A comprehensive approach for fracability evaluation in naturally fractured sandstone reservoirs based on analytical hierarchy process method

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Abstract
The tight sandstone gas reservoir in southern Songliao Basin is naturally fractured and is characterized by its low porosity and permeability. Large-scale hydraulic fracturing is the most effective way to develop this tight gas reservoir. Quantitative evaluation of fracability is essential for optimizing a fracturing reservoir. In this study, nine fracability-related factors, particularly mechanical brittleness, unconfined compressive strength (UCS), mineral brittleness, cohesion, internal friction angle (IFA), natural fracture, fracture toughness, horizontal stress difference, and fracture barrier were obtained based on a series of petrophysical and geomechanical experiments. Taking above factors into consideration, a modified comprehensive evaluation model is proposed based on analytic hierarchy process (AHP) method. The UCS and IFA were removed from the AHP model based on the results of factor correlation analysis. The transfer matrix in the weighting procedure was applied to improve the consistency of judgment matrix, and the fuzzy matrix was employed to promote the objectiveness of final decision. The fracability evaluation of four reservoir intervals in Jinshan gas field was analyzed. Field fracturing tests were conducted to verify the feasibility of the proposed evaluation model. Results showed that the tubing pressure curve is more fluctuated in the reservoir interval with more developed natural fractures, and gas production is higher in the reservoir interval with greater fracability coefficient. The field test data coincide with the results of the proposed evaluation model.

KEYWORDS
analytical hierarchy process, fracability evaluation, geomechanical experiment, naturally fractured sandstone
1 | INTRODUCTION

Hydraulic fracturing is one of the most important measures for developing low-porosity and low-permeability reservoirs.\(^1\) It is essential for developing tight sandstone gas reservoirs, where the porosity is generally lower than 10% and the permeability is lower than 0.1 mD. Tight sandstone bearing abundant natural gas is widely distributed in China and has attracted more attention in recent years. Volumetric fracturing has been an important technique used in shale gas fracturing and is used to develop other unconventional resources, such as natural tight sandstone gas. After injecting a large amount of fracturing fluid with high pumping rate, natural fractures can be easily connected by hydraulic fracture, and complex fracture networks are generated.\(^4\) Stimulated reservoir volume (SRV) had been a very important parameter to quantitatively express the fracturing results. Many statistical results have suggested that more gas can be usually obtained if a larger SRV is created.\(^5\)

Fracability is a key parameter that has been used to evaluate whether the reservoir can be easily fractured and produce a large SRV.\(^6\) Higher fracability indicates that larger SRV will be obtained. In recent years, there have been many reports on fracability evaluation. Originally, rock brittleness was adopted to evaluate fracability. Various brittleness evaluation equations were established, and the most popular among them was proposed by Rickman et al.\(^7\) According to his viewpoint, brittleness combines the Young's modulus and Poisson's ratio and can represent the level of fracability. Mineral composition also affects the fracability. The fracability level increases with increased content of brittle minerals. The content of quartz was first used to represent shale brittleness,\(^8\) and then dolomite was regarded as another brittle mineral.\(^9\) It was then observed that some silicate minerals such as feldspar and mica are more brittle than clays. However, it has been proved that some reservoirs with high brittleness are not fractured easily. This means that brittleness alone is not enough to describe fracability.\(^10\) Fracture toughness is also an important factor affecting the level of fracability because a higher fracture toughness indicates the rock can better resist fracture initiation and propagation. Furthermore, Guo et al.\(^11\) established a fracability evaluation model for tight sandstone that includes brittleness, fracture toughness, and internal friction angle. Tang et al.\(^12\) regarded four parameters including brittleness, natural fractures, quartz content, and diagenesis as the primary factors influencing fracability. Mullen and Enderlin\(^13\) integrated the reservoir properties, mineral distribution, and the plane weakness to quantify fracability. Fang and Amro\(^14\) discussed the influencing factors of shale fracability, such as the sedimentary environment, mineral composition, brittleness, and natural fractures. Geng et al.\(^15\) proposed an integrated fracability assessment methodology to correlate conventional post-stack seismic data with well production rate. Kivi et al.\(^16\) established an intelligent approach to evaluate brittleness from conventional well logs and adaptive neuro-fuzzy inference system (ANFIS) was employed to develop a robust correlation of brittleness index with well logs. Wu et al.\(^17\) used combination weight method which considers four main fracability-related factors, brittleness, quartz content, diagenesis, and natural fracture to evaluate shale fracability. Yuan et al.\(^18\) derived an improved model which combines fracture toughness, brittleness, and minimum horizontal principal stress on the basis of well logging data. Sui et al.\(^19\) creatively used analytic hierarchy process (AHP) method to establish a quantification model for fracability evaluation of shale gas reservoirs. In the model, many important fracability-related factors, such as brittleness, brittle mineral content, clay mineral content, cohesion, internal friction angle (IFA), and unconfined compressive strength (UCS) were included. The fractal geometry was firstly used to characterize the fracture degree of the shale cores which were conducted hydraulic fracturing experiments.

Summarizing the previous researches on fracability evaluation, the former evaluation models mainly include mineral composition and rock mechanical properties. However, some important factors such as natural fracture was not included, which may lead to bias for fracability evaluation of naturally fractured reservoirs. AHP is a promising mathematical method that can include more important influencing factors and evaluate the fracability comprehensively. In this paper, inspired by the study in the reference,\(^19\) the AHP was used to establish a comprehensive fracability evaluation model for naturally fractured sandstone reservoir. The mathematical fundamentals of the AHP and how to frame a scalable comprehensive fracability evaluation model had been clearly introduced in the reference.\(^19\) However, compared to Sui's model,\(^19\) natural fracture was included in our model, and the developed levels of natural fractures were analyzed quantitatively. Moreover, factor correlation was studied in our work to remove the minor factors who have remarkable mutual effects with other factors. In the proposed AHP model, a fuzzy matrix and a transfer matrix were introduced in order to evaluate the reservoir fracability more objectively. In the model, the maximum and minimum of influencing factors in the field were taken into account in the process of standardization in order to make the normalized factors more practically and meaningful. In our work, nine significant influencing factors, including mechanical brittleness, unconfined compressive strength (UCS), mineral brittleness, cohesion, internal friction angle (IFA), natural fracture, fracture toughness, horizontal stress difference, and fracture barrier have been taken into account primarily, and they are obtained from corresponding experiments. This model is expected to provide some guidance for well selection and layer selection for hydraulic fracturing operation of naturally fractured sandstone reservoirs. Afterwards, this model is verified by application
of fracturing tests in the Yingcheng formation, Jinshan gas field, China. Four reservoir intervals were selected by geologists in order to evaluate their fracability, denoted as Sand#1 (well X1, 2325 m), Sand#2 (well X2, 2412 m), Sand#3 (well X3, 2416 m), and Sand#4 (well X4, 2367 m).

2 | FACTORS INFLUENCING ROCK FRACABILITY AND CORRESPONDING EXPERIMENTS

To obtain the values of the factors included in the fracability evaluation model, several experimental tests were performed, including compression test, X-ray diffractometer measurement, SNBD test, X-ray CT scan, and acoustic emission test. These tests were conducted on cores drilled from the four reservoir intervals.

2.1 | Mechanical parameters through compression test

2.1.1 | Triaxial compression test results

A triaxial compression experiment is an important method for measuring rock mechanical parameters.20 In the experiment, a standard core (25.2 mm in diameter) drilled from the original core (105 mm in diameter) is placed in a chamber under a confining pressure. Then increasing axial pressure is applied to the core until the core breaks. A stress-strain curve can be drawn based on the recorded experimental data, and the peak value of the curve is the compressive strength. In addition, the Young’s modulus (YM) and Poisson’s ratio (PR) can be calculated from the curve. We obtained 12 rock samples from the four reservoir intervals. The specimens were tested by an RTR-1000 triaxial rock mechanics system (Figure 1) at the reservoir temperature of 70°C under different confining pressures (Table 1), and the maximum from each group is the predicted reservoir confining pressure. The test results show that the compressive strength ranges from 22.5 to 200.8 MPa, the Young’s modulus ranges from 2589.5 to 20 968.4 MPa, and Poisson’s ratio ranges from 0.119 to 0.390.

2.1.2 | Mechanical brittleness

Mechanical brittleness is a key factor for characterizing reservoir fracability.21 A higher mechanical brittleness means that the sandstone fractures more easily, which is beneficial for obtaining a larger SRV. Among many proposed formulas, we noticed that the Young’s modulus and Poisson’s ratio are simpler and more applicable for defining rock brittleness. The Young’s modulus of a rock represents its ability to maintain an opened fracture, and Poisson’s ratio represents its ability to break under hydraulic pressure. The most widely used formula has been put forward by Rickman et al.7 In Rickman’s model, the brittleness index is defined as:

\[ \text{YM}_{\text{BRIT}} = \frac{\text{YM} - \text{YM}_{\min}}{\text{YM}_{\max} - \text{YM}_{\min}} \]  
\[ \text{PR}_{\text{BRIT}} = \frac{\text{PR}_{\max} - \text{PR}}{\text{PR}_{\max} - \text{PR}_{\min}} \]  
\[ B_{\text{RIT}} = \frac{\text{YM}_{\text{BRIT}} + \text{PR}_{\text{BRIT}}}{2} \]

where \( B_{\text{RIT}} \) is the rock brittleness index, \( \text{YM}_{\text{BRIT}} \) is the normalized Young’s modulus, \( \text{PR}_{\text{BRIT}} \) is the normalized Poisson’s ratio, \( \text{YM}_{\max} \) [MPa] is the maximum Young’s modulus, \( \text{YM}_{\min} \) [MPa] is the minimum Young’s modulus, \( \text{PR}_{\max} \) is the maximum Poisson’s ratio, and \( \text{PR}_{\min} \) is the minimum Poisson’s ratio.

We extracted the third group of experimental data from each reservoir interval. Rickman’s model was used to calculate the brittleness index, and the results are listed in
Table 2. According to the data in Jinshan gas field, $YM_{\text{min}}$ and $YM_{\text{max}}$ are 10,000 and 60,000, respectively; $PR_{\text{min}}$ and $PR_{\text{max}}$ are 0.12 and 0.4, respectively.

### Cohesion and internal friction angle

Cohesion refers to the attractive force between different components inside the rock. The Mohr-Coulomb’s criterion indicates that the rock begins to break only when the maximum shear stress exceeds its critical value. A higher cohesion means the rock is more difficult to fracture. Obviously, cohesion is a typical negative index of fracability.

The internal friction angle (IFA) refers to the inclination angle of the failure plane of a standard core under axial pressure and reflects a rock’s resistance to slide along the failure plane. If the shear strength of an interface is high enough, slippage will not occur during fracturing. The shear strength is closely related to the IFA. The smaller the IFA is, the easier the rock slides along the plane, which is beneficial to the generation of a fracture network and enhances SRV. That is to say, the IFA is also a negative index of fracability.

A Mohr circle of limited shear stress ($\tau$) along normal stress ($\sigma$) can be drawn under a confining pressure. Thus, we can draw more than one Mohr circle after few compression tests have been conducted under different confining pressures. Then a linear outer tangent envelope curve that indicates the critical rock failure state can be constructed. The angle between the straight line and the x-axis is defined as the IFA, and the intercept of the line on y-axis is defined as cohesion. The relation between $\tau$ and $\sigma$ can be described by Equation (4). The IFA and cohesion can be obtained, as shown in Table 3.

\[
\tau = \sigma \tan \phi + C,
\]

where $\tau$ [MPa] is the shear stress, $\sigma$ [MPa] is the normal stress, $\phi$ [°] is the internal friction angle, and $C$ [MPa] is the cohesion.

### Unconfined compressive strength (UCS)

Huacka and Das proposed that rock brittleness can be represented by the ratio of UCS to tensile strength. The higher this ratio is, the easier the rock is fractured. In fact, tight sandstone has a very low tensile strength, so the UCS is an influencing factor of rock fracability. The value of UCS (confining pressure is 0) can be extracted from Table 1. The rocks fracture easier under higher UCS. Consequently, the UCS can be taken as a positive index of fracability.

### Table 1

**Compression test results under different confining pressures**

| Categories | Well name | Depth (m) | Confining pressure (MPa) | Compressive strength (MPa) | YM (MPa) | PR |
|------------|-----------|-----------|--------------------------|----------------------------|----------|----|
| Sand#1     | X1        | 2325      | 0                        | 22.5                       | 2589.5   | 0.204 |
|            |           |           | 15                       | 120.3                      | 14 586.6 | 0.162 |
|            |           |           | 26.7                     | 152.6                      | 17 578.0 | 0.390 |
| Sand#2     | X2        | 2412      | 0.0                      | 45.6                       | 4833.9   | 0.123 |
|            |           |           | 16.0                     | 148.1                      | 14 088.0 | 0.139 |
|            |           |           | 27.7                     | 200.8                      | 19 228.1 | 0.130 |
| Sand#3     | X3        | 2416      | 0.0                      | 50.9                       | 7451.2   | 0.131 |
|            |           |           | 15.0                     | 143.1                      | 18 612.2 | 0.129 |
|            |           |           | 27.8                     | 191.8                      | 20 968.4 | 0.267 |
| Sand#4     | X4        | 2367      | 0.0                      | 54.3                       | 5347.9   | 0.119 |
|            |           |           | 15.0                     | 136.1                      | 14 135.9 | 0.149 |
|            |           |           | 27.2                     | 164.4                      | 17 459.4 | 0.188 |

### Table 2

**Young’s modulus, Poisson’s ratio, and mechanical brittleness**

| Categories | Well name | Depth (m) | YM (MPa) | PR | $B_{\text{RIT}}$ |
|------------|-----------|-----------|----------|----|-----------------|
| Sand#1     | X1        | 2325      | 17 578.0 | 0.390 | 0.094         |
| Sand#2     | X2        | 2412      | 19 228.1 | 0.130 | 0.574         |
| Sand#3     | X3        | 2416      | 20 968.4 | 0.267 | 0.347         |
| Sand#4     | X4        | 2367      | 17 459.4 | 0.188 | 0.453         |
Mineral brittleness

In addition to the Young’s modulus and Poisson’s ratio, the mineral content also plays an important role in influencing rock fracability. The higher the brittleness mineral content is, the more brittle the rock is. Accordingly, complex fracture networks will be more easily generated during fracturing. For tight sandstone, quartz is regarded as the only brittle mineral. An equation proposed by Sondergeld et al.\textsuperscript{23} is used to calculate the mineral brittleness (Equation 5). An X-ray diffractometer (X’Pert PRO MPD, PANalytical B.V. Corporation, Netherland) was used to test the mineral content of the obtained samples in the laboratory. The test results are shown in Table 4.

\[
BI = \frac{W_Q}{W_Q + W_{Carb} + W_C},
\]

where BI is the mineral brittleness index, \(W_Q\) [%] is the quartz content, \(W_{Carb}\) [%] is the carbonate mineral content, and \(W_C\) [%] is the clay mineral content.

Fracture toughness

Another important factor for evaluating the rock fracability is fracture toughness. It represents the ability of rock to resist fracture initiation and propagation during fracturing. Generally, fracture toughness can be categorized into three types: the opening type (Model-I), the staggered type (Model-II), and the tearing type (Model-III).\textsuperscript{24} When Model-I toughness is lower, the hydraulic fractures will be more easily opened and longer fractures will be generated, which means a larger SRV can be obtained. When Model-II toughness is lower, more shear slip actions will occur in hydraulic fractures and natural fractures, which means higher fracture conductivity and more effective SRV can be obtained. Generally, Model-I and Model-II toughness are dominant in fracturing, and they will be discussed in this paper.

There are many prediction models of Model-I and Model-II toughness for conventional sandstones. However, there are few reliable models for determining the fracture toughness of naturally fractured sandstones. Awaji and Sato\textsuperscript{25} first proposed an analysis of a disk test in which a circular specimen with an internal crack is subjected to the diametral loading as shown in Figure 2. This method of test is called straight-notched Brazilian disk (SNBD), which was adopted in this study to determine Model-I and Model-II toughness of the obtained samples.\textsuperscript{26,27} The tests were carried out at the reservoir temperature of 70°C. The experimental steps are described as follows:

**Table 3** Compression test results under different confining pressures

| Categories | Well name | Depth (m) | Confining pressure (MPa) | Compressive strength (MPa) | \(\varphi\) (°) | C (MPa) |
|------------|-----------|-----------|--------------------------|---------------------------|--------------|---------|
| Sand#1     | X1        | 2325      | 0                        | 22.5                      | 44.09        | 9.7     |
|            |           |           | 15                       | 120.3                     |              |         |
|            |           |           | 26.7                     | 152.6                     |              |         |
| Sand#2     | X2        | 2412      | 0.0                      | 45.6                      | 47.09        | 11.15   |
|            |           |           | 16.0                     | 148.1                     |              |         |
|            |           |           | 27.7                     | 200.8                     |              |         |
| Sand#3     | X3        | 2416      | 0.0                      | 50.9                      | 47.43        | 11.07   |
|            |           |           | 15.0                     | 143.1                     |              |         |
|            |           |           | 27.8                     | 191.8                     |              |         |
| Sand#4     | X4        | 2367      | 0.0                      | 54.3                      | 41.03        | 16.86   |
|            |           |           | 15.0                     | 136.1                     |              |         |
|            |           |           | 27.2                     | 164.4                     |              |         |

**Table 4** Mineral content and mineral brittleness

| Categories | Well name | Depth (m) | \(W_Q\) (%) | \(W_{Carb}\) (%) | \(W_C\) (%) | BI  |
|------------|-----------|-----------|--------------|------------------|-------------|-----|
| Sand#1     | X1        | 2325      | 50.5         | 15.2             | 2.0         | 0.746 |
| Sand#2     | X2        | 2412      | 42.9         | 1.2              | 23.3        | 0.636 |
| Sand#3     | X3        | 2416      | 47.4         | 1.2              | 6.5         | 0.860 |
| Sand#4     | X4        | 2367      | 37.3         | 0.9              | 5.6         | 0.852 |
1. Sample processing: The original core drilled from the reservoir has a diameter of 105 mm. A smaller core with a diameter of 50 mm was extracted by drilling vertically into the original core. Then the core was cut into a disk with thickness of 20 mm, and the disk was polished horizontally.

2. Setting an initial crack: A water jet saw was used to create an initial crack in the center of the disk sample. The length of the crack was nearly 17 mm, and its width was 3 mm.

3. Disk test: The processed disk sample was placed between two bearing plates and the load direction was adjusted. For determining Model-I toughness, applied load and initial fracture were set along a line. For determining Model-II toughness, the angle between the applied load direction and initial fracture were set to 30° (Figure 3). The load pressure was increased at a rate of 0.2 MPa/s until the initial crack began to propagate, and the failure load pressure was recorded.

On the basis of SNBD test, Atkinson obtained the following equations for the determination of Model-I and Model-II toughness:

\[ K_{IC} = \frac{P\sqrt{a}}{RB\sqrt{\pi}} N_I \]  
\[ K_{IIc} = \frac{P\sqrt{a}}{RB\sqrt{\pi}} N_{II} \]

\[ N_I = 1 - 4\sin^2\theta + 4\sin^2\theta (1 - 4\cos^2\theta) \left( \frac{a}{R} \right)^2 \]  
\[ N_{II} = \left[ 2 + (8\cos^2\theta - 5) \left( \frac{a}{R} \right)^2 \right] \sin(2\theta), \]

where \( K_{IC} \) [MPa·m\(^{1/2}\)] is the Model-I fracture toughness, \( K_{IIc} \) [MPa·m\(^{1/2}\)] is the Model-II fracture toughness, \( P \) [KN] is the failure load pressure, \( a \) [mm] is the half length of the initial fracture, \( R \) [mm] is the radius of the disk sample, \( B \) [mm] is the thickness of the disk sample, \( N_I \) is the Model-I dimensionless stress intensity factor, \( N_{II} \) is the Model-II dimensionless stress intensity factor, and \( \theta \) [°] is the angle between the applied load direction and the initial fracture.

The test results of Model-I and Model-II toughness are shown in Table 5.

### 2.4 Natural fractures

A natural fracture is a structural surface with weak mechanical properties. When a hydraulic fracture encounters a natural

![Figure 2: Schematic of straight-notched Brazilian disk test](image)

![Figure 3: The sample images after straight-notched Brazilian disk test: (A) Model-I toughness test, and (B) Model-II toughness test](image)
In situ stress

2.5.1 Experimental method and results

Acoustic emission (AE) refers to the characteristic and irreversible sound emitted by a material when the material is deformed. The acoustic emission technique is one important method for monitoring in situ stress. The experimental steps are shown as follows:

1. Acoustic velocity detection: A digital oscilloscope (DS-1ten2E, RIGOL Technologies Corporation, China) was used to measure the P-wave velocity along the radial direction of the original core drilled from different angles. The direction of maximum horizontal principal stress has minimum acoustic velocity (Figure 5), and the direction of minimum horizontal principal stress has maximum acoustic velocity.

2. Stress measurement: Standard cores with 25.2 mm diameter were drilled from the original core along the maximum horizontal principal stress direction and the minimum horizontal principal stress direction. The rock acoustic emission and triaxial compression test are conducted synchronously. From the AE hit number-axial loading pressure curve, the point corresponding to the greatest slope of the curve is the Kaiser effect point, and its abscissa value is the Kaiser point stress. The in situ stress can be calculated using the equations below, and the results are shown in Table 7.

\[
\begin{align*}
\sigma_H &= K_H + aP_b \\
\sigma_h &= K_h + aP_b \\
\alpha &= 0.1837 \ln \phi + 0.1874 \\
P_b &= \beta \times H / 100,
\end{align*}
\]

where \(\sigma_H [\text{MPa}]\) is the maximum horizontal principal stress, \(\sigma_h [\text{MPa}]\) is the minimum horizontal principal stress, \(K_H [\text{MPa}]\) is the maximum Kaiser point stress, \(K_h [\text{MPa}]\) is the minimum Kaiser point stress, \(\alpha\) is the Boit coefficient, \(P_b [\text{MPa}]\) is the pore pressure, \(\phi\) is the Boit porosity, \(\beta [\text{MPa/m}]\) is the reservoir pressure gradient, and \(H [\text{m}]\) is the reservoir depth.

Among them, Equation (12) is the empirical formula that is used to calculate the Boit coefficient of tight sandstone.

2.5.2 Horizontal stress difference

In situ stress is a key factor to influence fracture networks generation. Blanton conducted several true triaxial fracturing tests on large outcrop cores. The results show that a lower horizontal principal stress difference results in easier

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**Table 5** Straight-notched Brazilian disk test results and fracture toughness values

| Categories | Well name | Depth (m) | Fracture type | R (mm) | B (mm) | a (mm) | P (KN) | \(K_H\) (MPa·m\(0.5\)) | \(K_h\) (MPa·m\(0.5\)) |
|------------|-----------|-----------|---------------|--------|--------|--------|--------|-----------------|-----------------|
| Sand#1     | X1        | 2325      | Model-I       | 25.06  | 20.53  | 16.59  | 2.708  | 0.574           | /               |
|            |           |           | Model-II      | 25.13  | 20.57  | 16.74  | 1.551  | 0.709           | /               |
| Sand#2     | X2        | 2412      | Model-I       | 25.01  | 20.21  | 17.25  | 3.792  | 0.818           | /               |
|            |           |           | Model-II      | 25.02  | 19.85  | 17.25  | 2.012  | 0.956           | /               |
| Sand#3     | X3        | 2416      | Model-I       | 25.22  | 20.05  | 16.60  | 2.013  | 0.436           | /               |
|            |           |           | Model-II      | 25.18  | 20.50  | 16.84  | 1.828  | 0.838           | /               |
| Sand#4     | X4        | 2367      | Model-I       | 25.07  | 20.73  | 17.36  | 3.702  | 0.778           | /               |
|            |           |           | Model-II      | 25.09  | 20.30  | 16.65  | 2.085  | 0.967           | /               |
propagation of a hydraulic fracture along the natural fracture. The coefficient \( K_h \) can be introduced to define the horizontal principal stress difference (Equation 14). The results are shown in Table 7.

\[
K_h = \frac{\sigma_H - \sigma_h}{\sigma_h},
\]

(14)

where \( K_h \) is the horizontal principal stress difference coefficient, \( \sigma_H \) [MPa] is the maximum horizontal principal stress, and \( \sigma_h \) [MPa] is the minimum horizontal principal stress.

| Categories | Well name | Depth (m) | Accumulative natural fracture length (mm) | Average natural fracture width (mm) |
|------------|-----------|-----------|------------------------------------------|----------------------------------|
| Sand#1     | X1        | 2325      | 21.2                                     | 0.8                              |
| Sand#2     | X2        | 2412      | 26.3                                     | 1.2                              |
| Sand#3     | X3        | 2416      | 18.4                                     | 1.0                              |
| Sand#4     | X4        | 2367      | 13.7                                     | 0.2                              |

**FIGURE 4** 3-D reconstruction images of cores based on CT scan: (A) Sand#1, (B) Sand#2, (C) Sand#3, and (D) Sand#4

**TABLE 6** Parameters of natural fracture

**FIGURE 5** P-wave velocity along with changing angles
2.5.3 | Fracture barrier

Fracture barrier refers to the prevention of a neighboring barrier layer on a reservoir layer because the minimum horizontal principal stress of the former is generally greater than that of the latter (Figure 6). If the minimum horizontal principal stress difference between the barrier layer and the reservoir layer is small, the fracture height will not be controlled effectively, which will lead to insufficient stimulation of a horizontally distributed gas reservoir. Fracture barrier can be described by the minimum horizontal principal stress difference (Equation 15). It is clear that a greater minimum horizontal principal stress difference results in a larger SRV value. That is to say, fracture barrier is a positive index of fracability. In addition, the minimum horizontal principal stress of the barrier layer is also determined based on the AE experiment. The results are shown in Table 8.

\[
\Delta \sigma_h = \sigma_{h1} - \sigma_{h2},
\]

where \(\Delta \sigma_h\) [MPa] is the minimum horizontal principal stress difference between the barrier layer and the reservoir layer, \(\sigma_{h1}\) [MPa] is the minimum horizontal principal stress of the barrier layer, and \(\sigma_{h2}\) [MPa] is the minimum horizontal principal stress of the reservoir layer.

### Table 7 Horizontal principal stress results

| Categories | Well name | Depth (m) | \(\phi\) (%) | \(\alpha\) | \(P_h\) (MPa) | \(K_H\) (MPa) | \(K_h\) (MPa) | \(\sigma_h\) (MPa) | \(\sigma_k\) (MPa) | \(K_h\) |
|------------|-----------|-----------|--------------|--------|-------------|-------------|-------------|--------------|--------------|--------|
| Sand#1     | X1        | 2325      | 9.8          | 0.607  | 23.25       | 45.10       | 28.60       | 59.21        | 42.71        | 0.386  |
| Sand#2     | X2        | 2412      | 7.17         | 0.549  | 24.12       | 51.88       | 31.74       | 65.12        | 44.98        | 0.448  |
| Sand#3     | X3        | 2416      | 10.92        | 0.627  | 24.17       | 67.99       | 36.28       | 83.14        | 51.43        | 0.617  |
| Sand#4     | X4        | 2367      | 9.71         | 0.605  | 23.67       | 53.75       | 31.07       | 68.07        | 45.39        | 0.500  |

### Table 8 Results of the minimum horizontal principal stress difference between the barrier layer and the reservoir layer

| Categories | Well name | Layer type | Depth (m) | \(\sigma_h\) (MPa) | \(\Delta \sigma\) (MPa) |
|------------|-----------|------------|-----------|-------------------|----------------------|
| Sand#1     | X1        | Reservoir  | 2325      | 42.71             | -0.44                |
|            |           | Barrier    | 2329      | 42.27             |                      |
| Sand#2     | X2        | Reservoir  | 2412      | 44.98             | 0.49                 |
|            |           | Barrier    | 2414      | 45.47             |                      |
| Sand#3     | X3        | Reservoir  | 2416      | 51.43             | 5.95                 |
|            |           | Barrier    | 2418      | 57.38             |                      |
| Sand#4     | X4        | Reservoir  | 2367      | 45.39             | 9.05                 |
|            |           | Barrier    | 2370      | 54.44             |                      |

### Figure 6 Schematic of a fracture barrier

### 3 | COMPREHENSIVE FRACABILITY EVALUATION METHODS AND MODELS

#### 3.1 Principles of analytic hierarchy process (AHP)

Analytic hierarchy process (AHP) was invited by Saaty and has been widely used as a decision-making tool based on multiple criteria. AHP helps incorporate a group consensus and as many influencing factors as possible (not more than nine) can be included in the AHP model. AHP not only reflects the researchers’ subjective understanding but also reflects the objective results. We adopt AHP to quantitatively evaluate the fracability of the four reservoir intervals in the Jinshan gas field. Generally, the application of AHP involves the following steps (Figure 7):

1. The hierarchy structure model of the problem is constructed. Selecting factors with the greatest influence factors
on the problem is crucial, and the factors must be structured in a hierarchy of different levels constituting goal, criteria, and alternatives.

2. A judgment matrix that characterizes the importance of one factor compared with another factor is created based on the experience and judgment of experts.

3. The judgment matrix is optimized and the weight coefficient of each selected factor are calculated.

4. Candidates are evaluated using the AHP equations.

3.2 Normalization of the influencing factors

In this research, the goal refers to the reservoir fracability. The influencing factors can be divided into those with positive index and negative index. The higher the positive index is, the higher the reservoir fracability is. Conversely, the higher the negative index is, the lower the reservoir fracability is. Categorized results of all the influencing factors are shown in Table 9. AHP requires all influencing factors to be normalized in the range from 0 to 1. Equation (16) is used to normalize the positive indexes, and Equation (17) is used to normalize the negative indexes.

\[
S = \frac{X - \min X}{\max X - \min X} \quad (16)
\]

\[
S = -\frac{\max X - X}{\max X - \min X} \quad (17)
\]

where \(S\) is the normalized factor, \(\max X\) is the maximum of the influencing factor, and \(\min X\) is the minimum of the influencing factor.

Table 9 lists all the influencing factors included in this research, in which some factors like mechanical brittleness, brittle mineral content, and horizontal stress difference coefficient do not need to be normalized as they are already dimensionless numbers ranging from 0 to 1. However, the other influencing factors should be normalized. According to large number of existing experimental data from the Yingcheng formation, Jinshan gas field, the range of each normalized factor can be determined. Specifically, the max \(X\) of cohesion is 40 and its min \(X\) is 4; the max \(X\) of IFA is 50 and its min \(X\) is 35; the max \(X\) of UCS is 252 and its min \(X\) is 11; the max \(X\) of minimum horizontal stress difference is 12 and its min \(X\) is -2; the max \(X\) of Model-I toughness is 1.15 and its min \(X\) is 0.23; the max \(X\) of Model-II toughness is 1.32 and its min \(X\) is 0.21; the max \(X\) of average natural fracture width is 1.5 and its min \(X\) is 0; the max \(X\) of accumulative natural fracture length is 42.3 and its min \(X\) is 0. Beyond that, the average value of normalized average natural fracture width and accumulative natural fracture length is adopted to represent the developed levels of natural fractures comprehensively. Similarly, the average value of normalized Model-I toughness and Model-II toughness is adopted to represent fracture toughness comprehensively. Based on AHP theory, the number of the influencing factors should be not more than nine to ensure the distinction of each factor. In this research, there are nine influencing factors that were taken as a primary consideration, which just meets the number requirement of AHP factors. The normalized results of each factor are shown in Table 10.

3.3 Factor correlation analysis

Mutual effects may exist between different influencing factors of reservoir fracability. Therefore, the mutual effects of each pair of factors need to be analyzed, and the factors with remarkable mutual effects should be considered to remove from the AHP model. Correlation analysis is an effective method to determine the mutual effects between the influencing factors. Pearson's correlation coefficient was used to represent the correlation of each pair of factors. It can be calculated by the following equation.

\[
r = \frac{\sum XY - \frac{\sum X \sum Y}{N}}{\sqrt{\left(\sum X^2 - \frac{(\sum X)^2}{N}\right) \left(\sum Y^2 - \frac{(\sum Y)^2}{N}\right)}}. \quad (18)
\]
where \( r \) is Pearson’s correlation coefficient, \( X \) and \( Y \) are the values of arbitrary two group of data, and \( N \) is the number of specimens.

Here, \( r \) varies from -1 to 1. When \( |r| \) is larger, the correlation between \( X \) and \( Y \) are stronger. \( r = 0 \) represents complete uncorrelation; \( 0 < |r| \leq 0.3 \) represents slight correlation; \( 0.3 < |r| \leq 0.5 \) represents real correlation; \( 0.5 < |r| \leq 0.8 \) represents significant correlation; and \( 0.8 < |r| \leq 1 \) represents high correlation.

The correlation coefficient matrix can be described as:

\[
A(r_{ij}) = \frac{\text{cov}(i,j)}{\sqrt{\text{cov}(i,i) \cdot \text{cov}(j,j)}}, \quad (19)
\]

where \( \text{cov}(i,j) \) is the covariance between the \( i \)-th factor and the \( j \)-th factor. The order of factors in the equation corresponds with the order of factors in Table 10.

According to experimental data from the Yingcheng formation, Jinshan gas field. Fifteen groups of data specimen are selected to calculate the Pearson’s correlation coefficient of each pair of factors. Then, a \( 9 \times 9 \) symmetrical correlation coefficient matrix \( A(r_{ij}) \) can be obtained:

\[
A(r_{ij}) = \begin{pmatrix}
1 & -0.141 & -0.0450 & 0.3282 & -0.2597 & 0.0148 & -0.1134 & 0.1956 & -0.2859 \\
-0.141 & 1 & -0.1474 & 0.2442 & -0.3409 & -0.2255 & -0.0239 & 0.0504 & 0.1408 \\
-0.0450 & -0.1474 & 1 & -0.3904 & 0.8520 & -0.0573 & -0.0840 & -0.1998 & -0.2031 \\
0.3282 & 0.2442 & -0.3904 & 1 & -0.3205 & 0.1162 & 0.7698 & 0.1957 & -0.0087 \\
-0.2597 & -0.3409 & 0.8520 & -0.3205 & 1 & 0.0510 & 0.2033 & -0.2093 & -0.0579 \\
0.0148 & -0.2255 & -0.0573 & 0.1162 & 0.0510 & 1 & -0.1164 & -0.5845 & -0.3254 \\
-0.1134 & -0.0239 & -0.0840 & 0.7698 & 0.2033 & -0.1164 & 1 & -0.2076 & -0.0526 \\
0.1956 & 0.0504 & -0.1998 & 0.1957 & -0.2093 & -0.5845 & -0.2076 & 1 & 0.3658 \\
-0.2859 & 0.1408 & -0.2031 & -0.0087 & -0.0579 & 0.3254 & -0.0526 & 0.3658 & 1
\end{pmatrix}. \quad (20)
\]

It can be seen that the vast majority of elements of \( A(r_{ij}) \) are <0.5, which means the corresponding correlation are slight. However, there are two pair of elements, \( r_{35} = r_{53} = 0.8520 \) and \( r_{47} = r_{74} = 0.7698 \), which are much greater than other elements. It means that the correlation between cohesion and UCS, and the correlation between IFA and fracture toughness are both relatively remarkable. The above relationships are analyzed based on knowledge of rock mechanics:

1. When the rock cohesion is greater, the consolidation between rock granules will be stronger, which means the rock is more difficult to fracture, and the compressive strength is greater. Therefore, it shows a strong positive correlation between cohesion and UCS.
2. When the IFA is smaller, the fracture planes are easier to slide. For fracture toughness, Model-II toughness is an important parameter to affect the rock’s ability to slide. When Model-II toughness is lower, more shear slip actions will occur in both hydraulic fractures and natural fractures. Therefore, it shows a strong positive correlation between IFA and fracture toughness.

Obviously, cohesion influences the reservoir fracability more significantly than UCS, and fracture toughness is a more important factor than IFA according to principles of rock mechanics. Therefore, the UCS and IFA are considered to remove from AHP model. Then the number of influencing factors included in AHP model is decreased to seven.

| Effects | Mechanical brittleness | Mineral brittleness | Cohesion | IFA | UCS | Natural fracture | Fracture toughness | Horizontal stress difference | Fracture barrier |
|---------|------------------------|---------------------|----------|-----|-----|------------------|---------------------|-----------------------------|----------------|
| Positive | ✓                      | ✓                   | ✓        | ✓   | ✓   | ✓                | ✓                   | ✓                           | ✓              |
| Negative| ✓                      | ✓                   | ✓        |     |     |                   |                     |                             |                |

### 3.4 Weight coefficient

In AHP model, an approach for pair-wise comparisons was used, as it provides a method to calibrate the numeric scale of quantitative measurements. A matrix \( P = (a_{ij}) \) is introduced to define the importance of factor \( i \) compared with factor \( j \) on the reservoir fracability (Table 11). The integers range from 1 to 9, and their reciprocals were used to represent the measured results, as shown in Table 11. To apply AHP, the importance of influencing factors are compared and scaled.
according to both the previous viewpoint\textsuperscript{19} and experts’ suggestions. Then a judgment matrix \( P = (a_{ij}) \) can be constructed, as shown in Table 12.

The judgment matrix is essential for calculating the weight of each factor. Because the judgment is influenced by the complexity of the objective world and the diversity of people's understanding of problems, the judgment matrix may be inconsistent. For example, if factor A is three times more important than factor B, and factor B is two times more important than factor C, then it can be deduced that factor A is six times more important than factor C based on the first two comparisons. However, factor A may be slightly more important and even less important than factor C when the comparison is made only between A and C. Therefore, in order to improve the consistency of judgment matrix, a transfer matrix was introduced in the AHP model (Equations 21 and 22), and a new judgment matrix which is equivalent to the original can be established (Equation 23).\textsuperscript{34}

\[
C_{ij} = \lg a_{ij}
\]  
(21)

\[
d_{ij} = \sum_{k=1}^{n} (C_{ik} - C_{jk})/n
\]  
(22)

\[
P_{ij}^* = 10^{d_{ij}},
\]  
(23)

where \( a_{ij} \) is the original judgment matrix, \( d_{ij} \) is the transfer matrix, \( P_{ij}^* \) is the equivalent judgment matrix, and \( n \) is the matrix order.

Consistency check is an important work to determine whether the judgment matrix used in AHP satisfies the requirement of consistency. The consistency ratio proposed by Saaty\textsuperscript{32} was used to judge whether the consistency of judgment matrix can be accepted. The equations are as follows:

\[
CI = \frac{\lambda_{\text{max}} - n}{n-1}
\]  
(24)

\[
CR = \frac{CI}{RI}.
\]  
(25)

where CR is the consistency ratio, CI is the consistency index, \( \lambda_{\text{max}} \) is the maximum eigenvalue of judgment matrix, \( n \) is judgment matrix order, and RI is the average consistency index of sample matrix.

According to Saaty’s research results, RI are given in Table 13. Here, \( n = 7 \), RI = 1.32. Generally, the closer the CR gets to 0, the consistency of judgment matrix is better.

The CR of both the original judgment matrix and the equivalent judgment matrix were calculated. The CR of original judgment matrix is 0.0461, and the CR of equivalent judgment matrix decreases to only \( 2.98 \times 10^{-5} \), which
can be regarded almost as complete consistency. Therefore, the introduction of transfer matrix is very useful in the AHP model.

The weight coefficient of each factor can be calculated:

\[
\bar{w}_i = \sqrt[n]{\prod_{j=1}^{n} P_{ij}^n}
\]

\[
\tilde{w}_i = \frac{\bar{w}_i}{\sum_{k=1}^{n} \bar{w}_k}
\]

where \( \tilde{w}_i \) is the \( i \)-th normalized weight coefficient (\( i = 1, 2, 3, \ldots, n \)).

Based on the above methods, the array of normalized weight values for each influencing factor can be calculated using Equation (28).

\[
W = [w_1, w_2, w_3, w_4, w_5, w_6, w_7]^T = [0.2758, 0.2758, 0.1751, 0.1122, 0.0725, 0.0527, 0.0360]^T
\]

where the weight values \( w_1 \) to \( w_9 \) correspond to natural fracture, mechanical brittleness, mineral brittleness, horizontal stress difference, fracture toughness, cohesion, and fracture barrier, respectively.

3.5 | Fracability evaluation

It has been assumed that there are \( n \) fracturing reservoir intervals and each one has \( m \) influencing factors. Based on the fuzzy mathematical theory, a limited set that includes all reservoir intervals can be created (Equation 29). Afterwards, \( m \) linear orders for each of the \( n \) reservoir intervals can be constructed as \( L_1, L_2, L_3, \ldots, L_m \).
The order \( L_i \) \((i = 1, 2, \ldots, m)\) is arrayed depending on whether the influencing factor is positive or negative. For a positive factor, the \( n \) fracturing reservoir intervals \((U_1 \text{ to } U_n)\) are arrayed in descending order. Conversely, for a negative factor, they are arrayed in ascending order. Under Blin and Satterthwaite’s theory,\(^{35}\) a fuzzy matrix \((R = (r_{jk}))\) that helps make the final decision can be constructed (Equation 30). In the matrix, the sum of elements in the \( j \)-th row represents the fracability of the \( j \)-th fracturing reservoir interval (Equation 34). The higher the coefficient is, the greater fracability of the corresponding reservoir intervals. This means that the reservoir interval with higher fracability coefficient will theoretically obtain more complex fracture networks and larger SRV.

\[
U = \{U_1, U_2, \ldots, U_n\}
\]

\[
R = [r_{ij}]_{n \times n} \quad (i, j = 1, 2, 3, \ldots, n)
\]

\[
r_{ij} = u(U_j, U_i) = \sum_{i=1}^{m} w_i \cdot u_{L_i}(U_j, U_k)
\]

\[
u_{L_i}(U_j, U_k) = \begin{cases} 
1 & (U_j \text{ is superior to } U_k \text{ in order } L_i) \\
0.5 & (U_j \text{ is equal to } U_k \text{ in order } L_i) \\
0 & (U_k \text{ is superior to } U_j \text{ in order } L_i)
\end{cases}
\]

\[
r_{ij} = 0 \quad (j = k)
\]

\[
r_{jk} + r_{kj} = 1 \quad (j \neq k)
\]

\[
F(j) = \sum_{k=1}^{n} r_{jk},
\]

where \( U \) is the limited universe of discourse set, \( R \) is the fuzzy matrix, and \( F(j) \) is the fracability coefficient.

The calculated results of \( R \) and \( F(j) \) are as follows:

\[
R = \begin{pmatrix}
0 & 0.4125 & 0.1649 & 0.5132 \\
0.5875 & 0 & 0.6901 & 0.7164 \\
0.8351 & 0.3099 & 0 & 0.4885 \\
0.4868 & 0.2836 & 0.5115 & 0
\end{pmatrix}
\]

\[
[F(1), F(2), F(3), F(4)] = [1.0906, 1.9940, 1.6335, 1.2819]
\]

According to the calculating results of fracability coefficient (Equation 36), the fracability coefficients of the four fracturing reservoir intervals in the Jinshan gas field are obviously different. The fracability of the four intervals can be ranked from high to low as well X2 (2412 m), well X3 (2416 m), well X4 (2367 m), and well X1 (2325 m). Among them, the interval of well X2 (2412 m) has the best fracability. Theoretically, the largest SRV and the highest gas production may be obtained in well X2 (2412 m). On the contrary, well X1 (2325 m) and well X4 (2367 m) have the worst fracability.

4 | FIELD APPLICATION

Well X1, X2, X3, and X4 are the appraisal wells drilled in Sinopec’s Jinshan gas field in southern Songliao Basin, China. These wells are drilled in the Huoshiling formation to depths of 3129 m, 3206 m, 3800 m, and 3500 m, respectively. In recent years, Sinopec has moved to implement fracturing in the shallower Yingcheng formation (2300–2450 m), which bears rich naturally fractured sandstone gas resources.

To validate the feasibility of the proposed evaluation method based on AHP, the four reservoir intervals of well X1 (2325 m), well X2 (2412 m), well X3 (2416 m), and well X4 (2367 m) in the Yingcheng formation were conducted perforation. Volumetric fracturing treatment was all successfully implemented with approximately the same construction parameters in each well. The construction curves are as shown in Figure 8. The average amount of expended guar gum fracturing fluid reached 910 m³, including 320 m³ of prepad fluid, 573 m³ of proppant-carrying fluid, and 17 m³ of displacement fluid. Averagely, 87 m³ of (20-40)-mesh ceramic proppant were used during the proppant-carrying fluid stage, and 3 m³ of 100-mesh ceramic powder was designed as three proppant slugs to polish the perforated hole and fractures during the prepad fluid stage. The injection of proppant went very smoothly and the average proppant-fluid ratio reached 18.8%. The prepad fluid rate and proppant-carrying fluid rate were both near 7 m³/min in each well. The features of the construction curves are analyzed as follows:

1. The tubing pressure curves of well X1, well X2, and well X3 all fluctuated violently, and the breakdown pressure of them was all indistinct. It means that a number of micro natural fractures were developed in the three reservoir intervals and they were successfully opened by fracturing fluid. Specifically, there are three sharp declines in the tubing pressure curve of well X2, and it can be deduced that the natural fractures were

| n | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| RI | 0 | 0 | 0.58 | 0.9 | 1.12 | 1.24 | 1.32 | 1.41 | 1.45 |
much more developed and more complex fracture networks were generated in the reservoir interval of well X2 (2412 m) during fracturing.

2. The tubing pressure curve of well X4 was smoothest among the four tubing pressure curves, especially in the prepad fluid stage. It means that the natural fractures were badly developed in the reservoir interval of well X4 (2367 m).

3. The analysis results of construction curves were in accordance with evaluation results of 3-D core reconstruction on developed level of natural fractures.

The surface choke with inner diameter of 8 mm was all used in gas production test of each well. According to production data, the initial gas production of well X1 (2325 m), well X2 (2412 m), well X3 (2416 m), and well X4 (2367 m) was 9820, 26 270, 19 620, and 9170 m³ per day, respectively. We can see that well X2 (2412 m) not only obtained the largest gas production but also the highest tubing pressure from gas production test. From Figure 9, the gas production results agree with the calculated results of fracability coefficient based on the AHP model. In conclusion, the field application results proved that the comprehensive model for fracability evaluation in naturally fractured sandstone reservoirs proposed in this paper was objective and feasible.

5 | CONCLUSION

This paper develops an integrated petrophysics and geomechanics approach for characterizing the reservoir fracability in naturally fractured sandstone reservoirs. A quantitative AHP model for reservoir fracability evaluation was proposed based on a series of experiments, and this model was verified.
to be objective in field application. The main conclusions are as follows:

1. A comprehensive evaluation model for fracability evaluation in naturally fractured sandstone reservoirs was proposed using the analytic hierarchy process (AHP). This model has primitively considered nine important influencing factors including such as natural fracture. In the model, the maximum and minimum of the influencing factors were taken into account in the process of standardization in order to make the normalized results more practical and meaningful. The UCS and IFA were removed from the AHP model based on the results of factor correlation analysis. A transfer matrix was introduced to improve the consistency of judgment matrix, so that the calculated weight coefficients are more objective. In addition, a fuzzy matrix was constructed to help evaluate fracability more systematically instead of using a simpler linear weighting method.

2. The contribution of influencing factors (mechanical brittleness, mineral brittleness, cohesion, natural fracture, fracture toughness, horizontal stress difference, and fracture barrier) to reservoir fracability was analyzed. The significance of these factors on reservoir fracability was ranked based on AHP method.

3. The proposed model was applied in a quantitative evaluation of four naturally fractured sandstone reservoir intervals in the Jinshan gas field. To obtain the values of the influencing factors, several experimental tests, including compression test, X-ray diffractometer measurement, SNBD test, X-ray CT scan, and acoustic emission test were conducted on the cores drilled from the four reservoir intervals. The results show that the fracability rank (from high to low) of the four intervals was well X2 (2412 m), well X3 (2416 m), well X4 (2367 m), and well X1 (2325 m). Among them, the fracability coefficient of well X2 reached 1.994, which is obviously greater than that of the other reservoir intervals.

4. To verify the model, the four wells were all implemented hydraulic fracturing. The fracturing construction curves showed that the reservoir interval with more fluctuated tubing pressure curve has more developed natural fractures. The results of gas production tests showed that daily gas production and tubing pressure are higher in the reservoir interval with better fracability. This suggests that the field test data coincide with the results of the proposed model.

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