Analysis of the Key Factors Affecting the Productivity of Coalbed Methane Wells: A Case Study of a High-Rank Coal Reservoir in the Central and Southern Qinshui Basin, China

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ABSTRACT: In the present study, three CBM blocks in the central and southern Qinshui Basin, China, including Fanzhuang, Zhengzhuang, and Changzhi blocks, were selected. Combined with the data, such as the physical properties of coal reservoirs, logging, hydrofracture operation, injection/drawdown well testing, microseismic fracture monitoring technology, and over 2000 days gas production rate, the key factors affecting the gas production rate of CBM wells were analyzed comprehensively and systematically. Unimodal and bimodal models can be identified according to the long-term gas production rate data. The unimodal model corresponds to a declining pump pressure curve, meaning that caprock integrity is destroyed during hydrofracture operations, commonly causing poor gas production performance. The bimodal model is associated with fluctuating-rising and stable pump pressure curves, indicating good hydrofracture consequences. On the premise of the relatively high gas content, the gas saturation/critical-reservoir pressure ratio, permeability, and coal deformation are the major geological factors that affect the long-term gas production performance of CBM wells. Engineering factors, including pollution by the drilling fluid and cement paste, the type of the fracturing fluid, tonstein intercalation, coal deformation, and in situ stress, affect gas production performances via the following four mechanisms: the effect of hydrofracture operations on caprock integrity, the effect of fluids pumped on the pore-fracture system, the initiation and propagation of artificially induced fractures, and the performances of proppants pumped. This work can provide guidelines for the optimization and development of high-rank CBM blocks.

INTRODUCTION

Coalbed methane (CBM) resources are abundant in China after Russia and Canada. CBM can reach $36.81 \times 10^{12}\text{m}^3$ with a depth of less than 2000 m in 42 main coal-bearing basins, mainly in the Ordos Basin $(9.86 \times 10^{12}\text{m}^3)$ and Qinshui Basin $(3.95 \times 10^{12}\text{m}^3)$. CBM, as a clean and important supplementary energy, plays a significant role in reducing the risk of coal and gas outburst, optimizing energy construction, and mitigating climate change. Additionally, CBM reservoirs are regarded as potential strata for CO₂ sequestration, which also attracts extensive attention in recent years. Hence, accelerating CBM industrialization is of great significance.

Since the 1990s, seven CBM exploratory wells were drilled in the Fanzhuang block and continuous commercial gas flow was achieved. For accelerating CBM commercialization, the number of CBM wells showed explosive enhancement, approximately 17,000 by the end of 2017, of which more than 16,000 belonged to gas-producing wells. Consequently, annual CBM production gained a marked breakthrough. CBM production in 2017 reached $48.3 \times 10^8\text{m}^3$ in China. Nonetheless, achieving the annual CBM production of $100 \times 10^8\text{m}^3$ would not be accomplished by 2020 according to the “13th Five-year Plan” for CBM development and utilization. Moreover, the average gas production rate of a single CBM well grows slowly. For our three CBM blocks selected, the average gas production rate of a single CBM well ranged from 500 to 3500 m³/d in the Fanzhuang block, from 200 to 2000 m³/d in the Zhengzhuang block, and from 200 to 1500 m³/d in the Changzhi block. It was less than 3000 m³/d for most CBM wells, even only hundreds of cubic meters per day in some CBM wells, belonging to moderate- to low-yield classes on the basis of the capacity-grading scheme proposed by Zhang. As a result, digging problems of lag in CBM development, analyzing possible reasons, and instituting corresponding measures are highly urgent to achieve their maximum potential of gas productivity.

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Qinshui Basin, as the earliest and most successful CBM commercial development demonstration area of high-rank coal in China (vitrinite reflectance $R_o$ more than 2.0%), is paid extensive attention to optimizing favorable blocks, identifying the key factors affecting gas productivity, and evaluating and forecasting gas production performance to achieve the maximum production potential of CBM wells in these prioritized blocks. Based on the physical parameters of CBM wells, such as pore-fracture distributions, gas content, gas saturation, permeability, vitrinite reflectance, coal thickness, burial depth, etc., the optimization of the favorable block is conducted using mathematical statistics such as gray correlation analysis, analytic hierarchy process, fuzzy mathematical method, and some combined methods, namely, analytic hierarchy process—fuzzy mathematical method. However, the resulting optimization of favorable blocks is largely dependent on the representativeness of sampling, and thus, commonly, the resulting optimization is just a reference and carries a degree of risk for CBM exploration and development. The identification of key factors affecting gas productivity is carried out via geological analogy methods using gas production rate data, the physical properties of coal reservoirs, hydrofracture operation parameters, and so on, although they are expensive and time-consuming. According to previous publications, factors affecting the gas production rate of CBM wells are divided into geological and engineering factors. Geological factors include the depositional environment, structural setting, macroscopic coal petrography, hydrodynamic distribution, sealing ability of the roof, buried depth, coal thickness, gas content, permeability, fracture characteristics, in situ stress, reservoir pressure, critical-reservoir ratio, and critical desorption pressure. Engineering factors include the liquid column height, volume of fracturing fluids and proppants, equivalent drainage radius, fluid velocity sensitivity due to the generation of coal fines, decline rate of working fluid level during the initial production phase, depressurization rate, and drainage scheme. Concerning gas productivity evaluation and forecast, a number of productivity models are established, mainly permeability and hydrofracture models, to more realistically uncover the real CBM production progress. However, there is no denying that these productivity models, more or less, involve ideal assumptions, even ignore unknown factors beyond at-present understanding because the CBM reservoir has a unique and complex flow mechanism and production scheme. Therefore, there are still some errors using these models to predict gas productivity. Although some associated works on the factors influencing CBM productivity have been reported, there are still some drawbacks. (1) The gas production time of CBM wells selected is relatively short, in most cases, only a few hundred days. Relatively short gas production data is apparently hard to reflect their real productivity, especially of some CBM wells with a relatively long single-phase flow stage. So, the effect of some factors on gas production possibly was enlarged or shrunk, and even some controversial conclusions can be drawn. (2) The effect of tonstein intercalation in the coal reservoir on gas production is rare. (3) Concerning engineering factors, it is blurry and hard to evaluate hydrofracture consequences using only some parameters like the volume of fracturing fluids and proppants. Therefore, the evolution of induced fractures regarded as a more valuable index for
evaluating hydrofracture consequences is wise and reasonable. In the present study, engineering factors refer to the factors that affect the evolution of induced fractures.

Based on the above-mentioned knowledge, in the present study, the physical properties of coal reservoir, logging curves, hydrofracture stimulation parameters, microseismic fracture monitoring technology, extraction technology, and gas production data over 2000 days from three CBM blocks in central and southern Qinshui Basin, China, are used to comprehensively and systematically analyze key factors that affect gas production rate among different CBM wells and blocks, aiming to provide guidelines for the optimization and development of other high-rank CBM blocks.

2. RESULTS

Concerning the gas production rate in these three CBM blocks, the Fanzhuang block is the highest, 500−3500 m³/d, followed by the Zhengzhuang block, 200−2000 m³/d, and the Changzhi block is the lowest, 200−1500 m³/d. Specifically, the south is higher than the north in the Fanzhuang block, the southwest is higher than the rest of the Zhengzhuang block, and the north is higher than the south in the Changzhi block. Because the extraction time of CBM wells from the Changzhi block (100−650 d) is relatively shorter compared with the life span of CBM wells, not reflecting the real productivity of CBM wells, gas production data of CBM wells in the Changzhi block are not adopted.

2.1. Gas Production Rate Characteristics of CBM Wells. According to long-term practical gas production rate curves, two types can be identified: unimodal model (Figure 1a) and bimodal model (Figure 1b−d). The gas production rate curves from Tao et al.14 and Kang et al.31 also supported this classification scheme. The bimodal model can be further divided into three types according to first-peak and second-peak gas production rates. Regarding extraction time, the second peak is significantly greater than the first peak except for the unimodal model. The unimodal model corresponds to the declining pump pressure curve (Figure 2). Their average gas production rates are low, in general, less than 800 m³/d. Decreasing pump pressure curves indicate that the integrity of caprock (or the sealing of caprock) is destroyed and subsequently gas emission occurs via induced migration channels, resulting in low gas production rate, even no gas production rate within the first-peak extraction time. Therefore, it is deduced that the first-peak gas production rate is, to a large extent, largely dominated by hydrofracture stimulation. Good stimulation consequences are the premise of achieving excellent gas production performance. The optimization of hydrofracture parameters and associated technology should be taken enough consideration to ensure the integrity of coal caprock.

2.2. Water Production Rate Characteristics of CBM Wells. Based on the statistical results, the cumulative water production of CBM wells ranges from 438.9 to 6328.7 m³ in the Fanzhuang block, from 261.2 to 1389.5 m³ in the Zhengzhuang block, and from 256.0 to 26878.1 m³ (more than 3000 m³ for most of the CBM wells) in the Changzhi block, although the extraction time is relatively shorter. As shown in Figure 3, water production rates of C12 and C27 CBM wells in the Changzhi block are very high, whose accumulation water productions are up to 34650.0 and 26878.1 m³, while accumulation gas productions are only 51057 and 63873 m³, that is, the corresponding gas production rates are only 56.0 and 103.4 m³/d, respectively. Zhao et al.30 also observed similar high water and low gas production rates of CBM wells in the Ordos Basin, China. A high water production rate is a crux of the low gas production rate in the Changzhi block. As a matter of fact, the average moisture content in coal cores from the Changzhi block is less than 1.0% (Table 1), and thus, we infer that the high water production rate is closely related to the integrity destruction of coal caprock due to hydrofracture operation.

3. DISCUSSIONS

Although CBM resources are abundant in China, porosity and permeability of coal seams are commonly less than 10% and 1 mD, respectively,44,45 and the pressure coefficient of the coal seam is relatively low.46 Commercial gas flow can be only achieved after hydrofracture operation. Therefore, the physical properties and hydrofracture technology jointly control the gas production rate of CBM wells.

3.1. Geological Factors. 3.1.1. Gas Content. Gas content is basic for CBM development. In previous publications, gas content plays a positive role in CBM development.25,30,31,47 However, there is no obvious positive correlation in the Fanzhuang block, even a negative correlation is found in the Zhengzhuang block between the gas content and gas production rate (Figure 4). This gives us a warning that the gas content may not be a dominant factor affecting the gas production rate when the gas content is relatively high, in particular.

In general, the gas content is positively proportional to the buried depth and thermal maturation, shown in Figures 5 and 6. The higher the coal rank, the greater the degree of thermal cracking coal,48 resulting in a higher gas content in coal when the sealing performance of caprock is high. Nevertheless, there is no positive correlation between $R_{0}$ and the buried depth, especially for Fanzhuang and Zhengzhuang blocks (Figure 7). If the high gas content results from the high sealing capacity of the increasing buried depth, in that way, the negative effect on the gas production rate of CBM wells due to the increasing buried depth is considerable (Figure 8). After all, permeability loss is high with increasing buried depth (Figure 9). To sum up, the gas content is not a major factor influencing the CBM.
development of high-rank coal when the gas content is up to an average of 19.47 and 21.33 cm³/g in the Fanzhuang block and Zhengzhuang block, respectively.

3.1.2. Gas Saturation and Critical-Reservoir Pressure Ratio. Gas saturation (Gₛ) refers to the ratio of measured gas content (Vₚ) and theoretical gas content (Vₜ) at in situ coal reservoir pressure (Pᵣ).⁴⁹,⁵⁰ Vₜ is calculated using the Langmuir adsorption isotherm equation, in which the Langmuir volume (V_L) and Langmuir pressure (P_L) are obtained using isothermal adsorption experiments. Correspondingly, the ratio of the critical desorption pressure (P_cd) and in situ reservoir pressure (Pᵣ) is obtained, called the

Table 1. Physical and Petrographic Properties of No. 3 Coal Reservoir in the Three CBM Blocks

| parameters       | Fanzhuang block | Zhengzhuang block | Changzi block |
|------------------|-----------------|------------------|---------------|
| physical properties |                 |                  |               |
| buried depth (m)  | 425–746/575     | 626–1260/886     | 529–1340/917  |
| thickness (m)     | 5.89–7.76/6.47  | 7.65–31.44/21.33 | 4.55–23.42/14.43 |
| gas content (cm³/g) | 11.15–22.14/19.47 | 3.33–31.44/8.00 | 1.32–10.06/4.16 |
| porosity (%)      | 4.16–22.09/14.48 | 4.43–10.90/6.48  | 2.30–13.00/5.93 |
| fracture density (strip/cm) | 3.39–7.30/4.76 | 0.74–1.91/1.24 | 0.51–1.60/0.87 |
| moisture (%)      | 0.98–2.25/1.43  | 11.42–22.05/14.33 | 9.79–21.63/12.14 |
| ash (%)           | 4.16–22.09/14.48 | 86.3–97.4/94.7 | 58.2–99.1/92.7 |
| organic component (%) | 90.8–96.6/94.8 | 53.6–89.2/70.5 | 37.4–90.6/72.4 |
| vitrinite (%)     | 54.2–85.5/72.5  | 14.5–45.8/27.5  | 10.8–46.4/29.5 |
| inertinite (%)    | 3.33–4.08/3.60  | 2.95–4.44/3.68  | 1.96–2.62/2.38 |
| vitrinite reflectance (%) | 3.39–7.30/4.76 | 0.74–1.91/1.24 | 0.51–1.60/0.87 |

“The values are presented as “minimum–maximum/average”.

Figure 3. Typical water production rate of CBM wells in the Changzi block.

Figure 4. Gas content correlating with the gas production rate.

Figure 5. Plot of R₀ versus gas content.

Figure 6. Plot of buried depth versus gas content.

Figure 7. Plot of R₀ versus buried depth.
critical-reservoir pressure ratio \( (P_{cd}/R) \). \( G_s \) and \( P_{cd}/R \) can be calculated using Formulas 1 and 2, respectively. The sketch map of the calculation of gas saturation and critical-reservoir pressure ratio is shown in Figure 10. The critical-reservoir pressure ratio reflects the alternation of reservoir energy and flow pattern. Commonly, gas saturation correlates positively and linearly with the critical-reservoir pressure ratio (Figure 11).

\[
G_s = \frac{V_R}{V_T} = \frac{V_R(P_R + P_L)}{(P_R \times V_L)} \quad (1)
\]

\[
P_{cd}/R = \frac{P_{cd}}{P_R} \quad (2)
\]

The gas production rate is positively proportional to gas saturation (Figure 12a) and the critical-reservoir pressure ratio (Figure 12b), respectively, indicating that gas saturation and the critical-reservoir pressure ratio can be used as key parameters for estimating the gas production rate of CBM wells. Generally, higher gas saturation and higher critical-reservoir pressure ratio of coal seam indicate the smaller pressure drop to reach the critical desorption pressure during CBM extraction.

In the initial stage of extraction, water single-phase flow dominates, and effective stress bore by coal skeleton gradually grows along with the output of the fracturing fluid or formation water, called stress sensitivity, giving rise to continuous permeability damage. The higher the gas saturation and critical-reservoir pressure ratio, the lower the permeability damage due to the smaller pressure drop at the same extraction scheme. Once the coal reservoir pressure is below \( P_{cd} \), gas desorption causes the coal matrix shrinking effect; meanwhile, the desorbed gas can share part stress, preventing continuous permeability damage, even offsetting previous permeability damage, and further enhancing the permeability of the coal seam. If gas saturation is more than 1, indicating that there is no depressurization and permeability damage in the initial process of extraction, the gas production rate of CBM wells is very considerable.

According to the findings of Tao et al., high initial reservoir pressures signify great preservation conditions rather than high gas contents. In theory, good preservation conditions mean high gas contents, which are conducive to CBM development. However, Zhao et al. observed that the low gas production rate of CBM wells is related to the high initial reservoir pressure in the Ordos Basin, China. This is due to that under similar sedimentary and tectonism, a high initial reservoir pressure corresponds to a deep buried depth. Because the critical-reservoir pressure ratio and gas saturation correlate positively with the gas production rate, using them to reflect great sealing capacity is more reasonable rather than the initial reservoir pressure.

3.1.3. Permeability. Coal permeability is a key parameter to estimate CBM exploration and development. In the present study, coal permeability and the fracture extension length are monitored by injection/drawdown well testing and microseism fracture monitoring technology, respectively. The detailed descriptions of calculating permeability by injection/drawdown well testing can be found in a previous publication. Microseism fracture monitoring technology is
based on a continuous P- and S-wave signal that is obtained using an arranged geophone detector far away from the noise source of the CBM well site near the surface, which aims to analyze fracture evolution in the time domain according to multiwave three-component data vector superposition, amplitude inversion calculation, and four-dimensional visualization fracture morphology interpretation technology.

Coal seams with higher permeability have a greater CBM yield (Figure 13); this is possibly because these coal seams are

Figure 13. Effect of coal permeability on the gas production rate.

more conducive to depressurization and energy transfer and include superior channels for gas migration. For instance, the FI well permeability is 0.91 mD, gas flow occurs only after 30 day backflow (200 m³/d), and the maximum gas production rate is up to 5496 m³/d. However, the F9 well permeability is only 0.02 mD, gas flow occurs after up to 130 day extraction (only 91 m³/d), and the maximum gas production rate is only 2391 m³/d. Additionally, as shown in Figure 14, there is a

Figure 14. Relationship between permeability and the fracture extension length.

positive correlation between coal reservoir permeability and the fracture extension length, which is possibly because the high-pressure fracturing fluid injected has smaller flow resistance and less energy loss during the fracturing operation, resulting in a longer fracture extension length.

There is a blurry correlation between permeability and the 40 month gas production rate of CBM wells, while a positive correlation between over 2000 days gas production rate and permeability in the present study (Figure 13). This indicates that the gas production rate at an early stage is largely dependent on hydrofracture stimulation but the long-term gas production rate is related closely to coal permeability.

3.1.4. Coal Deformation. Combined with core plugs and corresponding logging curves, coal deformation is interpreted. Coals with various degrees of deformation involve striking differences in the pore-fracture system and adsorption–desorption–diffusion–seepage characteristics.

In general, intact coal is dominated by some pores and endogenic fractures with poor connectivity. Also, the developed conditions of endogenic fractures are closely related to coal maceral, which usually develop vitrinite. Besides endogenic fractures, cataclastic coal includes well-developed exogenic fractures with good connectivity. Granulated coal is the product of brittle–ductile deformation, and thus, the number of exogenic fractures reduces sharply compared with cataclastic coal. Mylonitized coal is completely powdered due to long-term ductile deformation, which gives rise to the almost complete disappearance of endogenic and exogenic fractures, only well-developed pores. Therefore, granulated–mylonitized coal is regarded as the out-of-bound zone for CBM exploration and development due to the lack of gas migration channels of coal itself.

According to the results of fracture observation, both the fracture density and length are greater but the fracture width is narrower in the Zhengzhuang block than those in the Fanzhuang block (Table 2). For the Zhengzhuang block, relatively stronger tectonism causes an increase of fracture length and density, but the deeper buried depth results in a decrease in fracture width. For the Changzhi block, due to stronger and more complex tectonism, seriously powdered coal extremely developed. In addition, the buried depth is relatively deep, and therefore, the fracture length and width in the Changzhi block are minimal.

The pore-fracture system of coal significantly affects gas adsorption, desorption, diffusion, and seepage. With increasing coal deformation, methane adsorption capacity tends to increase due to increasing specific surface area. In that case, desorption becomes difficult. The greater the surface free energy coal, the more difficult the coal desorption. It is well known that the surface free energy of mylonitized coal is the highest, so only when enough potential energy is acquired, methane can be converted from the absorption state to the free state. Zhang et al. compared the Pdc values of coals with different degrees of deformation. Their results show that the Pdc values of intact coal and cataclastic coal (2.77 and 2.73 MPa) are notably higher compared with that of granulated–mylonitized coal (2.21 MPa). Concerning methane diffusion, an increasing tendency can be found from intact coal to mylonitized coal due to increasingly well-developed pores and excellent connectivity. With regard to seepage capacity, a trend of first increase and then decrease is found because of the differences of exogenous and endogenous fractures from intact coal to mylonitized coal, and the seepage capacity of cataclastic coal is the greatest. In general, the desorbed methane migrating to the

Table 2. Distribution Characteristics of Fractures in the Three CBM Blocks

| block     | length (cm) | width (µm) | density (strip/cm) |
|-----------|-------------|------------|--------------------|
| Fanzhuang | 2.30–5.73/4.05 | 6.88–54.33/18.54 | 3.39–7.30/4.83 |
| Zhengzhuang | 3.60–7.01/4.96 | 9.00–33.14/15.66 | 4.40–10.90/6.33 |
| Changzhi | 0.11–1.63/0.45 | 0.14–48/12.88 | 2.3–15/5.93 |
wellhole is a series process, including diffusion and seepage. Any obstacles to this series process during CBM migration are bound to affect the continual productivity of CBM wells. As coal deformation increases, the desorption capacity reduces, the diffusion property improves, and the seepage capacity first increases and then decreases. In summary, cataclastic coal is considered to be ideal for CBM development.

In addition, coal mechanical property weakens gradually with increasing deformation. The differences in mechanical properties among coals with different degrees of deformation will affect the fracturing consequences, which will be discussed in the following section.

3.2. Engineering Factors. Because an advanced and standard extraction technology is schemed, CBM wells selected are still in the commercial exploitation stage and the extraction time is more than 2000 days, even up to 3500 days. Thus, the effect of the extraction scheme on CBM well productivity can be ignored in the present study. Therefore, the engineering factors affecting the hydrofracture consequences will be demonstrated from the following four aspects: the effect of hydrofracture operations on the caprock integrity, the effect of fluids pumped on the pore-fracture system, the initiation and propagation of artificially induced fractures, and the performances of proppants pumped.

3.2.1. Pollution by the Drilling Fluid and Cement Paste. Drilling and completion are necessary for CBM development in China. During operation, drilling fluid and cement paste are inevitable to contact with coal reservoir. At the drilling stage, the diameter of the wellhole relates closely to coal deformation. In general, the stronger the coal deformation, the greater the borehole diameter (Table 3), which is due to that increasing plasticity is hard to stabilize a borehole, resulting in borehole collapse.

When drilling is completed, cement paste pumped at the completion stage causes secondary pollution to the coal reservoir. These reservoir damages caused by the drilling fluid and cement paste is irreversible, resulting in blocking the pore-fracture system of the coal reservoir near borehole zones. Moreover, when well completion is completed, the generation of a big-belly cement sheath increases the difficulty in perforation, as the strength of cement is much higher than that of coal.

3.2.2. Type of Fracturing Fluid. Hydrofracture consequences are related closely to the fracturing fluid used. Some pilot field tests to stimulate coal reservoirs have been conducted using first a clean fracturing fluid (stage I) and then an active water fracturing fluid (stage II), which can, to the most extent, avoid the effect of geological conditions and take only the effect of the fracturing fluid into consideration. The corresponding 11 year gas production performances of the F12 well are shown in Figure 15. At stage I, the gas production rate ranges from several dozens to 500 m³/d after clean

Table 3. Diameter Curves of Coals with Various Degrees of Deformation

| ID      | Diameter curves | Coal core plugs |
|---------|-----------------|-----------------|
| C9 CBM well | ![Diameter Curves](image1) | ![Coal Core Plugs](image2) |
| C6 CBM well | ![Diameter Curves](image3) | ![Coal Core Plugs](image4) |
| C25 CBM well | ![Diameter Curves](image5) | ![Coal Core Plugs](image6) |
| C17 CBM well | ![Diameter Curves](image7) | ![Coal Core Plugs](image8) |
fracturing fluid treatment. While at stage II, it is more than 2500 m$^3$/d after active water fracturing fluid treatment, although this CBM well is contaminated by the clean fracturing fluid up to 6.5 years. The lower production after hydrofracture stimulation using the clean fracturing fluid is attributed to residue damage due to incomplete gel breaking at low-temperature conditions.$^{72,73}$ Residues can block the pore throat, and this is fatal for these low-permeability coal reservoirs.

### 3.2.3. Tonstein Intercalation

A coal reservoir is regarded as a valid layer, but tonstein intercalation is considered to be an invalid layer for CBM development; hence, very little is known about the effect of tonstein intercalation on the gas production rate. Fortunately, we find a positive correlation between the tonstein intercalation thickness and the gas production rate (Figure 16).

![Figure 16. Plot of tonstein intercalation thickness versus gas production rate.](image)

According to logging technology, one or two layers of tonstein intercalation can be determined in No. 3 coal in the three CBM blocks. For instance, two tonstein intercalation layers at buried depths of 460.5–460.9 and 462.0–463.1 m are found in the F1 CBM well. Tonstein intercalation features with high density, high natural gamma value, and low gas content (Figure 17). Combining these notable characteristics, we can distinguish tonstein intercalation from a coal reservoir with high accuracy. However, tonstein intercalation is hard to discriminate only using a single parameter. For example, although a high natural gamma value at a buried depth of 657–658 m from the F6 CBM well is seen, there is no tonstein intercalation in coal, which is because the coal reservoir includes a certain percentage of clay minerals. For the F1 CBM well, the coal density and tonstein intercalation are comparable; however, there are two layers of tonstein intercalation in coal. Moreover, except for the F4 CBM well, tonstein intercalations in coal for F1 and Z22 CBM wells involve considerable gas contents. In summary, the accurate identification of tonstein intercalation in coal should integrate these three parameters.

As shown in Figure 18, Poisson’s ratio of tonstein intercalation is comparable to that of coal, but Young’s modulus of tonstein intercalation is significantly greater than that of coal. Young’s modulus is related closely to the brittleness property.$^{70,71,74,75}$ In general, the higher the Young modulus, the stronger the brittleness property and the less the energy loss during fracturing, which is conducive to generate a more complex fracture network and produces better fracturing consequences. Moreover, the effect of the brittleness property on hydrofracture consequences has been confirmed by fracture tracing technology and microseismic monitoring technology.$^{75}$ Meanwhile, the mechanical properties of tonstein intercalation are better and proppant embedding becomes more difficult.
compared with coal, which reduces the risk on the closure of induced fracture and maintains fracture conductivity.

Compared with coal, tonstein intercalation features with poor methane adsorption, resulting in a methane concentration gradient between tonstein intercalation and pure coal. Driven by this methane concentration gradient, methane becomes easier to migrate to wellhole relative to the pure coal without this kind of driving force, which is conducive to the high gas production rate of CBM wells.

To sum up, tonstein intercalation in a coal reservoir is conducive to CBM development. This is attributed to three reasons: (1) the gas concentration gradient between tonstein intercalation and coal, (2) superior brittleness of tonstein intercalation contributing to the generation of a complex fracture network, and (3) great strength of tonstein intercalation preventing the closure of induced fractures.

3.2.4. Coal Deformation. As coal deformation increases, Young’s modulus, which can be used to evaluate the brittleness, decreases.12 The higher the brittleness of coal, on the one hand, the more easier the formation of artificially induced fractures and, on the other hand, the lower the permeability damage caused by stress sensitivity of the coal matrix at the initial extraction stage.36 Concerning intact and cataclastic coals, due to relatively higher Young’s modulus, artificial fracture networks induced by hydraulic fracturing can be formed as effective migration pathways. Moreover, the proppant-supported induced fractures ensure the opening of induced fractures so that permeability and flow conductivity improve after hydraulic fracturing. However, for granulated and mylonitized coals, the fracture network is difficult, even impossible, to form. By comparing the coal core plugs, hydrofracture operation curves, and induced fracture monitoring data of a number of CBM wells in the Changzhi block, it is found that the percentage of the granulated–mylonitized coal thickness is reversely proportional to the fracture extension length.76 In addition, due to poor mechanical properties, the pumped proppants are almost embedded into coal and effective migration pathways cannot be maintained.

As shown in Figure 19, what stands out is the shape of the pump pressure curve. According to the alternation of the pumping pressure curve, it can be divided into three types: fluctuating-rising type, stable type, and descending type. As a matter of fact, the hydrofracture operation curve relates closely to coal deformation. Hu et al.76 carried out experiments on fracture initiation and propagation using the two coal samples collected from an underground coal mine. The obvious difference between two coal samples is the distribution characteristics of natural fractures. According to their results, initial coal with undeveloped natural fractures is prone to generate an induced fracture with a dominant direction, and its curve shape is the stable type. However, deformed coal with developed natural fracture tends to form a fracture network that consists of many crisscross-induced fractures because induced fractures show multiple steering, initiating, and propagating based on the existence of natural fractures, and its curve shape is the fluctuating-rising type. Concerning granulated–mylonitized coal, in most cases, its curve shape belongs to the descending type. According to core plugs from CBM wells, the aforementioned phenomena have been verified. Indeed, all core plugs from the F9 CBM well belong to initial coal, initial cataclastic coal from the F10 CBM well,
and granulated–mylonitized coal from the Z1 CBM well (Figure 19).

According to the shape of the hydrofracture operation curve, hydrofracture consequences can be estimated. Relative to the descending type of the Z1 well, the hydrofracture consequences of the fluctuating-rising type of the F10 well and stable type of the F9 well are greater. For instance, the average gas production rate of the Z1 well is only 682 m³/day, but those of the F10 well and F9 well are up to 1174 and 1106 m³/day, respectively.

Excitingly, the Shanxi Coalbed Methane Exploration and Development Branch of PetroChina Company takes an innovative step (roof fracturing technology) to solve the CBM development challenge from granulated–mylonitized coal. It is via connecting the main fractures induced in the roof due to hydrofracture operation and natural fractures in the coal reservoir that these coal reservoirs with strong deformation can be mined. For the HL-X CBM well in the Changzhi block, it is dominated by cataclastic coal and granulated coal, and the gas production rate is only 200 m³/d after the coal seam is hydrofractured but is up to 900 m³/d using roof fracturing technology.76

3.2.5. In Situ Stress. In situ stresses, including horizontal and vertical stresses, increase with increasing buried depth (Figure 20). Within the buried depth range, the maximum horizontal principal stress is the greatest; therefore, its magnitude and direction govern the initiation and propagation of induced fractures. Compared with the vertical stress, higher correlations between the maximum principal stress, fracturing pressure, and fracture extension length are observed in Figures 21 and 22. Furthermore, the extension direction of induced fractures is consistent with the direction of the maximum horizontal principal stress based on microseismic fracture monitoring data. In fact, the increase of in-situ stresses makes it hard to initiate the coal reservoir during hydrofracture operation. As shown in Figure 22, the fracture extension length correlates negatively with the maximum principal stress and vertical stress.

Diao et al.75 adopted shale samples to carry out failure experiments at various confining pressures to uncover the evolution of induced fractures under in situ stresses. According to their results, with increasing confining pressure, the number and length of microfractures induced reduce gradually, indicating that the growth of confining pressure restricts the propagation of microfractures and causes the transformation from brittle to ductile failure. Relative to shale, coal possesses weaker brittleness, implying fewer microfractures and shorter extension for coal at the same confining pressure. Indeed, we find that the fracture extension length correlates negatively with in situ stresses based on the data from microseismic fracture monitoring technology (Figure 22). Hu et al.76 conducted hydrofracture experiments to discuss the effect of various in situ stresses on artificially induced fractures. Their results show that when the vertical stress is greater, the single fracture with the horizontal direction is dominated. When the maximum horizontal principal stress is more than the vertical stress, the fracture shape transforms from simple to complex. As the in situ stresses increase, some unfavorable factors for CBM development such as a high fracturing pressure, a tiny amount of induced fractures, a short extension length, and a simple fracture shape all restrict the consequences of hydrofracture operation, eventually giving rise to the poor gas production performance. This coincides with the negative correlation between the maximum horizontal principal stress and gas production rate of CBM wells in Fanzhuang and Zhengzhuang blocks (Figure 23). Fortunately, the Shanxi Coalbed Methane Exploration and Development Branch of PetroChina Company uses induced composite fracturing technology to overcome this problem. Namely, using hydro-blasting circulation flushing alters original in situ stresses and forms multiple induced fractures before hydrofracture operation.
operation. For the ZS-X CBM well in Zhengzhuang block, the gas production rate is only 200 m$^3$/d using conventional hydrofracture technology and reaches 1400 m$^3$/d after stimulation in the form of hydroblasting circulation flushing.$^7$ In summary, hydrofracture stimulation plays a much important role in CBM development.

3.3. Differences in Key Influencing Factors among the Three CBM Blocks Selected. The differences in the physical properties of coal reservoir, tectonic settings, buried depth, and hydrofracture consequences lead jointly to various gas production performances of three different CBM blocks.

With increasing buried depth, both in situ stresses and gas contents increase (Figures 6 and 20), while permeability decreases (Figure 9). In general, high in situ stresses and low permeability result in poor gas production performance (Figures 13 and 23). The north of the Fanzhuang block and the southwest of the Zhengzhuang block have high gas production rates due to shallower buried depths. On the contrary, the north of the Zhengzhuang block has poor gas production performance due to the large buried depth. Intense tectonic movements produce granulated–mylonitized coal, where CBM development is facing enormous challenges, although roof fracturing technology has made some achievements. The southeast of the Zhengzhuang block and whole Changzhi block have poor gas production rates due to the development of granulated–mylonitized coal.

In addition, hydrofracture technology is not ignored for CBM development. Good stimulation consequences are the
premise of achieving excellent production performance. Once caprock integrity is destroyed, subsequently poor production performance occurs even though the coal reservoir involves classy physical properties, such as F2 and F6 CBM wells in the Fanzhuang block. Therefore, the optimization of hydrofracture parameters and associated technology should be taken into consideration to ensure caprock integrity.

4. CONCLUSIONS

(1) According to long-term practice productivity curves, two types can be identified: unimodal model and bimodal model. The unimodal model corresponds to the declining pump pressure curves, and the bimodal model is attributed to fluctuating-rising and stable pump pressure curves. The unimodal model relates closely to poor gas production performance because the sealing of caprock is destroyed. Therefore, it is deduced that the first-peak gas production rate is dominated by hydrofracture stimulation.

(2) Gas content is of basic achieving great production performance but is not a major factor influencing the gas production rate. Gas saturation/critical-reservoir pressure ratio and permeability are proportional positively to the gas production rate. Coal deformation affects the gas production rate due to the differences in the pore-fracture system.

(3) Engineering factors affect the gas production rate via four aspects: the effect of hydrofracture operations on caprock integrity, the effect of fluids pumped on the pore-fracture system, the initiation and propagation of artificially induced fractures, and the performances of proppants pumped.

5. OVERVIEW OF THE QINSHUI BASIN

5.1. Geological Background. The Qinshui Basin, located in southeast Shanxi Province, China, is an intracratonic fault basin. Figure 24 shows the geological structure configurations and the isoline roof elevation of the No. 3 coal reservoir of the three CBM blocks in the Qinshui Basin, China. The west and east margins of the Qinshui Basin are adjacent to Lviang and Taihang Mountain Uplifts, respectively; its south and north edges are bounded on the Wutiao and Zhongtiaoshan Mountain Uplifts, respectively. Due to the superposition of multistage tectonic movements such as Yanshan and Himalayan orogenies, the Qinshui Basin evolves into a large-scale compound syncline structure with NNE orientation nowadays.75

Fanzhuang and Zhengzhuang blocks (Figure 24a) are major gas-producing areas in the Qinshui Basin. The Sitou fault is the boundary of Fanzhuang and Zhengzhuang blocks. Structurally, the Fanzhuang block is distributed in the Jincheng slope zone of the southern Qinshui Basin. In this block, the NNE-oriented local syncline structure is primary, and secondary folds are developed. Specifically, the west and north are mainly distributed with compact folds that feature with the spatial distribution of anticline—syncline intervals; the west has relatively simpler, wide-gentle short-axis folds. The faulted structures are relatively developed, mainly concentrating on the west.78 The Zhengzhuang block is located on the “horseshoe” slope zone in the south of the Qinshui Basin. The faults in this block are extremely developed, among which the Sitou and Houchengyao faults are distributed in east and southeast areas, featured with great fault throw and long extension length, respectively. Due to multistage tectonic extrusion, the folds are usually wide-gentle with the major orientation of near SN and NNE.76 The Changzhi block (Figure 24b), as a successive block for CBM development nowadays, is in a transition area between the east margin of Qinshui Basin synclinorium and the west edge of Taihangshan anticlinorium.75 It belongs to a west-dipping monocline, whose orientation is NNE-NEE with an about 4° dip angle. Due to tectonic movements, major transtensional faults that are oriented at NE and NNE and minor crumples that consist of gentle folds with the orientation of NE and closed folds with the orientation of NNE and NNW develop widely in the southeast Changzhi block.80

The strata in three CBM blocks are, from the bottom to the top, the Shangmajiagou and Fengfeng formations in middle Ordovician; the Benxi formation in upper Carboniferous; the Taiyuan formation in upper Carboniferous; Shanxi, Xiaohixiezi, Shangshihiezi, and Shiqianfeng formations in Permian; and the Lijuagou formation in lower Triassic.79–81 Based on coal core observation and logging interpretation, Shanxi formation is the main coal-bearing strata and includes 4 coal seams. Among them, the No. 3 coal seam is the major target for CBM exploration and development due to the wide distribution and great thickness.

5.2. Physical Characteristics of the No. 3 Coal Reservoir. In this work, 74 CBM wells, consisting of 13, 30, and 31 CBM wells in the Fanzhuang, Zhengzhuang, and Changzhi blocks, respectively, are selected. Based on the macroscopic and microscopic observations of core plugs and the experimental results of physical properties, the physical and petrographic characteristics of the No. 3 coal seam are summarized in Table 1. The gas content, proximate analysis, organic maceral, vitrinite reflectance, and fracture observation are determined according to China National Standards GB/T 19599-2008, GB/T 212-2008, GB/T 8899-1998, GB/T 6948-2008, and MT/T 968-2005, respectively.

Figure 25 shows the photograph of coal core plugs with different degrees of deformation obtained during drilling operations; their features are described in detail in a previous publication.82 According to the macroscopic observation of core plugs, the Fanzhuang block is dominated by intact coal (Figure 25a) and cataclastic coal (Figure 25b). Concerning the Zhengzhuang block, granulated coal (Figure 25c) and...
mylonitized coal (Figure 25d) are well developed near Sitou and Houchengxiao faults and intact coal (Figure 25a) and cataclastic coal (Figure 25b) are dominated in the rest area of this block. For the Changzhi block, granulated coal (Figure 25c) and mylonitized coal (Figure 25d) are well developed except at the center of this block, where faults and folds are relatively undeveloped.

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Notes
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