



# A New Fracability Evaluation Approach for Shale Reservoirs Based on Multivariate Analysis: A Case Study in Zhaotong Shale Gas Demonstration Zone in Sichuan, China

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**Abstract:** Fracability characterizes the effectiveness of hydraulic fracturing. The existing assessment methods cannot reflect the actual value of the effectiveness due to a lack of comprehensive consideration and neglect of the influences of engineering factors. This study aims to solve this problem by implementing geological static data and production dynamic data in multivariate analysis in Zhaotong shale gas demonstration zone. First, the reservoir quality index (RQI) was introduced to evaluate the exploration potential by integrating the geological parameters with gray relational analysis. Moreover, the differences in fracturing fluid types and proppant sizes were considered, and the operating parameters were normalized on the basis of the equivalence principle. Finally, the general reservoir fracability index (GRFI) was proposed based on a dimensioned processing of the various parameters. A case study was conducted to verify the accuracy and feasibility of this new approach. The results demonstrate that (1) the organic carbon and gas content are adjusted to contribute the most to the calculation of the RQI, while the effective porosity contributes the least; (2) the fracturing scale is the main operating parameter determining the fracability, which has the strongest correlation with the effectiveness of fracking; and (3) the GRFI has a positive correlation with shale gas production, and the lower limit of the GRFI of 2,000 corresponds to a daily production of 50,000 m<sup>3</sup>/d; this value is defined as the threshold value of a stripper well. The GRFI is consistent with the productivity trend of shale gas wells in the research block, which suggests that the new model is accurate and practical for well candidate selection.

**Key words:** fracability, multivariate analysis, equivalence principle, network fracturing, shale gas

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## 1 Introduction

Shale gas has been a hot field of study in oil and gas exploration worldwide. Due to the combined technologies of horizontal drilling and multistaged fracturing, shale gas exploitation has boomed in the United States (Hughes, 2013; Zou Caineng et al., 2016). According to the British Petroleum (BP) Statistical Review of World Energy 2017 (Mckay, 2017), by 2016, American natural gas production had reached  $7.49 \times 10^{11}$  m<sup>3</sup>, among which unconventional natural gas production had far exceeded conventional production. China is a late starter in shale gas exploitation; however, with  $80.21 \times 10^{12}$  m<sup>3</sup> of geological shale reserves and  $12.85 \times 10^{12}$  m<sup>3</sup> of recoverable shale reserves, it has great potential for exploiting shale gas. More than 90% of

shale gas wells can only be produced by hydraulic fracturing because of the low porosity and low permeability (Zou Caineng et al., 2016). The fracability, which is defined as the ease of fracturing to form a complex fracture network, has a close relationship with the effects of reservoir stimulation (Li Gensheng et al., 2016; Chen Mian et al., 2017). Therefore, further study on fracability evaluation is important for screening wells and layers, optimizing fracturing design and forecasting economic benefits.

The fracability index (FI) has been introduced to characterize the capability of shale gas reservoirs to effectively have hydraulic fracturing and producing complex fractures carried out (Chong et al., 2010). Currently, the brittleness index (BI), which is represented by the ratio of the brittle mineral content to the total mineral content, is normally used for fracability evaluation

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by many scholars (Jarvie et al., 2007). Based on the clay content analysis of Barnett shale reservoirs, a conclusion was reached that a higher BI indicates a richer quartz and calcite content, which suggests that more natural fractures can be created and a higher porosity can be expected (Mayerhofer et al., 2010). Rickman proposed another BI formula with the dynamic Poisson's ratio and Young's modulus based on logging data. It is easy to generate complex fractures in brittle rocks with a higher Young's modulus and a lower Poisson's ratio (Rickman et al., 2008). However, the BI obtained by this approach can reflect only the mean value in a research area; for those strongly anisotropic shale plays, the BI has obvious limitations in reflecting the formation fracability. To overcome the shortcomings of the BI, Jin presented a new method to quantify the FI by integrating both the brittleness and energy dissipation during hydraulic fracturing (Jin et al., 2015). With a combination of uniaxial compressive tests and fracture mechanics, a FI prediction model was specifically designed for the shales of the Lower Silurian Longmaxi Formation in Sichuan Basin, China, based on mechanical parameters. A positive correlation was found between the FI and BI (Yuan et al., 2017). With the proper stimulation treatment parameters considered, Liu proposed a new method to evaluate the fracability based on operating parameters (Liu et al., 2018). After a quantitative analysis of the mineral composition and operating parameters, Wang developed a new model for the continuous fracability evaluation of shale reservoirs by the weight allocation theory (Wang Hanqing et al., 2016).

The above evaluations can be categorized as experimental evaluations and statistical evaluations. Through lab core tests or seismic inversions, constant parameters, including static geologic characteristics and rock mechanical properties, are studied to evaluate the fracability (Altindag, 2009; Yagiz, 2009; Wang et al., 2015; Gholami et al., 2016; Sui et al., 2016). No matter which methodology is used, very few studies take dynamic production data into account, which makes it difficult to represent the fracability in actual fracturing treatments. Thus, it is necessary to develop a comprehensive fracability evaluation method for shale reservoirs. In this paper, both geological and operating parameters influencing the fracability are discussed. A new term, the reservoir quality, is introduced by weighting in geological parameter analysis, while the different operating parameters of horizontal wells are carefully considered in the study. Finally, a comprehensive FI evaluation model is established based on multivariate analysis.

The remainder of this paper is organized as follows. Brief introduction of geological settings in the studied area is introduced in section 2. The geological and operating parameters influencing the fracability are analyzed, and a comprehensive FI evaluation model is set up in Section 3. The new model is applied to Zhaotong shale gas demonstration zone in Sichuan, China, and the results are discussed in Section 4. The conclusions are summarized in Section 5.

## 2 Geological Settings

Zhaotong shale gas demonstration area is located in the Dianqianbei depression of the southern margin in Sichuan Basin. It is characterized by over maturity, strong transformation and complex stress. Huangjinba, Zijingba, Yunshanba and Dazhai blocks are shale gas enrichment regions, covering an area of about  $1.2 \times 10^4 \text{ km}^2$ , as shown in Fig. 1. Organic-rich shale develop in the early transgressive period-regressive deep water shelf facies with the thickness of 30–40m. The discovered gas are mainly from Wufeng-Longmaxi Formation (Chen Fangwen et al., 2018). According to the characteristics of lithology and electricity, the gas-bearing zone can be subdivided into six single layers, Long<sub>1</sub><sup>1</sup>-Long<sub>1</sub><sup>2</sup> has a high TOC, porosity and gas content but with a decreasing trend from bottom to top. The casing part of horizontal well is mainly in the first bed and second bed of member I of Longmaxi Formation.

## 3 Samples and Methods

The geological parameters influencing the fracability should reflect the shale gas potential and physical properties of the reservoir (Guo Tonglou, 2016; Guo Xusheng et al., 2017). Shale gas deposits are unconventional resources that have special sedimentary and structural characteristics (Hammes et al., 2011; He et al., 2017); the total organic carbon (TOC), effective porosity, gas content, BI, and formation pressure coefficient are selected to characterize the fracability in this paper.

### 3.1 Geological parameters

#### 3.1.1 Reservoir quality

First, the gas in shale formations can appear as free gas and adsorbed gas, where the free gas is located in the pores of the formation and the adsorbed gas is within the organic-rich formation. The adsorbed gas accounts for the majority of the gas in shale formations; thus, the TOC determines the shale gas potential. Additionally, the porosity and permeability of the organic matter are better than those of the shale matrix (Guo Tonglou, 2013; Liang Chao et al., 2017). Second, most of the pores in shale reservoirs are micro- and nano pores, and the pore system is complex. To a certain extent, the effective porosity can indicate the complexity of fractures and influence the effectiveness of hydraulic fracturing (Sun et al., 2017). Third, the gas content clearly indicates the exploitation potential of shale reservoirs (Wang Yuman et al., 2014). Since the TOC, effective porosity and gas content can reflect the basic geological features of shale reservoirs, they can be integrated into one parameter, the reservoir quality. Because they are positively correlated with shale gas production and can produce additive effects, the reservoir quality index (RQI) can be expressed as:

$$RQI = (S_1)^{\omega_1} \times (S_2)^{\omega_2} \times (S_3)^{\omega_3} \quad (1)$$

where  $S_1$ ,  $S_2$  and  $S_3$  are the factors influencing the reservoir quality and  $\omega_1$ ,  $\omega_2$  and  $\omega_3$  are their weighting factors, respectively. Relationships between each factor and shale

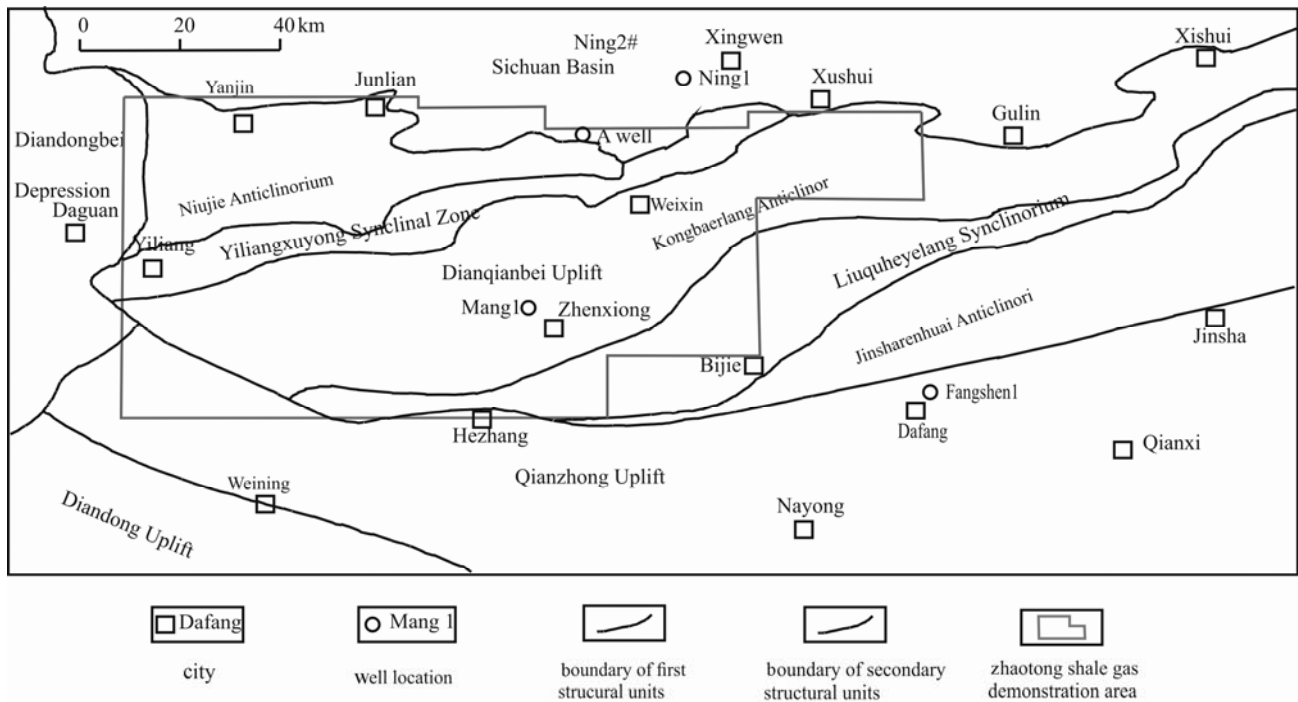


Fig. 1. Geological structure map of study area (Wang Pengwan et al., 2017).

gas production can be developed, and the respective weighting factor can be calculated through gray relational analysis (GRA). The formula shows that a larger RQI indicates better reservoir quality and better fracability.

### 3.1.2 Brittleness

The brittleness, characterizing the ease of fracking, is a key factor in fracability evaluation. The BI is calculated according to the brittle mineral content and mechanical properties. The former is obtained through X-ray diffraction (Jiang Yuqiang et al., 2010). The latter focuses on the analysis of mechanical characteristics by rock mechanics experiments (Cipolla et al., 2010). It is easier for brittle shale to develop complex fracture networks that enhance gas production by connecting fracture fairways to the wellbore via hydraulic fracturing (Zhang et al., 2016). Rickman proposed the BI as a function of the Young's modulus and Poisson's ratio for shale as:

$$E_{BRIT} = (E_c - E_{cmin}) / (E_{cmax} - E_{cmin}) \quad (2)$$

$$v_{BRIT} = (v_c - v_{cmin}) / (v_{cmax} - v_{cmin}) \quad (3)$$

$$BI = \frac{(E_{BRIT} + v_{BRIT})}{2} \quad (4)$$

where  $E_{BRIT}$  is the normalized Young's modulus, dimensionless;  $E_c$  is the dynamic Young's modulus of the investigated formation, dimensionless;  $E_{cmax}$  and  $E_{cmin}$  are the dynamic maximum and minimum Young's modulus of the investigated formation, respectively, dimensionless;  $v_{BRIT}$  is the normalized Poisson's ratio, dimensionless;  $v_c$  is the dynamic Poisson's ratio of the investigated formation, dimensionless; and  $v_{cmax}$  and  $v_{cmin}$  are the maximum and minimum Poisson's ratios of the investigated formation, respectively, dimensionless. The formula indicates that a

higher Young's modulus and a lower Poisson's ratio result in higher brittleness.

### 3.1.3 Pressure coefficient

One of the main characteristics of shale gas reservoirs discovered in marine strata in southern China is overpressure, where the pressure coefficient ( $C_p$ ) normally varies from 1.2 to 2.0. (Nie et al., 2015). Shale gas wells with high production generally have an abnormally high fluid pressure, and the gas content is positively correlated with the degree of overpressure (Guo and Zeng, 2015; Liu Luofu et al., 2018). The pressure coefficient indicates the preservation condition of shale gas and control the gas production (Wang Feiyu et al., 2013). According to the production data and formation pressure data of wells in Fuling shale gas field, the relationship between  $C_p$  and daily shale gas production can be obtained, as shown in Fig. 2. A positive correlation trend is obvious in this area, which is also consistent with the research results of previous studies. In addition, the higher the formation pressure, the higher the hydraulic horsepower needed. Thus, the  $C_p$  has an important impact on both the geology and operations.

### 3.2 Operating parameters

Due to the extremely poor reservoir properties of shale reservoirs, the volume fracturing technology is widely used. It aims to create the maximum contact area between the fracture and reservoir matrix and shorten the seepage distance of the gas from the matrix to the fracture in any direction by large-scale and high-rate fracturing treatments (Wu qi et al., 2012). Hence, the engineering factors cannot be neglected when studying fracability issues. The

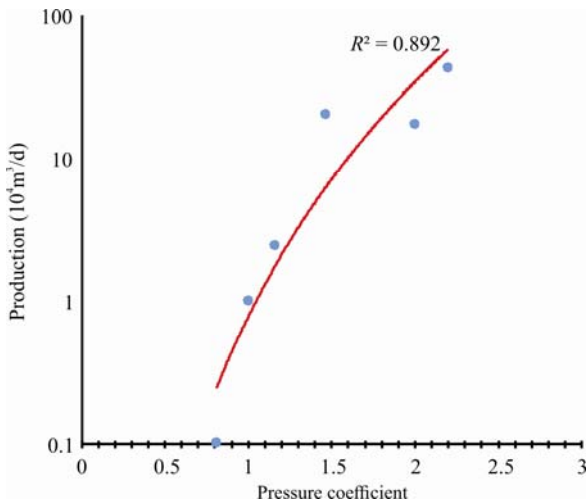


Fig. 2. The relationship between  $C_p$  and shale gas production.

operating parameters, including net pressure, fracturing scale and propping agents, can also influence fracability.

**3.2.1 Net pressure**

Considering the influence of the crack tip-induced stress, Kahraman used a linear elastic fracture mechanics solution and proposed an interface crossing criterion to determine whether the hydraulic fracture crosses a natural fracture (Kahraman et al., 2004):

$$\frac{-\sigma_H}{T_0 - \sigma_h} \geq \frac{0.35 + \frac{0.35}{\mu_f}}{1.06} \quad (5)$$

where  $\sigma_H$  and  $\sigma_h$  are the maximum and minimum principal stresses, respectively, MPa;  $T_0$  is the tensile strength of rocks, MPa; and  $\mu_f$  is the viscosity, mPa\*s. Studies show that the hydraulic fracture may extend as the net pressure increases. A natural fracture may open or the hydraulic fracture may cross the interface if the net pressure is high enough. Therefore, the energy that is carried with the fracturing fluids can be measured by the net pressure. The higher the net pressure, the more complex the created fracture network, and the higher the achieved production. In an actual frac treatment, the net pressure can be defined

as the total pressure inside the fracture minus the closure stress:

$$P_{net} = P_f - P_c \quad (6)$$

**3.2.2 Fracturing scale**

The fracturing scale is closely related to the created fracture length and the created fracture width in volume fracturing. Normally, a larger fracturing scale indicates a longer fracture length and higher stimulated reservoir volume. The microseismic monitoring of the Barnett Shale shows that the volume of fracturing fluids positively correlates with the size of the created fracture networks. The more fracturing fluids are pumped into the well, the more complex and longer fracture networks will be created (Cheng Yuanfang et al., 2014). For the shale gas demonstration zone in the Sichuan Basin, the volume of fracturing fluids pumped is approximately 1,400 to 1,800 m<sup>3</sup> and the volume of sand approximately 50 to 70 m<sup>3</sup> (Wang Zhigang et al., 2015). The discrete fracture network (DFN) model has been used to model hydraulic fracturing at different fracturing scales (Meyer et al., 2010). During the simulation process, the same type of fluids and proppants were used for cases #1 and #2. In addition, all fracturing treatment parameters were at the same value except for the volume of liquids and the mass of proppants (see Table 1). The simulation results are shown in Table 2.

Fig. 3 indicates that, at the same pumping rate, an increased volume of fracturing fluids and sand generated

**Table 1 Operating parameters for the simulation**

Simulation No.	Pumping rate m <sup>3</sup> /min	Perforation clusters	Cluster interval (m)	$C_p$	Fluid type
1	10	3	25	1.85	SW-1
2	10	3	25	1.85	SW-1

**Table 2 Simulation results of the treatment and fracture parameters**

Simulation No.	Frac fluids (m <sup>3</sup> )	Proppants* (m <sup>3</sup> )	Frac height (m)	Frac length* (m)	Propped length* (m)
1	1,500	60	40	206	143
2	2,000	80	40	282	205

Note: Proppants\* = Total volume of 30/50 mesh sand and 100 mesh ceramic powder. Frac length\* = Maximum distance between the wellbore and created fracture. Propped length\* = Maximum distance between the wellbore and propped created fracture.

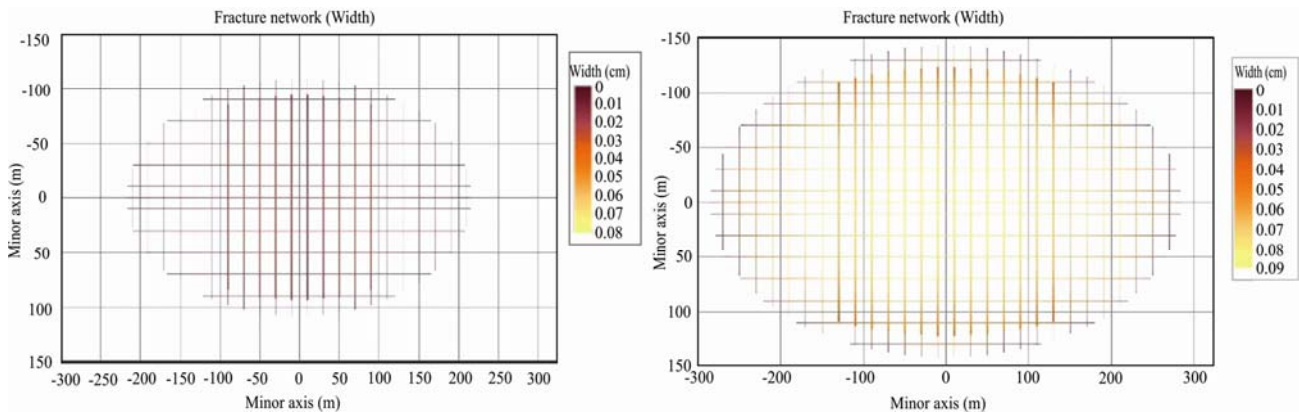


Fig. 3. DFN simulation results at different fracturing scales.

(a) DFN simulation results with 1500 m<sup>3</sup> of fracturing fluids and 60 m<sup>3</sup> of sands; (b) DFN simulation results with 2,000 m<sup>3</sup> of fracturing fluids and 80 m<sup>3</sup> of sands.

fractures of greater length, propped fractures of greater length and higher stimulated reservoir volumes. Hence, it is demonstrated that formations that can receive more fluids and sand are easier to fracture.

### 3.2.3 Fracturing fluids and proppants

Proppants are designed to prop open fractures during a fracturing treatment. They are added to fracturing fluids pumped into the well to create conductive fractures. Hence, the proppant volume pumped into the target zone represents the maximum room that the formation can accommodate. The ratio of the sand volume to the fluid volume suggests the ease of fracturing. A higher ratio indicates better fracability, and vice versa. Slickwater, which is a non-viscous fracturing fluid, is most widely used in shale gas reservoirs. It can generate complex fractures with low concentrations of proppants. For clay-rich and highly plastic shale reservoirs, linear gels and slickwater are combined as fracturing fluids because clay swelling can influence the permeability and porosity of shale. Since more viscous fluids can carry more concentrated proppants and fracturing fluids vary in their viscosity, the volume of linear gels is converted to adapt the slickwater volume system through the substitution method:

$$V_f' = V_{lg} \frac{(conc)_{lg}}{(conc)_{sw}} \quad (7)$$

where  $V_f'$  is the converted volume of linear gels,  $m^3$ ;  $V_{lg}$  is the volume of linear gels,  $m^3$ ;  $(conc)_{lg}$  is the average sand concentration added during linear gel fracturing,  $kg/m^3$ ; and  $(conc)_{sw}$  is the average sand concentration added during slickwater fracturing,  $kg/m^3$ . The total volume of fracturing fluids can be expressed as:

$$V_{total} = V_f' + V_{fsw} \quad (8)$$

$V_{fsw}$  is the actual volume of slickwater,  $m^3$ . The average viscosity  $\mu'$  can be expressed as:

$$\mu' = \mu_s \frac{V_{total}}{d_{fsw}} \quad (9)$$

Similarly, proppants vary in type and size, so their volume must be converted to the same unit before calculation. In this paper, the influence of the proppant type is ignored and only the proppant size is taken into consideration for convenience. Proppants with a size of 100 mesh and 30/50 mesh should be converted to 40/70 mesh proppants with the use of a conversion factor, which is the ratio between the average diameters of the two proppants. Thus, the volume of 100 mesh proppants should decrease while that of 30/50 mesh should increase. The converted volume can be expressed as:

$$v_s' = v_{s100} \frac{d_{100}}{d_{40/70}} \quad (10)$$

where  $v_s'$  is the converted volume of proppants,  $m^3$ ;  $v_{s100}$  is the volume of 100 mesh proppant,  $m^3$ ;  $d_{100}$  is the average diameter of 100 mesh proppant, mm; and  $d_{40/70}$  is the average diameter of 40/70 mesh proppant, mm.

### 3.2.4 Fracability evaluation model of shale reservoir

High shale gas production is based on favorable geological and operating conditions. Better reservoir conditions indicate a higher gas production potential. In general, the geological parameters are mostly constant, so the relationship between them and the gas production can be simplified as a linear relationship. However, the operating parameters are variable, so the relationship between them and the gas production dynamically changes depending on the process. Considering the two different relationships, a unified fracability evaluation model is proposed as follows:

$$GRFI = \frac{c \times C_p \times BI \times RQI \times \left( \frac{P_f - P_c}{\mu'} \right)^a \times Q^b \times t^c \times (conc)^d}{L} \quad (11)$$

where  $GRFI$  is the general reservoir fracability index, representing both the geological and operating parameters;  $C$  is the unit conversion coefficient;  $Q$  is the pumping rate;  $t$  is the fracturing time;  $conc$  is the average sand concentration; and  $L$  is the length of the horizontal well. Since the  $GRFI$  is defined as dimensionless, the coefficients including  $a$ ,  $b$ ,  $c$  and  $d$  can be defined with the application of dimensional analysis. The  $GRFI$  can be

$$GRFI = \frac{\left( \frac{m^3}{kg} \right) \times \left( \frac{MPa}{mPa \cdot s} \right)^a \times \left( \frac{m^3}{min} \right)^b \times (min)^c \times \left( \frac{kg}{m^3 / min} \right)^d}{(m)} \quad (12)$$

expressed as follows:

$$GRFI = \frac{c \times C_p \times BI \times RQI \times \left( \frac{P_f - P_c}{\mu'} \right)^a \times Q^{b/3} \times t^{c/3} \times (conc)}{L} \quad (13)$$

The equation can be simplified to:

## 4 Results and Discussions

The new fracability evaluation model has been applied to the Huangjinba shale gas block in Zhaotong demonstration zone in Sichuan, China. The shale gas in the Upper Ordovician Wufeng Formation–Lower Silurian Longmaxi Formation in the Sichuan Basin, China, has been discussed. Based on the geological parameters and operating parameters, two representative platforms including 5 wells in the Huangjinba shale gas block were chosen, and the correlation between the  $GRFI$  and the effectiveness of the hydraulic fracturing was analyzed. Fig. 4 and Fig. 5 show the TOC distribution and total gas (TGAS) distribution of the first bed and the third bed of member I of the Longmaxi formation.

The correlation coefficient can be obtained with the use of GRA:

$$\xi(x_i) = \frac{\Delta(min) + \rho \Delta(max)}{\Delta(x_i) + \rho \Delta(max)} \quad (14)$$

$$\gamma_i = \frac{1}{N} \sum_{k=1}^N \xi_i(k) \quad (15)$$

where  $\xi(x_i)$  is the gray relational coefficient,  $\Delta(min)$  is the second-order minimum difference,  $\Delta(max)$  is the second-



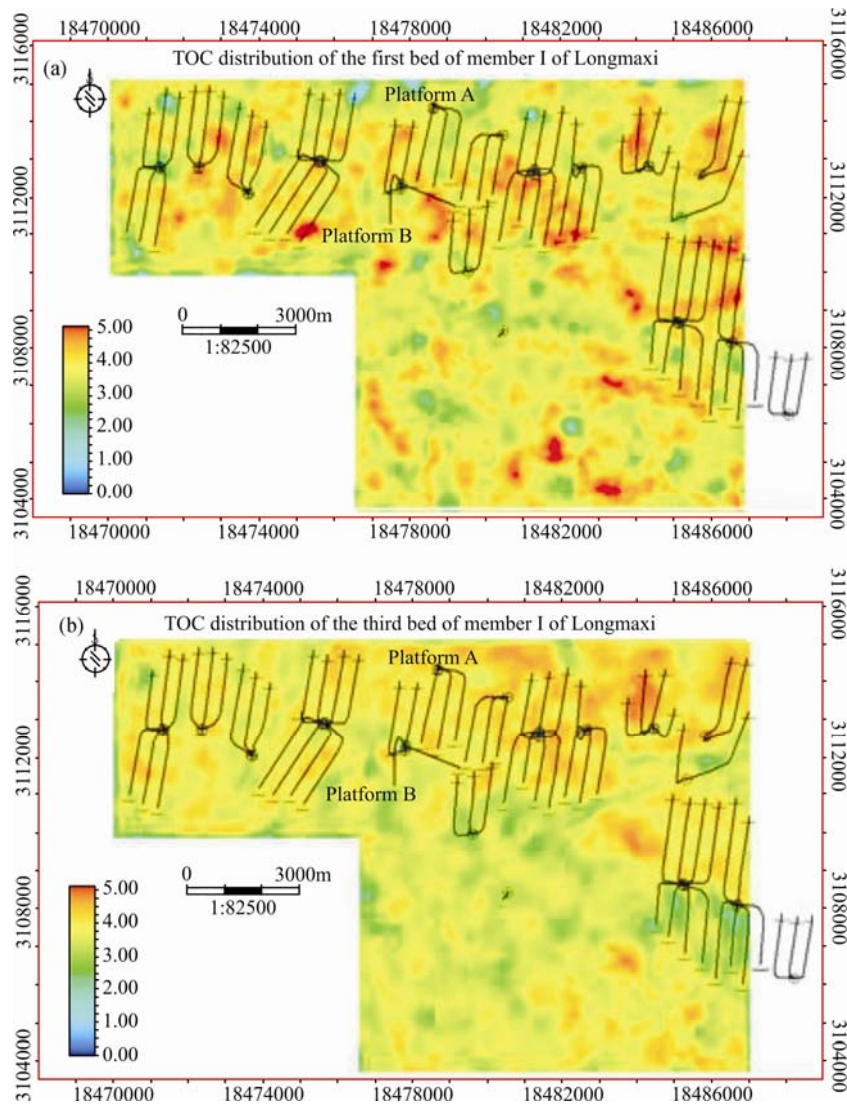


Fig. 4. Geologic model of the Huangjinba Block—TOC.  
(a) TOC distribution of the first bed of member I of the Longmaxi Formation; (b) TOC distribution of the third bed of member I of the Longmaxi Formation.

order maximum difference,  $\Delta(x_i)$  is the absolute difference between the standard data array (production data) and the correlation data array (geological parameters),  $\gamma_i$  is the correlation coefficient, and  $N$  is the number of samples. Fig. 6 shows the correlation between each parameter and the gas production of the 5 wells. The normalized weight coefficients of each parameter are 0.39, 0.21 or 0.40.

With the physical meaning of the equation considered, Eq. 1 can be rewritten as follows:

$$RQI = (TOC) \times (\varphi_e)^{0.5} \times (TGAS) \quad (16)$$

For the shales of the Lower Silurian Longmaxi Formation in the Sichuan Basin, China, the Young's modulus ranges from 8 to 56 GPa, with an average value of 32 GPa, and the Poisson's ratio ranges from 0.10 to 0.36, with an average value of 0.18 (Wang Zhigang et al., 2015). Thus, the BI of the Longmaxi shale can be expressed as follows:

$$E_{BRIT} = (E_c - 8) / 48 \quad (17)$$

$$v_{BRIT} = (0.36 - v_c) / 0.26 \quad (18)$$

$$BI = \frac{E_{BRIT} + v_{BRIT}}{2} \quad (19)$$

According to Eq. 19 and the logging data of platforms A and B, the geological parameters are summarized in Table 3. The data suggest that the RQ of platform A was better than that of platform B.

As Fig. 7 shows, the RQI had a positive correlation with the shale gas production, which means that high gas production was based on a high RQ value. Moreover, if the RQI is highly variable in the same platform, this suggests that the reservoirs of the area are highly heterogeneous.

Table 4 shows the operating parameters of platforms A and B. The data indicate that the fracturing scale of platform A was larger and that the pumping rate of platform A was higher as well, which implies that the energy carried by the fracturing fluids of platform A was

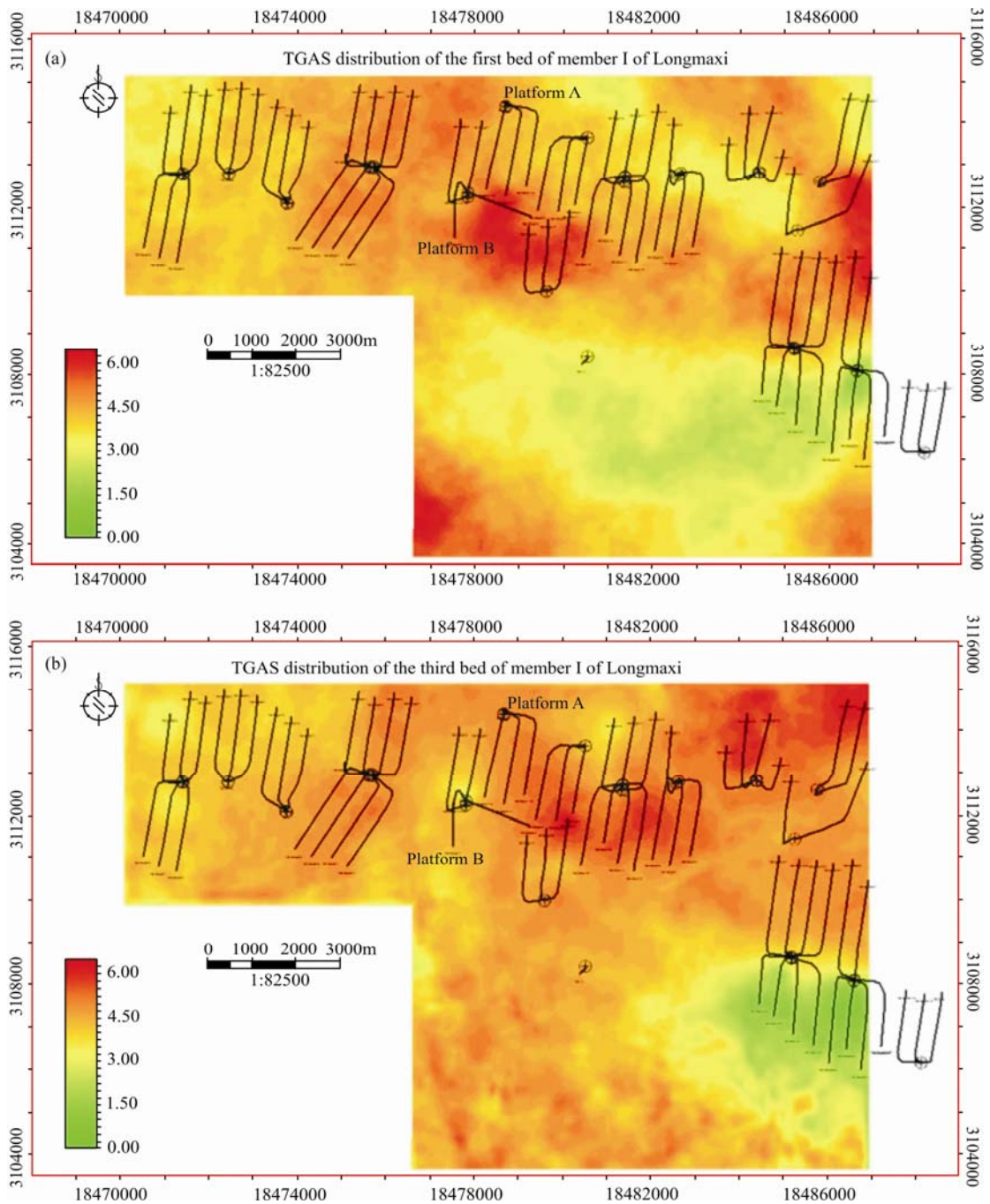


Fig. 5. Geologic model of Huangjinba Block—TGAS. (a) TGAS distribution of the first bed of member I of the Longmaxi Formation; (b) TGAS distribution of the third bed of member I of the Longmaxi Formation.

greater. Thus, the net pressure at platform A during fracturing was higher, making it easier for the fracturing fluids used in platform A to form complex fracture networks.

The net pressure and converted volume of the fracturing fluids of each well can be calculated by Eq. 6, Eq. 8 and Eq. 10. Fig. 8(a) shows the negative correlation between the net pressure and shale gas production, which is in contrast to the analysis conclusions in 3.2.1. The reason for this result is that platform B was located near a fault

Table 3 Geological parameters of platform A and B

Well	TOC (%)	PIGE (%)	TGAS (m³/ton)	BI	ξ	RQI (m³/ton)	Prod (10⁴ m³/d)
A-1	4.12	3.82	4.93			39.70	9.0
A-2	3.74	3.95	4.97	0.63	2.00	36.94	9.4
A-3	3.96	4.24	5.38			43.87	10.9
B-1	3.56	3.71	4.51			30.93	3.5
B-2	2.93	3.15	3.88	0.59	1.93	20.18	3.6

zone and platform B operated at a higher pressure. Fig. 8 (b) shows the linear correlation between the fracturing scale and shale gas production. A larger fracturing scale indicates higher gas production.

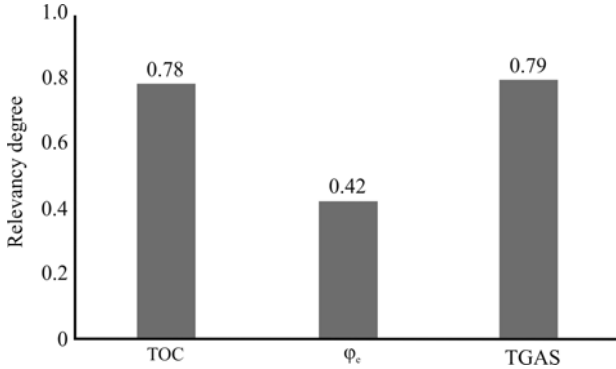


Fig. 6. The relevancy degree between each geological parameter and shale gas production.

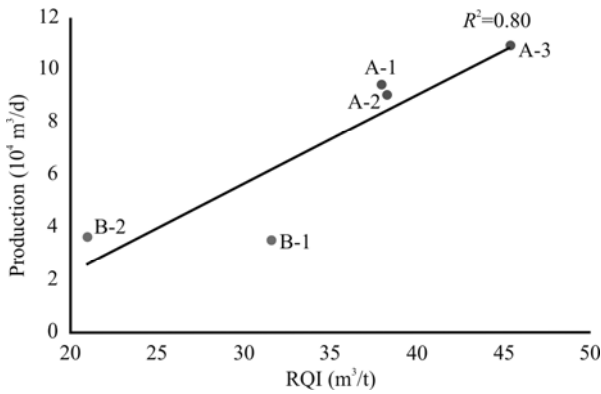
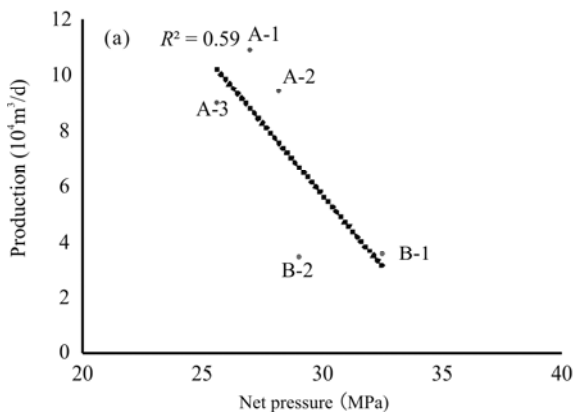


Fig. 7. The correlation between the RQI and shale gas production.

**Table 4 Treatment parameters of platform A and platform B**

Well Stages	Horizontal Length (m)	Slurry rate (m <sup>3</sup> /min)	P <sub>f</sub> (Mpa)	P <sub>c</sub> (Mpa)	Total fluids (m <sup>3</sup> )	Total sands (m <sup>3</sup> )	
A-1	16	11.74	11.8	73.7	48.1	30593	1417.5
A-2	20	1491	11.7	76.2	48.0	37770	1576.0
A-3	19	1395	11.4	75.6	48.6	33822	1378.7
B-1	22	1500	8.9	89.2	60.2	40101	1091.9
B-2	17	1228	9.9	83.9	51.4	27687	517.4



The GRFI of platforms A and B can be calculated by Eq. 13. Fig. 9 shows the linear correlation between the GRFI and shale gas production. A higher GRFI indicates a better fracability and higher gas production. According to Fig. 9, the fitting equation can be written as:

$$Prod = k \times GRFI + b \quad (20)$$

where *Prod* is the daily production of the shale gas well, 10<sup>4</sup> m<sup>3</sup>/d; *k* is the constant coefficient determined by the target zone, *k* was set as 0.0015 in this case; and *b* is the well production without stimulation measures; however, the minimum production in the target zone was used because there is normally no production for a shale gas well without stimulation measures. Parameter *b* was set as 2 in this case. Thus, Eq. 20 can be expressed as follows:

$$Prod = 0.0015 \times GRFI + 2 \quad (21)$$

The threshold value of the GRFI depends on the break-even point of each well. Based on the exploration experience in the Huangjinba block, values of 5×10<sup>4</sup> and 10×10<sup>4</sup> m<sup>3</sup>/d are considered the limits of the low production well and the high yield well, respectively. Hence, the lower limit of the GRFI is 2,000, while a value of 5,300 or above is the optimum GRFI value in the Huangjinba block.

**5 Conclusions**

The fracability of shale reservoirs plays a vital role in

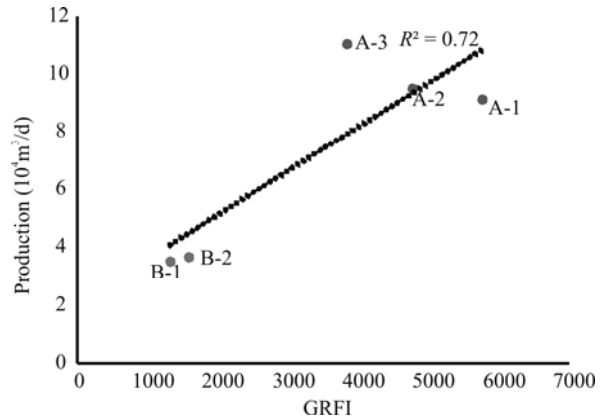


Fig. 9. The correlation between the GRFI and shale gas production.

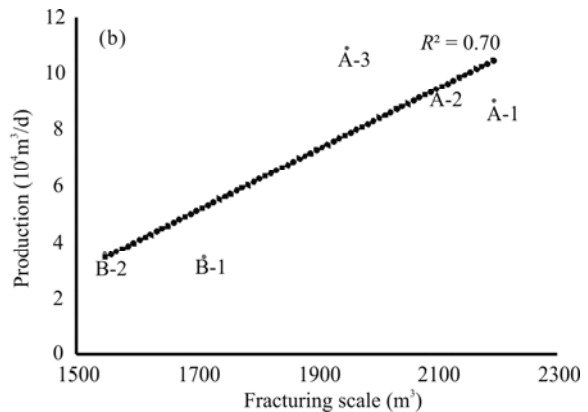


Fig. 8. The correlation between the treatment parameters and shale gas production.

(a) The correlation between net pressure and shale gas production; (b) The correlation between the fracturing scale and shale gas production.



drilling and hydraulic fracturing. This paper develops an integrated geologic and operational approach for characterizing the fracability of shale reservoirs. The RQI is introduced to indicate the geological potential. The BI and  $C_p$ , as the key parameters influencing the fracability, are discussed as well. For different types and volumes of fracturing fluids and propping agents, normalization is implemented for calculation purposes. With both the geological and operating parameters considered, a new fracability evaluation model is established. The following conclusions are obtained:

(1) High shale gas production is based on high reservoir quality. For the research area, the RQI of each well varies greatly in the same platform, which suggests that the reservoirs of the Huangjinba block are highly heterogeneous.

(2) Since the fracturing fluids and propping agents differ in volumes and types, the volumes must be converted to the same system of units to characterize the fracturing scale. The fracturing scale is positively correlated with shale gas production.

(3) The new fracability evaluation model is applied to platform wells, and the results show that the effectiveness of hydraulic fracturing correlates strongly with the GRFI. When the GRFI has a value of 5,300 or above, the area or platform can be selected as a priority development region. When the GRFI is lower than 2,000, it is not suggested to implement an exploitation program in this area. However, the GRFI may change due to changes in the oil price and advances in technology.

In summary, the GRFI model proposed in this paper has a better resolution than the existing models. The accuracy and feasibility of this approach are proved by a field case study. The GRFI model provides a practical method to screen formations with great potential to create a maximum reservoir stimulation volume and optimize well trajectories and perforation positions. However, one should be cautious when calculating the weight coefficients of the RQI through GRA. Sampling errors may occur since the weight coefficients vary according to the number and quality of the samples. With shale gas exploitation deepening, more data will be collected, and the new fracability evaluation model will become more accurate.

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