determined after the matrix pore volume derived with relevant model and parameters is deducted from the total pore volume. Obviously, it is an effective method of realizing quantitative evaluation of fracture pores to build a dual porosity interpretation model and convert the calculation of fracture pore into the quantitative characterization of matrix pore.

The matrix pore is composed of micropores in brittle minerals, organic micropores and intercrystal micropores of clay minerals [12,18], and the quantitative characterization of them mainly reflects the contribution of brittle minerals (quartz, feldspar and carbonate minerals), organic matters and clay minerals to the reservoir space. Given the combination of aforesaid three types of pores, taking the shale rock density and the mass percentage and pore volume of brittle minerals, clay minerals and organic matters as the basic parameters, we built a mathematical model for quantitative interpretation of matrix pores [12], and realized the effective calculation of matrix porosity and its constitution. The process has been widely used in petroleum industry [15,16,18], and laid a solid foundation for building the porosity interpretation model for dual-porosity reservoirs. The quantitative characterization of matrix pores is detailed in Refs. [12,18], which will be omitted here. The porosity interpretation model for dual-porosity reservoirs newly built will be introduced as follows.

Firstly, a 3-layer petrophysical model in which the shale matrix pores occur [12] was introduced. The three layers include a brittle mineral layer (quartz, feldspar and carbonate minerals, containing micropores in brittle minerals), an organic layer (containing organic micropores) and a clay mineral layer (containing intercrystal micropores of clay minerals) [12]. On the basis of this model, a fracture pore layer was added. Thus, the petrophysical model for marine shale dual-porosity reservoirs was built (Fig. 2).

Then, based on the petrophysical model for dual-porosity reservoir shown in Fig. 2, the mathematical model for porosity in dual-porosity reservoir was built as follows:

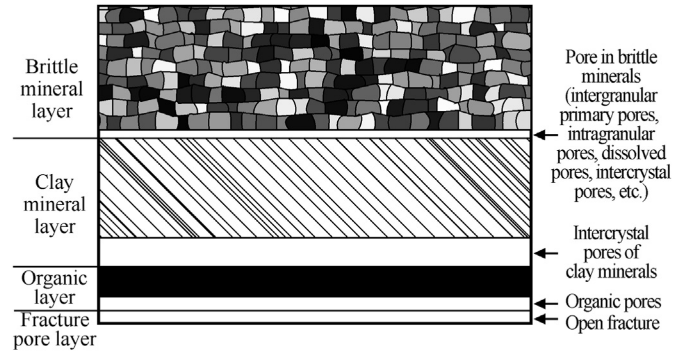

Fig. 2. The petrophysical model for marine shale dual-porosity reservoirs. (modified from Ref. [12]).

$$\varphi_{\mathrm{Total}} = \varphi_{\mathrm{Matrix}} + \varphi_{\mathrm{Frac}} \tag{1}$$

$$\varphi_{\mathrm{Matrix}} = \rho A_{\mathrm{Bri}} V_{\mathrm{Bri}} + \rho A_{\mathrm{Clay}} V_{\mathrm{Clay}} + \rho \mathrm{A}_{\mathrm{TOC}} V_{\mathrm{TOC}} \tag{2}$$

Eq. (1) is the theoretical model for porosity calculation of dual-porosity reservoirs, where, φ_{Total} is the total porosity of shale, generally obtained by helium experimental test; $\varphi_{\mathrm{Matrix}}$ is the matrix porosity of shale, obtained by Eq. (2); φ_{Frac} is the fracture porosity of shale, obtained by subtracting $\varphi_{\mathrm{Matrix}}$ from φ_{Total}. Therefore, the calculation of $\varphi_{\mathrm{Matrix}}$ is the basis and key to the prediction of the model.

Eq. (2) is the matrix pore prediction model [12,18], where, ρ represents shale rock density, t/m^3; A_{Bri}, A_{Clay} and A_{TOC} represent the mass percentages of brittle mineral, clay mineral and organic matter respectively; V_{Bri}, V_{Clay} and V_{TOC} represent the micropore volumes per unit mass of brittle mineral, clay mineral and organic matter respectively, m^3/t, i.e., the contribution of unit mass of them to the pore volumes, and they are the key parameters per the model. Calibration calculation should be conducted by selecting the data points where fractures are not developed in the assessment area. Regarding the features and value methods of the relevant parameters in Eq. (2), refer to Refs. [12,18] in the paper.

4. Calibration calculation and verification of key parameters

4.1. Calibration calculation of key parameters

Regarding V_{Bri}, V_{Clay} and V_{TOC} on matrix porosity computation model for the Longmaxi Fm in the Sichuan Basin, The data of Well CX 1 was used to conduct calibration calculation for the Changning gas province, and three key parameters were determined as 0.0079 m^3/t, 0.039 m^3/t and 0.138 m^3/t respectively [12]. In the paper, calibration calculation and inspection of the above three parameters in the Fuling gas field in Chongqing region were introduced.

A number of appraisal wells like JY 1, JY 2, JY 3 and JY 4 have been drilled in Fuling gas field, and the geologic data like rock-mineral, organic abundance and physical property are complete [13—16,19—22]. Therefore, this gas field has the favorable conditions for quantitative characterization of shale

Table 1
Parameters of 3 sampling points in the Longmaxi Fm of Well JY 1.

Depths of 3 sampling points/m	Basic data					Micropore volume per unit mass/($m^3 \cdot t^{-1}$)		
	Quartz + feldspar + calcareous content	Clay mineral content	Organic content	Porosity	Rock density/($g \cdot cm^{-3}$)	V_{Bri}	V_{Clay}	V_{TOC}
2336.7	37%	61.60%	0.59%	4.92%	2.65	0.0061	0.025	0.17
2381.9	53%	43.59%	3.05%	4.98%	2.58			
2404.6	63%	33.93%	4.46%	4.88%	2.45			

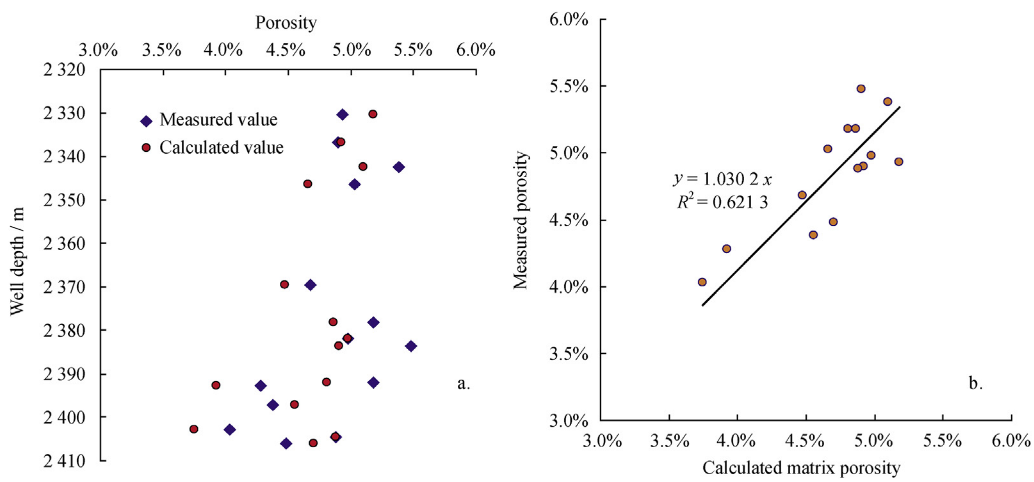

Fig. 3. Correlation of the calculated and measured matrix porosity of the Longmaxi Fm in Well JY 1.

gas reservoir space (Fig. 1). The porosity distribution feature of Longmaxi Fm in Well JY 1 is similar to that in Changning gas province, with permeability usually smaller than 0.01 mD [13,14] and fracture pore underdeveloped, so this well can be taken as the data point for calibrating V_{Bri}, V_{Clay} and V_{TOC}. Wells JY 2 and JY 4 exhibit high porosity and high permeability feature, with permeability generally more than 0.1 mD [19] and fracture pore developed; they are not suitable to be taken as the data points for calibrating key parameters of matrix pore.

In this paper, three black shale data points were selected at 2336.7 m, 2381.9 m and 2404.6 m in Well JY 1 (corresponding to 0.6%, 3.1% and 4.5% *TOC* respectively) for calibrating V_{Bri}, V_{Clay} and V_{TOC} with Eq. (2) (Table 1). The V_{Bri}, V_{Clay} and V_{TOC} values were calculated to be 0.0061 m^3/t, 0.025 m^3/t and 0.17 m^3/t respectively (Table 1), and they are basically the same as the values corresponded by the Changning gas province. This indicates that the pore volumes of brittle minerals, clay minerals and organic matters as well as the matrix pore volume of the Longmaxi Fm in the Sichuan Basin are kept stable in the region.

4.2. Verification of calculation results

Based on the above calculation results and the rock mineral test data, matrix porosity estimation was conducted on 14 data points in depth intervals of 2378–2407 m and 2330–2347 m in Well JY 1 (10 data points in the depth interval of 2378–2407 m, and 4 in that of 2330–2347 m). Then, correlation was conducted between the calculated porosities and the measured porosities of these depth points (Fig. 3-a), so as to check whether the selection of the three data points and the calculated values of V_{Bri}, V_{Clay} and V_{TOC} are rational. The correlation results show that the calculated porosities of the 14 depth points tally with the measured porosities, and there is a good linear relationship between them (Fig. 3-b). It thereby is confirmed that the three selected calibration points and the V_{Bri}, V_{Clay} and V_{TOC} calculated values are in conformance with the actual geological setting of the Longmaxi Fm shale reservoir space in the Fuling gas field, and that they can be taken as the effective geologic bases for predicting the matrix pore and its constitution in this field.

5. Calculation of fracture porosity

In the paper, based on the test data of rock minerals and helium porosities and the V_{Bri}, V_{Clay} and V_{TOC} calculated values of Longmaxi Fm in the Fuling and Changning gas fields, the mathematical model for porosity in dual-porosity reservoirs was used to conduct fracture porosity estimation on the 19 depth points in 2537.38–2590.24 m interval in Well JY 4 and 31 depth points in 2330.4–2414.9 m interval in Well JY 1 of the Fuling gas field as well as the 30 depth points in 100–153 m interval in Well CX 1 of the Changning gas province respectively, with the estimated results shown in Table 2 and Figs. 4–6.

In 2537.38–2590.24 m interval in Well JY 4 (*TOC* of 1.0%–6.0%, or 2.9% averagely), total porosity ranges in

Table 2
Porosity constitution estimation of Wufeng Fm − Longmaxi Fm in Wells JY 4, JY 1 and CX 1.

Main parameters		Well JY 4	Well JY 1	Well CX 1	Data source
Depth interval for estimation/m		2537.38−2590.24	2330.4−2414.9	100−153	
TOC		1.0%−6.0%/2.9% (19)	0.7%−4.7%/2.6% (31)	1.3%−5.4%/3.3% (30)	
Total porosity		4.6%−7.8%/5.8% (19)	3.7%−7.0%/4.9% (31)	3.4%−8.4%/5.5% (30)	Refs. [12−16,19−22]
Matrix porosity	Subtotal	3.7%−5.2%/4.6% (19)	3.7%−5.6%/4.6% (31)	3.4%−8.2%/5.4% (30)	
	Organic porosity	0.6%−2.0%/1.3% (19)	0.3%−2.0%/1.1% (31)	0.4%−1.9%/1.2% (30)	
	Intercrystal porosity of clay minerals	1.2%−3.6%/2.4% (19)	1.2%−4.1%/2.6% (31)	0.8%−5.6%/3.0% (30)	
	Porosity of brittle minerals	0.6%−1.2%/0.9% (19)	0.5%−1.2%/0.9% (31)	0.7%−1.7%/1.2% (30)	
Fracture porosity		0.3%−3.3%/1.3% (19)	0−2.4%/0.3% (31)	0−1.2%/0.1% (30)	
Permeability/mD		0.05−0.30/0.15 (19)	0.0017−0.5451/0.058 (10)	0.00022−0.00190/0.00029 (11)	Refs. [12−16,19−22]

Note: The value interval in the table is expressed as minimum value − maximum value/mean value (number of sampling depth points).

4.6%−7.8% (5.8% averagely). Specifically, the matrix porosity ranges in 3.7%−5.2% (4.6% averagely), and the fracture porosity ranges in 0.3%−3.3% (1.3% averagely) (Table 2, Fig. 4). In the constitution of matrix porosity, the organic porosity ranges in 0.6%−2.0% (1.3% averagely), the intercrystal porosity of clay minerals ranges in 1.2%−3.6% (2.4% averagely), and the porosity of brittle minerals ranges in 0.6%−1.2% (0.9% averagely). The fracture pores are distributed at 18 depth points below 2540.34 m, with porosity increasing from top to bottom, i.e., increasing from 0.3% at 2540.34 m to 3.3% at 2590.24 m, whereas in the 20 m-interval (2570.89−2590.24 m) at the bottom, the porosity ranges in 1.1%−3.3% (1.9% averagely). The experimental test shows that the vertical permeability of the 18 depth points in the fracture-developed interval ranges in 0.05−0.30 mD (0.15 mD averagely). This indicates that the depth interval below 2540 m is where fractures and pores intensively developed with good vertical permeability, basically in a vertically connected state,

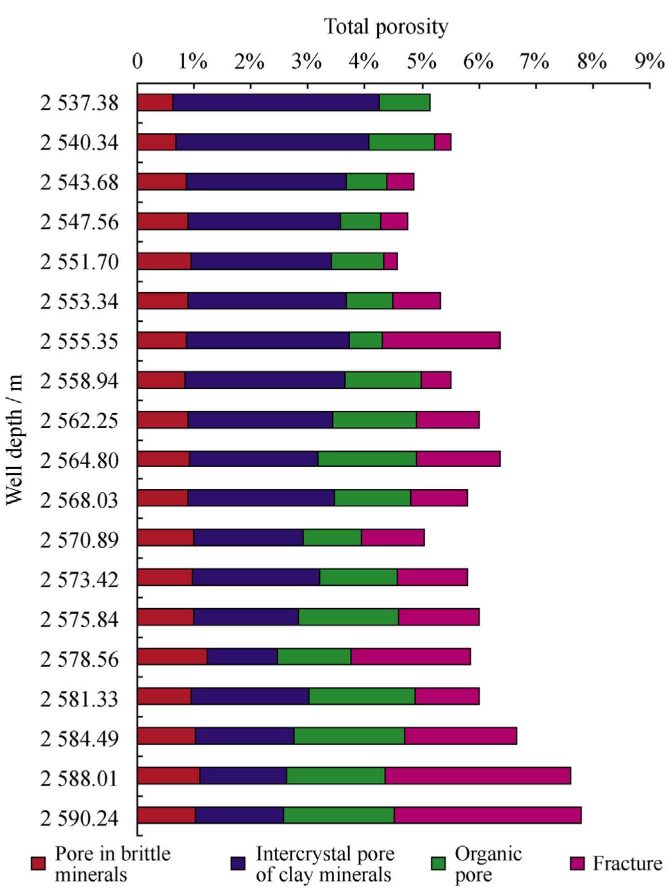

Fig. 4. Total porosity constitution of Wufeng Fm − Longmaxi Fm organic-rich shale interval in Well JY 4.

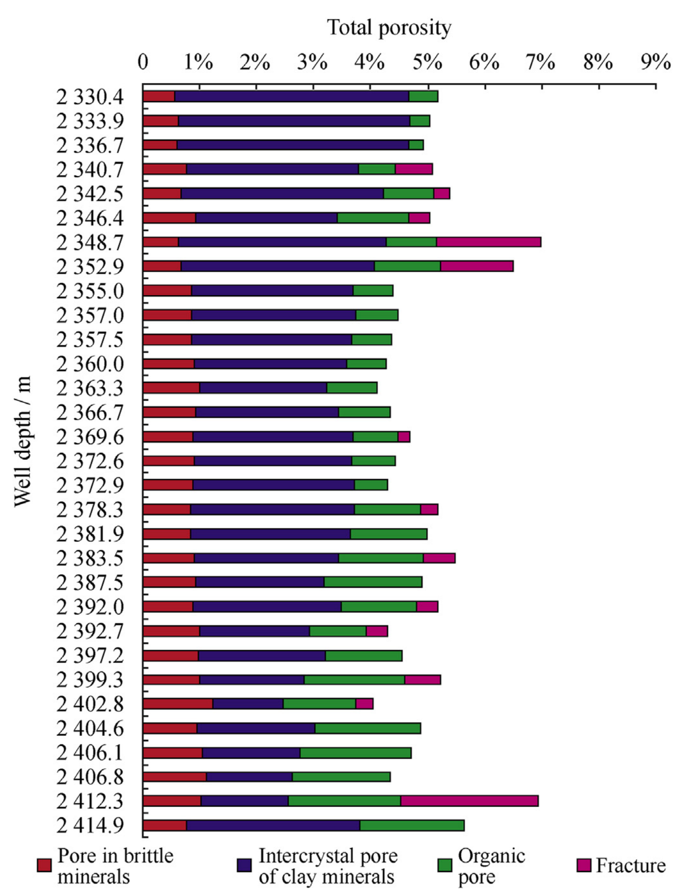

Fig. 5. Total porosity constitution of Wufeng Fm − Longmaxi Fm organic-rich shale interval in Well JY 1.

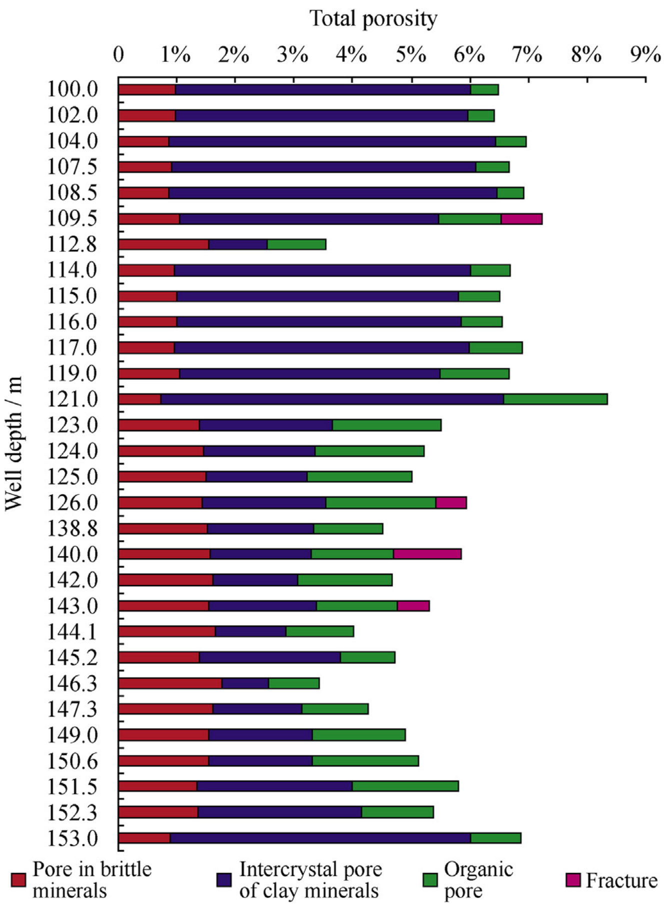

Fig. 6. Total porosity constitution of Wufeng Fm – Longmaxi Fm organic-rich shale interval in Well CX 1.

and the concentrated interval thickness exceeding 60 m, far thicker than the organic-rich shale interval (thickness of 39.5 m) at the bottom; the fracture porosity increases towards the bottom to max. 3.3% in Wufeng Fm (2590.24 m), showing that the facture longitudinal development feature is related to the detachment metamorphosis at the bottom of Wufeng Fm – Longmaxi Fm [14]. Obviously, the shale gas pay zone is no longer restricted to the organic-rich shale interval in this wellblock, but rather has been expanded to the whole fracture pore developed interval, and the contribution of Wufeng Fm to the shale gas productivity is prominent.

In 2330.4–2414.9 m interval in Well JY 1 (*TOC* of 0.7%–4.7%, or 2.6% averagely), the total porosity ranges in 3.7%–7.0% (4.9% averagely). Specifically, the matrix porosity ranges in 3.7%–5.6% (4.6% averagely), and the fracture porosity ranges in 0–2.4% (0.3% averagely) (Table 2, Fig. 5). In the constitution of matrix porosity, the organic porosity ranges in 0.3%–2.0% (1.1% averagely), the intercrystal porosity of clay minerals ranges in 1.2%–4.1% (2.6% averagely), and the porosity of brittle minerals ranges in 0.5%–1.2% (0.9% averagely). Fracture pore is only distributed at some depth points like 2340–2353 m, 2378.3 m, 2383.5 m, 2399.3 m and 2412.3 m, and the mean value of fracture porosity is only 0.35% in the organic-rich shale interval (2378.3–2414.9 m) at the bottom. This indicates that the fracture pore of Wufeng Fm – Longmaxi Fm shale in Wellblock JY 1 is underdeveloped, with the pore type dominated by matrix pores and microfractures developed only in some depth points.

Well CX 1 is a data well located in the northern slope of Changning structure [11,12]. In 100–153 m interval (*TOC* of 1.3%–5.4%, or 3.3% averagely), the total porosity ranges in 3.4%–8.4% (5.5% averagely). Specifically, the matrix porosity ranges in 3.4%–8.2% (5.4% averagely), and the fracture porosity ranges in 0–1.2% (0.1% averagely) (Table 2, Fig. 6). In the constitution of matrix porosity, the organic porosity ranges in 0.4%–1.9% (1.2% averagely), the intercrystal porosity of clay minerals ranges in 0.8%–5.6% (3.0% averagely), and the porosity of brittle minerals ranges in 0.7%–1.7% (1.2% averagely). The fracture pores are only distributed at 4 depth points like 109.5 m, 126 m, 140 m and 143 m, i.e., relatively developed at top Wufeng Fm – bottom Longmaxi Fm (126–143 m interval), and basically underdeveloped at other depth points. This indicates that fracture pore is underdeveloped in the Wufeng Fm – Longmaxi Fm in the slope zone of the Changning structure with the pore type dominated by matrix pores.

Based on the interpretation on matrix porosity and fracture porosity in organic-rich shale intervals in Wells JY 4, JY 1 and CX 1, it is discovered that the matrix porosity of Wufeng Fm – Longmaxi Fm shale is basically the same in Eastern Sichuan Basin and Southern Sichuan Basin, ranging in 4.6%–5.4%, and is similar to that of Barnett shale [4,20,23,24]. Furthermore, the organic porosity, intercrystal porosity of clay minerals and porosity of brittle minerals have little regional variation; while the fracture porosity, affected by various factors like rock brittleness, regional stress field and tectonic activity strength, is largely different in different tectonic provinces and different wellblocks and intervals of the same structure, showing a very strong heterogeneity of fracture development in marine shale. Generally, the fracture pore in the organic-rich shale interval of the Fuling gas field is more developed than that of Changning gas province.

6. Gas reservoir type

The development level and distribution pattern of fracture pore is not only one of the key controlling factors for the shale gas enrichment and high yield, but also the focus in shale gas geological evaluation. Judged from the development level of fracture pore in Wells JY4, JY 1 and CX 1, the Wufeng Fm – Longmaxi Fm have two shale gas reservoir types like matrix pore + fracture pore and matrix pore, i.e., two enrichment and high yield patterns (Table 3).

6.1. A matrix pore + fracture pore shale gas reservoir

This type of gas reservoir generally has outstanding features like special tectonic setting, high fracture porosity, good permeability, high free gas content, large pay thickness and high horizontal well output (Table 3), e.g., wellblocks JY 4 and JY 2 in the Fuling gas field (Table 3). In most of the wellblocks of the Fuling gas field, the net pay thickness of

Table 3
Geologic parameter correlation of two types of gas reservoirs of Wufeng Fm − Longmaxi Fm.

	Gas reservoir type	Matrix pore	Matrix pore + fracture pore	Data source
	Structural setting	Broad slope and syncline	Box-like, comb-type anticline	Refs. [11–14]
	Pore type	Dominated by matrix pores, with a few fractures	Matrix pores and fracture pores	
Physical properties	Total porosity	3.4%–8.4%/5.5%	4.6%–7.8%/5.8%	Refs. [19–21]
	Fracture porosity	0–1.2%/0.1%	0.3%–3.3%/1.3%	
	Permeability/mD	0.00022–0.00190/0.00029	0.05–0.30/0.15	
	Typical cases	Most wellblocks in the Changning and Weiyuan gas fields	Wellblocks JY 4 and JY 2 in the Fuling gas field	Refs. [19–22]

Note: the value interval in the table is expressed as minimum value − maximum value/mean value.

Wufeng Fm − Longmaxi Fm exceeds 60 m (more than the organic-rich shale thickness of 38–44 m), the average fracture porosity is 1.3% (1.9% in 20 m "sweet spot" interval at the bottom, far higher than the 0.8%–1.0% of Barnett shale); the average permeability is 0.15 mD; the average test gas content is 6.1 m^3/t (compared with Barnett shale, the free gas content is speculated as possibly up to 80%); and the test output of horizontal well is (5.90–54.73) × 10^4 m^3/d (36.42 × 10^4 m^3/d averagely). The fracture initiation mechanism of this type of shale gas reservoir is related to a special tectonic setting [13,14]. Based on the study of Guo Tonglou and Zhang Hanrong, the Fuling gas field was confirmed to be a high-yield one that had been inverted at late stage and has a special box-like anticlinal structure with the formation of fractures being originated from the coaction of the two NE and SN trend fault systems in the region and the detachment layer at the bottom of Wufeng Fm − Longmaxi Fm [13,14], and a wide range of mutually connected reticular fractures developed in the pay zone. Based on which, it is inferred that the comb-type anticlinal zones located in Southern Sichuan Basin, Eastern Sichuan Basin and around the Basin are the favorable areas for the development of matrix pore + fracture pore shale gas reservoirs, but the distribution range of them is possibly relatively restricted.

6.2. A matrix pore shale gas reservoir

Reservoir spaces are dominated by matrix pores, and this type of gas reservoir generally has the prominent features like undeveloped fracture pore, low permeability, moderate high free gas content and moderate high horizontal well output (Table 3), e.g., most wellblocks in the Changning and Weiyuan gas fields. Exploration and research achievements confirm that the Changning gas province is mostly located in a broad slope − synclinal area, showing the feature of a widely-distributed matrix pore shale gas reservoir. In most well-blocks, the average matrix porosity is 5.4%; the average fracture porosity is 0.1%; the permeability ranges in 0.00022–0.00190 mD (0.00029 mD averagely); the pay zone is controlled by the organic-rich shale concentrated interval with the thickness ranging in 33–46 m; the average test gas content is 4.1 m^3/t (the average free gas content being 60%); and the horizontal well test output ranges in 5.55 × 10^4–27.40 × 10^4 m^3/d (13.46 × 10^4 m^3/d averagely, corresponding to 37% in the Fuling gas field). Exploration practices confirm that matrix pore shale gas reservoirs are widely distributed in slope zones and synclinal zones of the Sichuan Basin, predominating in the marine shale gas distribution area, so they might be the main areas for marine shale gas exploration in southern China.

7. Conclusions

Through interpretation and assessment on fracture pores in three wells of the Fuling and Changning gas provinces, a set of effective methods for quantitative characterization of marine shale reservoir space have preliminarily been formed, and the main shale gas reservoir types of Wufeng Fm − Longmaxi Fm in the Sichuan Basin have been revealed.

1) The calculation of fracture porosity can be converted into the quantitative characterization of matrix porosity using the dual-porosity interpretation model. This is an effective method for realizing quantitative evaluation of shale fracture pores, and also an enrichment and development to the quantitative characterization technique of marine shale reservoir space.
2) The matrix pore volume and its constitution of Wufeng Fm − Longmaxi Fm pay zones have a stable regional distribution. In the gas provinces of Eastern Sichuan Basin and Southern Sichuan Basin, the matrix porosity ranges in 4.6%–5.4%, and the porosity of brittle minerals, intercrystal porosity of clay minerals and organic porosity have a little change in horizontal direction.
3) The developmental features of fracture pores in Wufeng Fm − Longmaxi Fm are largely different in tectonic provinces of Eastern Sichuan Basin − Southern Sichuan Basin and wellblocks and intervals of the same structure, showing a very strong heterogeneity of reservoir permeability conditions of marine shale.
4) There are two shale gas reservoir types like matrix pore + fracture pore and matrix pore in Wufeng Fm − Longmaxi Fm of the Sichuan Basin. The matrix pore + fracture pore shale gas reservoirs are mainly developed in the area with a special tectonic setting with characteristics of developed fracture pores, large gas

content, high free gas content, thick pay zones and high single well output, and its distribution range may be relatively restricted in the Sichuan Basin. The matrix pore shale gas reservoir has the features like high matrix porosity, underdeveloped fracture pore and moderate-high single well output. These reservoirs are widely developed in the slope zones and synclinal zones of the Sichuan Basin and predicted to be predominating in the marine shale gas distribution areas.

References

[1] Li Xinjing, Hu Suyun, Cheng Keming. Suggestions from the development of fractured shale gas in North America. Petroleum Explor Dev 2007;34(4):392−400.

[2] Ding Wenlong, Li Chao, Li Chunyan, Xu Changchun, Jiu Kai, Zeng Weite. Dominant factor of fracture development in shale and its relationship to gas accumulation. Earth Sci Front 2012;19(2):212−20.

[3] Nie Haikuan, Bian Ruikang, Zhang Peixian, Gao Bo. Micro-types and characteristics of shale reservoir of the lower Paleozoic in Southeast Sichuan Basin, and their effects on the gas content. Earth Sci Front 2014;21(4):331−43.

[4] Writing Group of Shale Gas Geological Exploration and Development Practices Books. Exploration and development progress of shale gas in North America. Beijing: Petroleum Industry Press; 2009.

[5] Bowker KA. Barnett shale gas production, Fort Worth Basin: issues and discussion. AAPG Bull 2007;91(4):523−33.

[6] Gale JFW, Reed RM, Holder J. Natural fractures in the Barnett shale and their importance for hydraulic fracture treatments. AAPG Bull 2007;91(4):603−22.

[7] Jenkins C, Ouenes A, Zellou A, Wingard J. Quantifying and predicting naturally fractured reservoir behavior with continuous fracture models. AAPG Bull 2009;93(11):1597−608.

[8] Curtis JB. Fractured shale-gas systems. AAPG Bull 2002;86(11):1921−38.

[9] Dong Dazhong, Zou Caineng, Li Jianzhong, Wang Shejiao, Li Xinjing, Wang Yuman, et al. Resource potential, exploration and development prospect of shale gas in the whole world. Geol Bull China 2011;31(2):324−36.

[10] Wang Yuman, Dong Dazhong, Li Xinjing, Huang Jinliang, Wang Shufang, Wu Wei. Stratigraphic sequence and sedimentary characteristics of lower Silurian Longmaxi formation in the Sichuan Basin and its peripheral areas. Nat Gas Ind 2015;35(3):12−21.

[11] Wang Yuman, Dong Dazhong, Li Jianzhong, Wang Shejiao, Li Xinjing, Wang Li, et al. Reservoir characteristics of shale gas in Longmaxi formation of the lower Silurian, southern Sichuan. Acta Pet Sin 2012;33(4):551−61.

[12] Wang Yuman, Dong Dazhong, Yang Hua, He Ling, Wang Shiqian, Huang Jinliang, et al. Quantitative characterization of reservoir space in the lower Silurian Longmaxi Shale, southern Sichuan, China. Sci China Earth Sci 2014;44(6):1348−56.

[13] Guo Tonglou, Liu Ruobing. Implications from marine shale gas exploration breakthrough in complicated structural area at high thermal stage: taking Longmaxi Formation in well JY 1 as an example. Nat Gas Geosci 2013;24(4):643−51.

[14] Guo Tonglou, Zhang Hanrong. Formation and enrichment mode of Jiaoshiba shale gas field, Sichuan Basin. Petroleum Explor Dev 2014;41(1):28−35.

[15] Guo Xusheng, Li Yuping, Liu Ruobing, Wang Qingbo. Characteristics and controlling factors of micro-pore structures of Longmaxi Shale Play in the Jiaoshiba area, Sichuan Basin. Nat Gas Ind 2014;34(6): 9−16.

[16] Wei Zhihong, Wei Xiangfeng. Comparison of gas-bearing property between different pore types of shale: a case from the Upper Ordovician Wufeng and Longmaxi Fms in the Jiaoshiba area, Sichuan Basin. Nat Gas Ind 2014;34(6):37−41.

[17] Zou Caineng, Zhu Rukai, Bai Bin, Yang Zhi, Wu Songtao, Su Ling, et al. First discovery of nano-pore throat in oil and gas reservoir in China and its scientific value. Acta Petrol Sin 2011;27(6):1857−64.

[18] Wang Daofu, Wang Yuman, Dong Dazhong, Wang Shiqian, Huang Jinliang, Huang Yongbin, et al. Quantitative characterization of reservoir space in the lower Cambrian Qiongzhusi Shale, Southern Sichuan Basin. Nat Gas Ind 2013;33(7):1−10.

[19] Hu Dongfeng, Zhang Hanrong, Ni Kai, Yu Guangchun. Main controlling factors for gas preservation conditions of marine shales in southeastern margins of the Sichuan Basin. Nat Gas Ind 2014;34(6):17−23.

[20] Zou Caineng, Yang Zhi, Zhang Guosheng, Hou Lianhua, Zhu Rukai, Tao Shizhen, et al. Conventional and unconventional petroleum “orderly accumulation”: concept and practical significance. Petroleum Explor Dev 2014;41(1):14−27.

[21] Zheng Herong, Gao Bo, Peng Yongmin, Nie Haikuan, Yang Feiran. Sedimentary evolution and shale gas exploration direction of the Lower Silurian in Middle−Upper Yangtze area. J Palaeogeogr 2013;15(5):645−56.

[22] Hu Weiguang, Liu Zhujiang, Fan Chunhua, Zhou Zhuozhu, Li Chunyan. Seismic prediction and evaluation of fractures in Silurian Longmaxi Shale at J area in Sichuan Basin. Mar Orig Pet Geol 2014;19(4):25−30.

[23] Dong Bingxiang, Cheng Yuanfang, Liu Yuchuan, Yi Xinbin, Yang Liu, Wu Lingyan, et al. Research of the petrophysical property of shale gas reservoirs. J Xi'an Shiyou Univ Nat Sci Ed 2013;28(1):25−8.

[24] Hou Dujie, Bao Shujing, Mao Xiaoping, Chen Xinjun, Ma Ning, Zhang Xiaotao, et al. Discussion on the key issues of resource potential evaluation for shale gas. J Earth Sci Environ 2012;34(3):7−16.