Analysis of productivity differences in vertical coalbed methane wells in the Shizhuangnan Block, Southern Qinshui Basin, and their influencing factors

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Abstract
Coalbed methane wells in the Shizhuangnan Block exhibit significant productivity differences. The reasons were determined based on the impact analysis of geological factors and drainage strategies on production capacity at 82 wells. Grey relational analysis was further utilized to quantitatively analyze the correlation degree of geological parameters to production characteristics. It is found that the main reason for wells with high water production is the ingress of external water, i.e. connecting adjacent aquifer by natural faults or artificial fractures. And aquifer characteristics, especially thickness of aquifer has the greatest influence on the water production, followed by pore connectivity, porosity, and shale content. For the wells that have not been affected by external water, the gas productivity differences are mainly affected by reservoir conditions and drainage strategies. Finally, an analytical process was proposed to provide theoretical support for rational production of coalbed methane wells.

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Introduction

There is currently high demand for natural gas in China; the gap between supply and demand reached 60 billion cubic meters in 2016 (Hou et al., 2018). The development of coalbed methane (CBM) gas is one of the most important measures that have been put forward to alleviate the gas shortage (Guo et al., 2019; Liu et al., 2019; Wu et al., 2019; Yan et al., 2020). As the largest CBM-producing basin in China, the Qinshui Basin is rich about $3.28 \times 10^{12} \text{ m}^3$ CBM resources in place (Su et al., 2005), and the southern of the basin (SQB) is considered favorable for CBM development. However, most of wells have low gas production.

To reach the true production potential, the problems for low gas-yield CBM wells need to be analyzed and overcome. Previous work has shown that reservoir characteristics, structural properties, and hydrogeological conditions have important influences on gas accumulation and preservation, and have practical significance for CBM exploration and development (Cai et al., 2011; Meng et al., 2014; Wang et al., 2013; Yang et al., 2017; Yao et al., 2008). Additionally, some studies attempt to analyze the main factors affecting the low production of CBM by statistical methods (Akhondzadeh et al., 2018; Aslan, 2013; Zhao et al., 2015; Zou et al., 2018). However, these studies of geological factors either have taken insufficient account of differences in the productivity characteristics of production wells, or mainly qualitative and lack quantitative or semi-quantitative analysis. Generally, accurate evaluation of gas content, and then optimization of favorable areas of high gas content is very important for CBM wells production (Liu et al., 2014; Lv et al., 2012). The initial gas content of coal reservoir is the basis of high gas well production and cannot be improved by human factors. Another key factor controlling the high production of CBM wells is the sufficiency of the reservoir depressurization, which can be improved by human factors. Many researches have done relevant analysis in terms of engineering and drainage factors (Jiang et al., 2017; Li et al., 2014; Liu et al., 2018b; Meng et al., 2011; Zhang et al., 2017, 2018). For the drainage strategy, most scholars recommend that it should stabilize the bottom-hole flowing pressure (BHFP) when CBM wells begin to produce gas (Liu et al., 2013, 2018a). But a large number of high gas-yield wells do not adopt this drainage strategy, instead regulating the BHFP so that it continues to drop rapidly after the start of production. Crucially, permeability and gas saturation are the most vital factors in determining the reservoir depressurization (Moore, 2012). Unfortunately, the drainage strategies are not adjusted based on the geological conditions in the actual production process, which ultimately result in the low gas production of a large number of CBM wells. Therefore, we should not only focus on the gas content, but also pay more attention to how to combine geological, engineering, and drainage strategy factors to fully depressurize the coal reservoir and enhance the recovery in the production stage.

Whether the reservoir can be fully depressurized depends on external factor and internal factor. External factor is the influence of external water which can inhibit the depressurization, so the invasion of external water should be avoided first in the production process.
The internal factor is mainly the permeability of the reservoir itself. To analyze productivity differences and their influence factors, in this manuscript, the influence of external water is analyzed from the aspects of hydrochemistry, lithological evaluation, fracture propagation direction, and water production characteristics. Furthermore, the internal factors without the influence of external factors, especially the geological conditions and the drainage strategy, were considered, and suggestions were further made for the regulation of the drainage strategy. Finally, based on the research conclusions, an analytical process was proposed to provide theoretical support for rational production of CBM wells.

This study is based on the exploration and development data of Shizhuangnan Block (SZB) in the SQB. And the wells used in this study are classified into three types: high-yield wells that produced CBM more than 1000 m$^3$/d, moderate-yield wells at 500–1000 m$^3$/d, and at low-yield wells less than 500 m$^3$/d.

**Geological setting**

The SZB is located in the SQB, Shanxi Province (Figure 1(a) and (b)). The field is structurally simple, being composed of an NNE-striking monocline that dips 3–13° toward the west. The principal coal-bearing strata are the upper Carboniferous Taiyuan Formation (#15) and the lower Permian Shanxi Formation (#3). Production at the mine-field is currently mainly from coal seam #3, which is dominantly anthracite; its coal vitrinite reflectance ($R_m^{\text{max}}$) ranges from 2.92 to 3.02% (Zhang et al., 2015). The thickness of this coal seam is stable, with an average of 6.35 m. The gas content of the coal is between 7 and 21 m$^3$/t (Yan et al., 2019). In addition, there are five aquifers in this block, and P$_1$x-P$_1$y aquifer and C$_3$t aquifer have significant influences on CBM development (Figure 2).

There are more than 10 secondary steep-angle normal faults in the north of the study area near the Sitou Faults, which cut the coal measure strata and limit the production of CBM (Tao et al., 2014; Li et al., 2019). Since few reverse faults develop in the block, it is unnecessary to analyze the role of reverse faults in detail. While in the central part of the block, the CBM wells are far from the faults, but the levels of gas and water production of these wells differ significantly, and the distribution of wells with different productivity characteristics is inhomogeneous (Figure 1(c)). This indicates that the productivity differences of the CBM wells have complex causes that require further analysis.

**Data and methods**

**Target wells selection**

Eighty-two wells were employed as the examples in the SZB for analysis in detail. All of these wells are vertical wells producing #3 coal layer and unaffected by the potential collapse column. They are mainly distributed in two areas. Eight wells are in the northern faulted zone and have been in production for more than three years. The minimum and maximum average daily water production is 2.9 and 13 m$^3$/d, respectively. Among them, except two low production wells (product gas 94 and 240 m$^3$/d, respectively), the other wells do not produce gas after long-term drainage (Figure 3). Other 74 wells are in the central region without faults developed. Their production time ranges between 1956 and 2663 days with an average of 2320 days (Figure 4(a)), indicating that the development has entered the stable stage. Furthermore, in order to reduce the impact of production time, analysis of their
productivity characteristics mainly focuses on the average daily gas and water production. These wells contain 37 low gas-yield wells with an average gas production of 239 m$^3$/d, 17 moderate gas-yield wells with an average gas production of 702 m$^3$/d, and 20 high gas-yield wells with an average gas production of 1368 m$^3$/d. Generally, there is a significant negative correlation between average daily gas production and water production (Figure 4(b)). Average daily water of most high gas-yield wells is less than 1.2 m$^3$/d. However, most CBM wells with an average daily water production of more than 2 m$^3$/d are low gas-yield wells.

**Water samples**

Hydrochemical analysis was used to identify the source of produced water, which is helpful to analyze the productivity influences of CBM wells, so water samples from eight wells near the faults were collected for testing. Before sample collection, the containers were flushed three times with sample water. Thereafter, the containers were filled to the brim, carefully closed, and then sealed using paraffin wax. After the collection was completed, the samples were sent to the First Exploration Bureau Testing Center of China National Coal Geology Administration within 48 h for full analysis according to the standard “General Provisions...
of Coal Mine Water Quality Analysis (MT/T 894-2000)” (Zhang et al., 2016). Finally, the cations $K^+ + Na^+, Mg^{2+}, Ca^{2+}$ and the anions $HCO_3^- + CO_3^{2-}, SO_4^{2-}, Cl^-$ were tested.

**Evaluation of artificial fractures**

Because the fracturing processes of these wells are similar and lack of fracture monitoring data, accurate fracture parameters, like fracture length and permeability, are hardly obtained.

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### Figure 2. Delineation of stratigraphic and hydrostratigraphic characteristics in the SZB.

| Era/System period | Formation | Hydrostratigraphic |
|-------------------|-----------|--------------------|
| Cenozoic          | Quaternary (Q) | Aquifer, with lower water abundance and permeability |
| Mesozoic          | Shiqianfeng | Aquifer           |
|                   | Shangshihezi |                   |
|                   | Xiashihezi  |                   |
| Permian (P)       | Shanxi 39.7~67.8m | P1-P15 aquifer, with lower water abundance and permeability |
| Paleozoic         | Taiyuan 93.9~139.7m | Aquifer |
|                   | Benxi 9.3~12.5m | Aquifer |
| Carboniferous (C) | Fengfeng 50~100m | Aquifer, with higher water abundance and permeability |
| Ordovician        | Limestone | Absent due to erosion |
|                   | Sandstone |                   |
|                   | Shale     |                   |
|                   | Coal      |                   |
In this paper, we only analyzed the influence of fracture propagation direction on productivity according to the in-situ stress conditions. In-situ stress has two major orientations (vertical and horizontal). The direction of least principal stress is an important factor for predicting the orientation of hydraulic fracture planes because fractures always propagate perpendicular to the orientation of the least principal stress (Blunschi et al., 2017). If the overburden stress (vertical principal stress) is
less than stress in all other directions, fractures will propagate horizontally, and the surrounding rock will not generally be easily penetrated; on the contrary, if the least horizontal principal stress is the least, fractures will propagate vertically, and the properties of the seal layer must be taken into consideration. Generally, in-situ stress can be calculated from fracture generation data and logging data as follows (Jaeger and Cook, 1979)

\[ \sigma_{h1} = P_c \]  
\[ \sigma_z = \int_0^z \rho(z) g dz \]

where \( \sigma_{h1} \) is the least horizontal principal stress (MPa); \( \sigma_z \) is the overburden stress (MPa); \( g \) is the acceleration due to gravity (m/s\(^2\)); \( \rho(z) \) is the formation density (kg/m\(^3\)), which can be obtained from the density logging data; \( z \) is the burial depth (m); and \( P_c \) is the closure pressure, which can be obtained from the fracture construction data (Zoback et al., 2003).

**Lithological evaluation**

Whether fractures can penetrate the aquifer is not only dependent on the direction of fracture propagation but also on the sealing properties of the surrounding rock. Formation lithology is usually distinguished by geophysical logging, which can provide data on the physical and chemical properties of formations and fluids (Fu et al., 2009). Because clay particles have a strong adsorption capacity for radioactive elements, Peng et al. (2017) used logging data on natural radiation from CBM wells in the SZB to establish a logging model, which is used to calculate the shale content of a formation and further analyze the sealing properties of the direct roof and floor

\[ V_{sh} = \frac{2I_{GCUR}I_{GR} - 1}{2I_{GCUR} - 1} \]  
\[ I_{GR} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}} \]

where \( V_{sh} \) is the shale content (%); \( I_{GCUR} \) is the Hilchie index, related to the geological age of the strata, \( I_{GCUR} = 2 \) in this block; and \( I_{GR} \) is the natural gamma relative value (%). \( GR, GR_{min}, \) and \( GR_{max} \) are \( GR \) value of target strata, pure sandstone strata, and pure mudstone strata, respectively, API. In general, the natural gamma amplitude of mudstone is 75–150 API, with an average of 100 API. The natural gamma amplitude of pure sandstone is 20–30 API (Wei and Zou, 2005).

**Analytical process**

There are noticeable differences in the geological characteristics of the coal reservoir in this block that should be further studied. Based on the actual development situation, the production modes can be divided into four types (Figure 5). First, natural faults are considered preferentially, as normal faults play crucial roles in the CBM preservation and
depressurization (Figure 5(a)). Production wells near normal faults have low gas production potential, so CBM wells should be drilled far away from fault zones. Second, for CBM wells that are not affected by faults, the coupling relationship between the sealing ability of the surrounding rock and artificial fractures should be analyzed. Specifically, if the direct roof and floor of the coal seam are poorly sealed and stress state promotes vertical fracture propagation, the fractures will penetrate the aquifer, resulting in high water production and low gas production (Figure 5(b)). Conversely, in the case of the surrounding rock having good sealing ability or artificial fractures being horizontal, external water will not influence the production, and the drainage strategy should be adjusted on the basis of the reservoir properties (Figure 5(c) and (d)).

Finally, an analytical process was proposed to specifically explore the differences in productivity between each mode and the factors causing these differences. It is worth noting that it is crucial to evaluate “sweet point” of CBM resources before development,
because the gas content plays a direct role in the gas yield. However, for the developed blocks, the key is efficient depressurization and recovery enhancement. Thus, this process mainly focuses on the coupling relationship between reservoir properties and human factors, and finally solves the problem of low gas production from CBM wells (Figure 6).

**Results and discussion**

*Productivity differences with the influence of external water*

The previous study of logging data has shown that the coal seam in the SZB has low water content. The water saturation is generally less than 2%. In addition, continuous hydrochemical analysis shows that the water chemistry differs at wells, indicating that some high water-yield CBM wells produce water that incorporates external water as well as water from the coal seam (Zhang and Qin, 2018). Therefore, the impact of external water on the productivity of CBM wells should not be negligible.

*Natural faults penetrating the aquifer.* Fault structures have very important impacts on production from wells in the study area: on the one hand, faults destroy the coal reservoir and cause the loss of CBM, thus reducing the gas content of the coal seam (Colmenares and Zoback, 2007); on the other hand, normal faults form a natural channel which connects the surrounding rock and the coal seam, and the free water in the surrounding rock aquifer enters the coal seam easily through these normal faults, hindering the expansion of pressure funnel drop and the effective production of CBM (Figure 5(a)).

The ionic content of water samples from the eight CBM wells near the faults was compared with the ionic content of water from the aquifers in a Piper diagram (Table 1 and
The chemical characteristics of water produced in wells near the faults are generally similar to those of the roof aquifer, but the chemical characteristics of two wells are intermediate between those of the roof and floor aquifer, indicating that the faults not only penetrate the aquifer in the indirect roof but also that in the indirect floor.

The gas content of the reservoirs of the sampled wells is calculated by the prediction model that Peng et al. (2017) established based on the combination of isothermal adsorption experiments and logging data from the SZB. The predicted initial gas content of these eight wells ranges from 7.48 to 15.16 m$^3$/t with an average of 11.06 m$^3$/t (Figure 3), indicating that coal storage conditions are poor near faults, and the CBM is easily dispersed.

In summary, the presence of fault structures is an important factor affecting the production capacity of the CBM wells in the northern part of the SZB. The natural faults penetrate aquifers, causing most of the wells distributed near these structures to exhibit high water production and low or no gas production.

**Artificial fractures penetrating the aquifer.** Before starting production, artificial fracturing is required to improve reservoir permeability due to the low initial reservoir permeability in the SZB. Equations (1) and (2) were used to calculate the overburden stress (the vertical principal stress) and the least horizontal principal stress, and a relationship diagram was
drawn to compare the two. The direction of fractures was further calculated (Figure 8). What is more, the rocks surrounding a coal seam can be divided into the direct/indirect roof and floor. The indirect roof and floor are sandstone aquifers, while the direct roof and floor of coal seam #3 are impermeable stratum (mudstones or shales), which have sealing ability (Equations (3) and (4)). It should be worth noting that for vertical artificial fractures, penetrating either sealing layer can lead to the ingress of external water (Figure 5(b)), so the relationship between the thickness of the thinner of the two sealing layers and the average water production was analyzed (Figure 9).
It can be seen from Figure 9 that a sealing-layer thickness of 3 m constitutes a threshold, that is when the thickness of the sealing layer is greater than 3 m, the average daily water production is less than 2 m$^3$/d, while when the thickness of the sealing layer is less than 3 m, the average daily water production is more than 2 m$^3$/d. Furthermore, since the production time of the target wells is greater than 2000 days, the cumulative water production is greater than 4000 m$^3$, indicating that these wells are affected by external water (Jiang et al., 2016).

The correlation between the properties of the aquifer and the water production was further analyzed. The properties of aquifer can be reflected by various parameters, such as thickness, porosity, pore connectivity, and shale content of aquifer (Li, 2016). First, thickness of aquifer reflects the magnitude of water storage space: the thicker the aquifer, the greater the storage space. Second, the porosity can be used to characterize the pore space and also reflects the magnitude of water storage space. Third, because saline formation water is a good conductive medium and filled in pore, and excellent pore connectivity will significantly reduce the resistivity of the sandstone aquifer, the resistivity can provide a good indication of the pore connectivity of the sandstone layer. Fourth, because sandstone strata with low shale content are able to provide more external water to the coal seam, high average daily water production is proportional to low shale content in the indirect roof (Peng et al., 2017). The relationships between the various factors and average water production are plotted in Figure 10.

![Figure 10. Scatter plots of average daily water production and various factors of the sandstone aquifer. (a) Porosity, (b) resistivity value, (c) shale content, and (d) thickness.](image-url)
Grey relational analysis is used to quantitatively analyze the correlation between the geological parameters of the aquifer and the average daily water production of the CBM wells affected by the aquifer. Grey relational analysis is an excellent tool to select the factors with the strongest influences from among numerous quantifiable parameters and to provide a quantitative evaluation of their degree of effect, and it has been utilized for CBM productivity analysis previously (Tao et al., 2014; Zhao et al., 2015; Zou et al., 2018). The magnitude of the relationship can be characterized by the correlation degree.

The results show that aquifer thickness has the greatest influence on the average daily water production, followed by pore connectivity and the porosity of the aquifer, and the shale content of the aquifer has the least influence on the average daily water production (Figure 10 and Table 2).

### Table 2. The correlation degree between water production with aquifer properties.

| Factors         | Correlation | Rank |
|-----------------|-------------|------|
| Thickness       | 0.8302      | 1    |
| Pore connectivity| 0.776       | 2    |
| Porosity        | 0.6887      | 3    |
| Shale content   | 0.5907      | 4    |

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### Productivity differences without the influence of external water

It should be noted that there are a large number of low gas-yield wells with water production less than 1.2 m³/d (Figure 4(b)), indicating that low gas production of these wells is not caused by the ingress of external water (Figure 5(c) and (d)). Therefore, the influencing factors were further analyzed.

**Geological factors.** The heterogeneity of coal reservoir is a key factor leading to the differences in CBM production. In this study, geological factors were mainly analyzed from the aspects of fracture propagation direction, gas content, coal reservoir permeability, reservoir pressure, critical desorption pressure, burial depth, and thickness.
The fracture propagation direction of low water-yield wells is calculated by equations (1) and (2). It is found that the artificial fractures of most high gas-yield wells are vertical while those of most low gas-yield wells are horizontal (Figure 11). The reason is that the reservoir pressure gradually reduces with the CBM development, and the effective overburden stress gradually increases. Permeability of horizontal fractures is easier to decrease than that of vertical fractures, which ultimately limits the flow of fluid in the coal seam and expansion of the pressure funnel drop (Huang et al., 2019; Wang and Zhang, 2018).

Gas content reflects the gas storage capacity of the reservoir, which directly affects the gas production of CBM wells. The gas content of these wells ranges 9–21 m³/t. In addition, there is a positive correlation between gas content and average daily gas production of the CBM wells (Figure 12(a)).

Coal reservoir permeability is a key property controlling the ability of fluid to migrate, and it is one of the reservoir parameters that most strongly control the extraction of CBM (Durucan and Edwards, 1986; Han et al., 2010; Pan and Connell, 2012). Li et al. (2011) established a reservoir permeability calculation model on the basis of logging data, which indicates that the original coal reservoir permeability is generally less than 1 mD in the SZB. Permeability of target wells in the central area ranges from 0.05 to 0.8 mD, and there is a significant positive correlation between reservoir permeability and average daily gas production (Figure 12(b)).

Reservoir pressure and the critical reservoir ratio (the ratio of the critical desorption pressure to the reservoir pressure) are the key factors that control the gas content of CBM wells. High reservoir pressure indicates good storage conditions for CBM. Similarly, a high critical reservoir ratio will not only tend to shorten the gas breakthrough time, but also expand the desorption range and improve gas production (Figure 12(d) and (f)) (Tao et al., 2012; Walsh, 1981; Yao et al., 2009).

The burial depth of the coal seam mainly affects the vertical principal stress on the reservoir, and further affects the fracture propagation direction. However, the direction of fracture propagation is not only affected by the vertical stress, but also by the horizontal stress. Therefore, buried depth has little effect on the productivity differences of CBM wells (Figure 12(c)).

Coal seam thickness also influences the magnitude of CBM resources. A thicker coal seam constitutes a larger reservoir volume and richer resources. The thickness in this area ranges from 5.5 to 6.5 m with little heterogeneity (Figure 12(e)).
Grey relational analysis is used to study the correlation between geological factors and average gas production in low water production wells (Table 3). Reservoir permeability is found to be the crucial factor affecting the gas production of these wells, while the burial depth and reservoir thickness have the lowest impact on gas production.

**Engineering factors.** Reservoir conditions are the basis for CBM production, but the drainage strategy adopted during development is also a key factor. At present, the development of

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**Figure 12.** Scatter plots of the main factors affecting productivity differences. (a) CBM content, (b) original permeability, (c) burial depth, (d) coal reservoir, (e) coal seam thickness, and (f) critical reservoir ratio. CBM: coalbed methane.
CBM wells is usually carried out by regulating the BHFP to reduce the reservoir pressure. In this study, the drainage strategies adopted in the high and low gas-yield production wells in our samples were compared. High gas-yield wells can be further divided into two types based on the time of wells reaching high gas yield: those that reach high gas yield quickly and then being stable, and those that have low initial gas yield and gradually reach high gas yield in the later stage.

The production characteristics of these three types of wells are significantly different. The first type of high gas-yield wells reach high production in about 250 days (Figure 13(a)), and the second type reach high production in about 800 days (Figure 13(b)), which are similar to the corresponding average time for reaching high production (Table 4). Although the time for these wells to reach high production is significantly different, there are similar production rules, that is when the BHFP drops to 1 MPa and the daily water production reduces to 1 m³/d, the gas production can reach a high yield. On the contrary, for low gas-yield wells, drop rate of the BHFP is much faster than water production in the early stage (Figure 13(c)).

In the aspect of dynamic characteristics of production, differences are also obvious. The drainage radius of the two types of high gas-yield wells increases rapidly in the early stage and then tends to be stable in the later stage, while that of the low gas-yield wells is relatively slow as a whole (Figure 14(b)). Furthermore, the reservoir pressure of the first type of high gas-yield wells decreases rapidly in the whole production stage (1.26 kPa/d), and that of the low gas-yield well decreases slowly (0.45 kPa/d). However, the reservoir pressure of the second type of high gas-yield wells tends to be stable in the stable stage of BHFP, and then decreases rapidly after BHFP drops (Figure 14(a)). More importantly, the Langmuir curve shows that for all three types of wells, when the reservoir pressure is greater than 1 MPa, only less than one-third of CBM can be desorbed. In other words, in order to make CBM well reach its true potential, the reservoir pressure needs to be fully dropped to below 1 MPa (Figure 14(c)).

The prerequisite of sufficient depressurization of reservoir is to study the percolation ability of reservoir. Therefore, the relationship between reservoir permeability and average daily gas production was further analyzed due to the highest correlation degree between reservoir permeability and productivity differences in low water production wells. The results show that reservoir permeability of low gas-yield wells is less than 0.3 mD, while that of high gas-yield wells that reach high yield quickly is mostly greater than 0.3 mD. However, for high gas-yield wells that reach high yield slowly, reservoir permeability is

| Factors                  | Correlation | Rank |
|--------------------------|-------------|------|
| Permeability             | 0.8152      | 1    |
| CBM content              | 0.7836      | 2    |
| Critical reservoir ratio | 0.7383      | 3    |
| Coal reservoir pressure  | 0.7382      | 4    |
| Burial depth             | 0.7267      | 5    |
| Thickness                | 0.7250      | 6    |

CBM: coalbed methane.
Figure 13. Production characteristics of CBM wells with differing productivity. Daily water production, daily water production, BHFP, drainage radius, and reservoir pressure are the average values of the corresponding parameters for all production wells of corresponding type. (a) Characteristic of productivity dynamic curves of high gas-yield wells that reach high yield quickly (nine wells), (b) characteristic of productivity dynamic curves of high gas-yield wells that reach high yield slowly (nine wells), and (c) characteristic of productivity dynamic curves of low gas-yield wells with low water production (nine wells).
discrete: for some, it is less than 0.3 mD and fractures are vertical, while for others it is more than 0.5 mD and fractures are horizontal in this condition (Figure 15). It shows that the sufficient depressurization of the reservoir depends on the reservoir fluid supply capacity, which is closely related to the permeability of the reservoir and the direction of fracture.

In summary, a reasonable drainage strategy is conducive to high production from CBM well. For high gas-yield wells, the pressure perturbation radius expands to outward gradually by controlling the BHFP in the early stage until the reservoir fluid supply capacity decreases and the pressure perturbation radius reaches the well-controlled boundary $r_c$. Furthermore, when the reservoir pressure drops below the critical desorption pressure, CBM begins to be desorbed; the gas desorption area is less extensive than the pressure perturbation area (Li et al., 2018) (Figure 16). Thereafter, the BHFP is kept stable at a

| Type of wells                                      | Permeability of coal reservoir (mD) | Average daily water production (m³/d) | Average daily gas production (m³/d) | Reach high production time (d) |
|---------------------------------------------------|-------------------------------------|--------------------------------------|------------------------------------|--------------------------------|
| High gas-yield wells that reach high yield quickly (nine wells) | T79 | 0.305 | 0.325 | 1054 | 210 |
|                                                   | Z54 | 0.348 | 0.336 | 1125 | 320 |
|                                                   | T21 | 0.470 | 0.387 | 1151 | 40  |
|                                                   | Z68 | 0.435 | 0.397 | 1538 | 360 |
|                                                   | Z71 | 0.528 | 0.456 | 2342 | 323 |
|                                                   | T80 | 0.371 | 0.539 | 1481 | 245 |
|                                                   | Z59 | 0.403 | 0.543 | 1919 | 192 |
|                                                   | T88 | 0.420 | 0.664 | 1249 | 202 |
|                                                   | Z46 | 0.353 | 0.933 | 1282 | 220 |
| Average                                          |     | 0.404 | 0.509 | 1462 | 235 |
| High gas-yield wells that reach high yield slowly (nine wells) | T22 | 0.762 | 0.420 | 1467 | 850 |
|                                                   | T93 | 0.260 | 0.518 | 1079 | 860 |
|                                                   | Z42 | 0.608 | 0.573 | 1456 | 1058 |
|                                                   | T1  | 0.135 | 0.668 | 1109 | 616 |
|                                                   | T24 | 0.550 | 0.755 | 1128 | 1211 |
|                                                   | T94 | 0.354 | 0.881 | 1041 | 1117 |
|                                                   | T9  | 0.176 | 1.050 | 1162 | 520 |
|                                                   | T59 | 0.702 | 1.099 | 2740 | 812 |
|                                                   | Z48 | 0.550 | 1.415 | 1015 | 710 |
| Average                                          |     | 0.455 | 0.820 | 1344 | 861 |
| Low gas-yield wells with low water production (nine wells) | Z41 | 0.09  | 0.620 | 378  | –   |
|                                                   | T91 | 0.25  | 0.804 | 195  | –   |
|                                                   | T63 | 0.20  | 0.865 | 291  | –   |
|                                                   | Z49 | 0.067 | 0.979 | 499  | –   |
|                                                   | Z53 | 0.086 | 1.054 | 185  | –   |
|                                                   | T64 | 0.13  | 1.067 | 471  | –   |
|                                                   | T82 | 0.068 | 1.083 | 300  | –   |
|                                                   | T98 | 0.10  | 1.193 | 193  | –   |
|                                                   | T87 | 0.054 | 1.213 | 481  | –   |
| Average                                          |     | 0.116 | 0.986 | 333  | –   |
low level, and the gas desorption radius continues to expand gradually. Finally, when the gas desorption radius reaches to \( r_e \), the inter-well pressure interference is formed. At this time, CBM is desorbed in large quantity, and the production wells can reach a high gas yield (Figure 17(a)).

Figure 14. Dynamic characteristics of CBM wells with differing productivity. (a) Comparison of reservoir pressure, (b) comparison of drainage radius, and (c) comparison of gas content. The calculation methods of reservoir average pressure and drainage radius are quoted from Yan et al. (2019).
Figure 15. Relationship between reservoir permeability and average daily gas production.

Figure 16. Sketch of pressure perturbation area and gas desorption area. $r_c$ is the well-controlled radius, $r$ is the pressure perturbation radius, $r_{cd}$ is the gas desorption radius, $P_i$ is the initial reservoir pressure, $P_{cd}$ is the critical desorption pressure, $P_{wf}$ is the BHFP, $V_i$ is the initial gas content, $k$ is the relative permeability, $k_g$ is the gas relative permeability, and $k_w$ is the water relative permeability.
However, an unreasonable drainage strategy is not conducive to high gas production. The BHFP of a large number of low gas-yield wells drops rapidly when the reservoir has sufficient liquid supply capacity, resulting in decrease in reservoir pressure near the wellbore to below the critical desorption pressure and a large amount of CBM desorption. Multiple factors lead to reducing reservoir permeability, disabling the fracture, and limiting expansion of the pressure drop funnel. For example, the gas/water two-phase flow easily transports desorbed bubbles and the pulverized coal to block pore throats, and permeability near the wellbore is subject to effective stress, and so on (Huang et al., 2018; Lan et al., 2017). Ultimately, these lead to low gas production in CBM wells (Figure 17(b)).

It is worth noting that different drainage strategies should be adopted based on different reservoir conditions (Figure 18). Specifically, if the artificial fractures are vertical and the original reservoir permeability is high (>0.3 mD), water in the far formation can flow into the wellbore easily, resulting in the pressure perturbation radius and gas desorption radius
expands rapidly, that is the time of $t_1-t_2$ is short. By contrast, if the reservoir permeability is low (<0.3 mD) or the artificial fractures are horizontal, the BHFP should be kept stable after the well begins to produce gas. The purpose is to prevent reservoir damage by rapid depressurization and to cause the pressure perturbation radius and gas desorption radius expand outward gradually, so the time of $t_1-t_2$ is relatively long. Finally, production wells can reach high gas yield gradually with the gas desorption radius reaches to $r_e (t_2-t_3)$. At this time, the daily water production of CBM wells is less than 1 m$^3$/d and the BHFP drops to abandonment pressure.

**Figure 19.** Comparison of different drainage strategies at typical wells. BHFP: bottom-hole flowing pressure.
Well Z48 and Z49 were taken as examples to confirm the above conclusions (Figure 19). These two wells are adjacent to each other, with a spacing of less than 250 m, and have similar reservoir structure and geological parameters. Reservoir permeability is 0.23 mD, and the direction of fractures is vertical. However, due to the different drainage strategies employed at these two wells, characteristics of gas production are different in the later period. Under such geological conditions, the BHFP of well Z48 keeps synergistic decline with the reservoir fluid supply capacity, and the well can reach a high gas yield. Contrastively, the BHFP of adjacent well Z49 drops rapidly to less than 1 MPa in the early stage while the reservoir still has the ability to supply fluid at this time, so the gas production in the whole stage is less than 1000 m³/d. Furthermore, the drainage radius of well Z49 is substantially less than that of well Z48.

Conclusions
This paper analyses the characteristics and reasons of productivity differences at vertical CBM wells in the SZB from the view of geology and drainage, and makes suggestions for rational production of CBM wells based on the research results.

1. An analytical process for rational production of CBM wells is established. Production wells should follow a principle in order to achieve high yield. That is, wells should first be unaffected by faults, then have stress conditions and properties of the surrounding rock to make sure that the artificial fractures cannot penetrate aquifers, and finally be adopted the drainage strategy that matches reservoir fluid supply capacity. CBM wells will not achieve rational production unless all of these conditions are met.

2. For CBM production affected by the ingress of external water, the correlation degree of aquifer parameters to water production can be ordered from strongest to weakest as aquifer thickness, pore connectivity, porosity, and the shale content. While in the case of fractures that do not penetrate the aquifer, reservoir permeability has the largest impact on the productivity differences, and the burial depth and reservoir thickness have the least impact on.

3. The drainage strategy for CBM wells which are not affected by external water is optimized. BHFP and reservoir fluid supply capacity should be kept in synergistic decrease, and the reservoir fluid supply capacity is closely related to permeability and direction of fractures. For wells with permeability less than 0.3 mD or horizontal fracture, the BHFP should be kept stable after gas production. While for wells with permeability greater than 0.3 mD and vertical fractures, BHFP can gradually decrease. The purpose is to make the pressure perturbation radius and gas desorption radius reach the well control boundary, and eventually form the inter-well pressure interference.

Acknowledgements
We would like to thank China United Coalbed Methane Corporation for providing the production well date.

Declaration of conflicting interests
The author(s) declared no potential conflicts of interest with respect to the research, authorship, and/or publication of this article.
Funding

The author(s) disclosed receipt of the following financial support for the research, authorship, and/or publication of this article: This study was financially supported by the National Natural Science Foundation of China (Grant Nos. 41772159, 41872178, and U1910205) and the National Major Science and Technology Project of China (Grant No. 2017ZX05064003).

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