

Research Article

Optimal Injection Parameters for Enhancing Coalbed Methane Recovery: A Simulation Study from the Shizhuang Block, Qinshui Basin, China

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The injection of N₂ into coal reservoir has great potential in improving recovery of coalbed methane (CBM). In this study, a numerical model was established based on the GEM component model to evaluate the influences of different N₂ injection parameters (production injection well spacing, gas injection timing, gas injection duration, gas injection rate, and the bottom-hole injection pressure) on the production of CBM in the Shizhuang Block of Qinshui Basin, China. Based on the economic benefit of CBM production, the production increasing rate and nitrogen replacement ratio were established to optimize the N₂ injection parameters. The results show that (1) the production injection well spacing had the greatest influence on CBM production, followed by injection duration and the bottom-hole injection pressure, and injection timing and injection rate had a relatively small influence. (2) With increasing gas injection duration, injection rate, and the bottom-hole injection pressure, the rate of production increased and the nitrogen replacement ratio decreased. (3) The optimal N₂ injection scheme was revealed with the production injection well spacing of 180 m, the injection timing of a second year after gas production, an injection duration of 7 years, an injection rate of 5000 m³/d, and a bottom-hole injection pressure of 10 MPa. Under these conditions, the rate of production increasing rate, the nitrogen displacement ratio, and the regional recovery of the four production wells were 18.14%, 0.5, and 48.96%, respectively, some 8.88% higher than that without nitrogen displacement, showing good effect in terms of CBM production.

1. Introduction

Coalbed methane (CBM) is an important unconventional natural gas resource, and it is abundant in China. According to the fourth round of CBM resource assessment, the geological resources of shallow CBM at a burial depth of 2 km are $29.82 \times 10^{12} \text{ m}^3$ in China [1–5]. There are about 20,000 CBM wells at the end of 2020, and the CBM production is about $57.67 \times 10^8 \text{ m}^3$. The average gas production per well is generally low. It is not only affected by the complex geological conditions but also depends on the adaptability of CBM development technology. By the end of the 13th Five-

Year Plan, the production of CBM has gradually increased, but the increase is small. The CBM production still has not exceeded 10 billion cubic meters. At present, China's CBM industry is characterized by the low exploration and development, low adaptability of agent technology, low return on investment, small development scale, etc. [6–9]. Under the background of “peak carbon and carbon neutralization,” clean energy is in high demand. CBM industry needs to be closely linked around the value chain in terms of “how to improve the single CBM well production and the overall CBM recovery.” Therefore, CBM development needs to conduct the refine exploitation geology research and the

development of more targeted engineering technology research. This strengthens the geological and engineering technology integration evaluation and implements technology industrialization, which can achieve the goal of improving the development benefit of CBM and promote the development of China's CBM industry. Therefore, efficient techniques are needed to improve CBM recovery [10].

Exploitation of CBM mainly depends on drainage and pressure reduction, which promotes desorption of methane [11, 12]. Injecting N_2 can reduce the partial pressure of methane in a coal reservoir [13] and improve the permeability of coal reservoir [14], thus significantly improving the CBM production. Based thereon, a gas-injection technique is proposed, which is called "enhancing CBM recovery by injecting N_2 (N_2 -ECBM)" [15, 16]. Many laboratory and field tests have been conducted [17–23]. The adsorption of N_2 will cause the shrinkage of coal matrix when the N_2 is injected into coal, which mainly changes the mechanical properties and permeability of coal. After N_2 injection, the permeability of coal increases, and it can promote the diffusion and migration of CBM. Meanwhile, the mechanical strength of coal changes readily, which is conducive to improving CBM recovery. Additionally, some scholars explored and compared the results of N_2 injection and the mixture of N_2 and CO_2 injection [24]. The process is nonpiston displacement when N_2 displaces CH_4 . The breakthrough of N_2 occurs rapidly, and the two-element transition zone is narrow. The CH_4 and N_2 are produced for a long time after breakthrough. The ratio of N_2 injection is higher when the mixture of N_2 and CO_2 is injected into the coal, which can increase the permeability of the coal and is beneficial to CBM recovery. Most of the previous studies focused on the mechanism analysis of N_2 injection to enhance CBM recovery, however, less work on the effect of N_2 injection parameters on CBM recovery and the optimization of N_2 injection scheme has been undertaken.

The Shizhuang Block has realized the industrial development of CBM which shows considerable production volumes in the Qinshui Basin [25–27]. However, with the development of CBM, many CBM wells have been found to have low efficiency and low rates and amounts of overall productivity [28, 29]. To promote the long-term stable production of CBM in the area, it is necessary to enhance the recovery based on an N_2 -ECBM technique.

Therefore, in the present research, the production variations under different N_2 injection parameters (including the production injection well spacing, gas injection timing, gas injection duration, gas injection rate, and the bottom-hole injection pressure) in coal reservoir were studied using numerical simulation, to optimize the N_2 injection parameters and enhance CBM recovery. The results may provide theoretical guidance for an optimal N_2 -ECBM scheme in the study area.

2. Model Establishment

2.1. Geological Model. The Cartesian coordinate system was adopted for the reservoir grid model. The grid distribution is $51 \times 51 \times 1$. The length, width, and height of a single grid

are $10 \text{ m} \times 10 \text{ m} \times 6 \text{ m}$, and the model measures $510 \text{ m} \times 510 \text{ m} \times 6 \text{ m}$. Based on the five point well pattern, an N_2 injection well is located in the middle of the model, four production wells are located around the injection well, and the well spacing between the injection well and the four production wells is equal (Figure 1).

The Shizhuang Block is located in the south of Qinshui Basin (Figure 2). The target layer is the no. 3 coal seam. Previous studies have shown that its burial depth is 500–1300 m, the coal thickness is 4–10 m, and the gas content is $8\text{--}28 \text{ m}^3/\text{t}$ [30, 31]. Based on the above, basic parameters of the basic model are described as follows: the depth of the coal seam is 1000 m, the thickness of the coal seam is 6 m, and the gas content is $24 \text{ m}^3/\text{t}$. Thus, the geological reserves of CBM in this area amount to $57.8 \times 10^6 \text{ m}^3$; other basic parameters are listed in Table 1.

2.2. Numerical Model. A coal reservoir is the dual porosity system composed of matrix pores and fracture [32]. Matrix pores are the main gas storage area where CBM is present as an adsorption phase, and fracture controls the permeability of coal reservoir [33]. Therefore, the Gliman and Kazemi dual porosity model was adopted, which assumes that the matrix does not consider flow, and the fractures does [34].

In addition, the GEM component model was used to simulate the multicomponent fluid flow state in the process of N_2 -ECBM. According to the occurrence conditions of coal reservoir, the assumptions proposed by our predecessors were employed to set some basic settings of simplified operation in the model, namely: (1) there are two-phase flows of water and gas in the coal reservoir [35]. (2) The free gas in coal reservoir is an ideal gas [36]. (3) CBM experiences desorption, diffusion, and seepage processes, in which the desorption process conforms to the Langmuir model, the diffusion process is Fickian, and seepage in fractures conforms to Darcy's law [37, 38].

According to the conservation of mass and continuity equation, the balance equation of gas-water two-phase flow in fractured systems can be expressed as

$$\frac{\partial(\varnothing S_w/B_w)_f}{\partial t} = \nabla \cdot \left(\frac{kk_{rw}}{\mu_w B_w} (\nabla p_w - \rho_w g \nabla d) \right)_f - q_{fw} + q_{cwmf}, \quad (1)$$

$$\frac{\partial(\varnothing S_g/B_g)_f}{\partial t} = \nabla \cdot \left(\frac{kk_{rg}}{\mu_g B_g} (\nabla p_g - \rho_g g \nabla d) \right)_f - q_{fg} + q_{cgmf}. \quad (2)$$

The equilibrium equation of gas-water two-phase flow in the matrix system can be expressed as

$$\frac{\partial(\varnothing \rho_w S_w/B_w)_m}{\partial t} = -q_{cwmf}, \quad (3)$$

$$\frac{\partial(\varnothing \rho_g S_g/B_g)_m}{\partial t} = -q_{cgmf} + q_{md}, \quad (4)$$

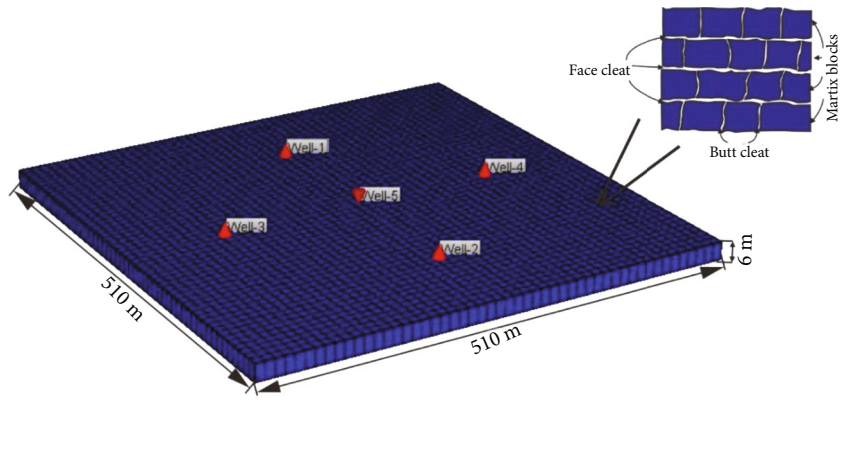


FIGURE 1: Geological model of coal reservoir in this study.

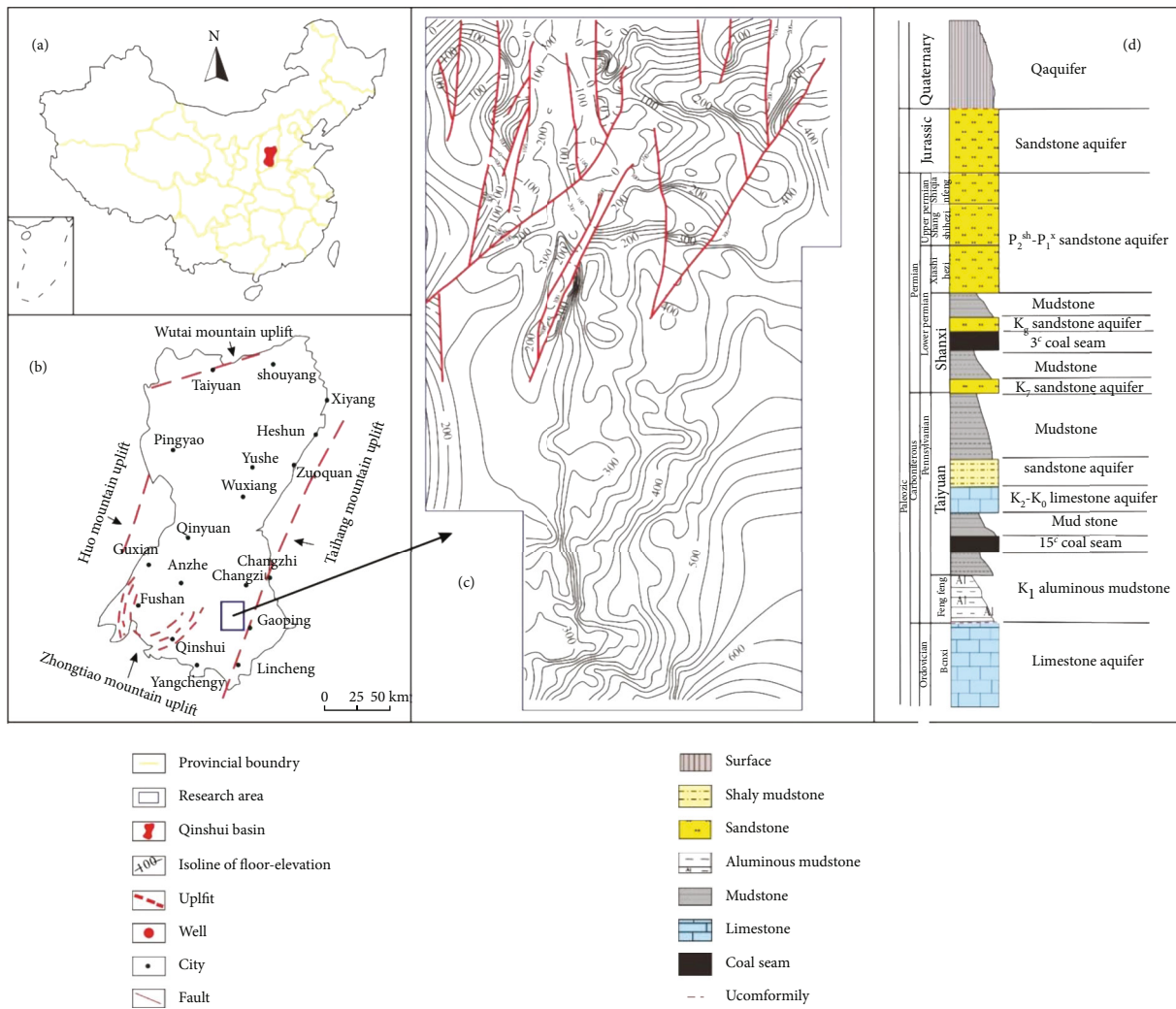


FIGURE 2: Locations of the study area and wells. (a) Location of the study area in China. (b) Location of the Shizhuang Block in the southern Qinshui Basin. (c) Topography of the study area. (d) Stratigraphic column of the coal-bearing strata [31].

TABLE 1: Basic parameters used in the numerical simulation.

Parameter	Value	Unit	Remark	Parameter	Value	Unit	Remark
Gas content	24	m ³ /t	Measurement	Reservoir temperature	25	°C	Well testing
Reservoir pressure	10	MPa	Well testing	Water viscosity	0.7	Cp	Empirical value
Buried depth of coal	1000	m	Measurement	Density of coal	1435	kg/m ³	Experiment
Coal seam thickness	6	m	Average value	Compressibility of coal	2 × 10 ⁻⁵	MPa ⁻¹	Empirical value
Langmuir volume of CH ₄	34.24	m ³ /t	Experiment	Matrix porosity	6	%	Experiment
Langmuir volume of N ₂	21.72	m ³ /t	Experiment	Fracture porosity	1	%	Empirical value
Langmuir pressure of CH ₄	3500	kPa	Experiment	Matrix permeability	0.01	mD	Experiment
Langmuir pressure of N ₂	3520	kPa	Experiment	Fracture permeability	1.0	mD	Well testing
Diffusion coefficient of CH ₄	4 × 10 ⁻⁶	cm ² /s	Empirical value	Matrix water saturation	1	%	Empirical value
Diffusion coefficient of N ₂	1.5 × 10 ⁻⁶	cm ² /s	Empirical value	Fracture water saturation	99	%	Empirical value

$$q_{md} = -\rho_{ga}\rho_c \frac{dV}{dt}, \quad (5)$$

where ϕ represents the porosity, ρ_w is the density of water, ρ_g is the density of gas, S_w is the saturation of water, S_g is the saturation of gas, μ_w is kinematic viscosity of water, μ_g is kinematic viscosity of gas, g is gravity acceleration, d is the coal burial depth, q_w is the production of water, q_g is the production of gas, q_{cwmf} is the water exchange capacity between the matrix and fracture, q_{cgmf} is the gas exchange capacity between the matrix and fracture, B_w is the water volume factor, B_g is the gas formation volume factor, ρ_{ga} is the gas density at standard conditions, ρ_c is the coal density, V is the average residual gas content in coal matrix, and subscripts f and m denote fracture and matrix.

Based on the studies of Redlich and Kwong [39] and Soave [40], the equations of state for gases are

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b)}, \quad (6)$$

$$a(T) = 0.42748 \frac{RT_c^2}{P_c} \left[1 + m \left(1 - \left(\frac{T}{T_c} \right)^{0.5} \right) \right]^2, \quad (7)$$

$$b = 0.086640 \frac{RT_c}{P_c}, \quad (8)$$

$$m = 0.48508 + 1.55171\omega - 0.15613\omega^2, \quad (9)$$

where R denotes the universal gas constant of 8.314 J/(mol •K), T_c is the critical temperature in K, P_c is the critical pressure in Pa, and ω is the acentric factor.

Binary mixed gas migrates in coal reservoir in the process of N₂ displacement [36]. Here, the subscript 1 and the subscript 2 represent CBM and injected nitrogen, respectively. The gas in coal reservoir is stored in adsorbed state and free state, and the content of adsorbed component can be expressed by the generalized Langmuir equation [41]:

$$C_1 = \frac{V_{L1}p_1b_1}{1 + p_1b_1 + p_2b_2}, \quad (10)$$

$$C_2 = \frac{V_{L2}p_2b_2}{1 + p_1b_1 + p_2b_2}, \quad (11)$$

where C is adsorption gas volume, V_L denotes the Langmuir volume constant, p represents gas pressure in matrix, and b is the Langmuir constant for gas component 1 and 2 which is equal to the reciprocal of the Langmuir volume, V_L .

Palmer and Mansoori [42] established a model to predict the change in coal permeability caused by coal shrinkage, which is applicable to the mixed gas adsorption/desorption equation:

$$\frac{\phi}{\phi_0} = 1 + c_f(p - p_0) + \frac{1}{\phi_0} \left(\frac{K}{M} - 1 \right) \left(\frac{\varepsilon_{L1}P(y_1/P_{L1}) + \varepsilon_{L2}P(y_2/P_{L2})}{1 + P((y_1/P_{L1}) + (y_2/P_{L2}))} - \frac{\varepsilon_{L1}P_0(y_{0,1}/P_{L1}) + \varepsilon_{L2}P_0(y_{0,2}/P_{L2})}{1 + P_0((y_{0,1}/P_{L1}) + (y_{0,2}/P_{L2}))} \right), \quad (12)$$

where ϕ represents the porosity, subscript 0 is the initial conditions, p_L is the Langmuir pressure, ε_L is the strains at infinite pressure, subscripts 1 and 2 denote CBM and injected nitrogen, c_f represents the fracture pore volume compressibility, M represents the constrained axial modulus, K is the bulk modulus, p is the pressure, $y_{0,1}$ and $y_{0,2}$ stand for

the composition of components 1 and 2 at the initial or reference conditions, and y_1 and y_2 refer to the composition of components 1 and 2 with pressure p .

2.3. *Simulation Scheme.* Previous studies have shown that the factors affecting the production increase of N₂ injection

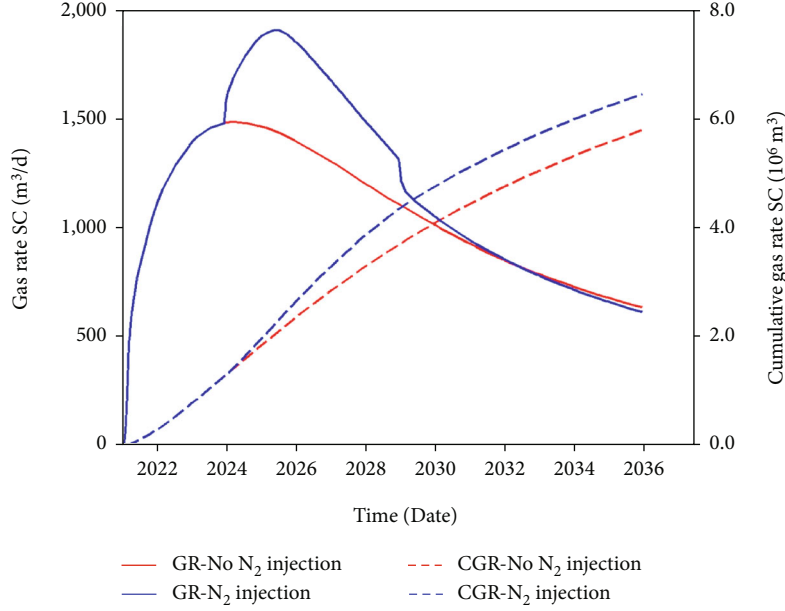


FIGURE 3: CBM production curves of N_2 injection displacement and no N_2 injection displacement in Well-1. GR denotes daily gas production, and CGR represents cumulative gas production. SC denotes surface condition.

in coal reservoirs are mainly limited by the spacing between production wells and injection wells, the timing of N_2 injection, the duration of gas injection, the rate of gas injection, and the bottom hole pressure of gas injection [13]. Therefore, the productivity of coal reservoir under different nitrogen injection production parameters was simulated based on the above factors.

According to the geological conditions of the Shizhuang Block, the basic nitrogen injection parameters were set as follows: the production injection well spacing is 150 m, the injection timing is the third year after gas production, the gas injection duration is 5 years, the gas injection rate is $4000\text{ m}^3/\text{d}$, and the bottom-hole injection pressure is 10 MPa. Compared with these, the influences of various nitrogen injection production parameters on CBM Recovery were analyzed to optimize the N_2 -ECBM production scheme.

To select the optimal parameters of N_2 injection for increasing production, the coefficient of production increasing rate (I) was established, and the increasing production effect of CBM under the influences of different factors was expounded, which provides a favorable basis for optimizing productivity.

$$I = \frac{C_i - C_0}{C_i}, \quad (13)$$

where C_i represents the total cumulative gas rate of parameter i , and C_0 is the total cumulative gas rate of coal reservoir without N_2 injection. The larger the value of I , the greater the effect of N_2 injection on increased production, the higher the recovery.

The value of I can characterize the stimulation effect of N_2 injection in coal reservoir, however, the economic benefit of coal reservoir should be considered, that is, the total

amount of nitrogen needed to be consumed. Therefore, the establishment of the coefficient replacement ratio (R) reflects the volume of methane that can be replaced by 1 m^3 of N_2 , to study N_2 injection into coal reservoir and consider the ensuing economic benefits.

$$R = \frac{C_i - C_0}{N_i}, \quad (14)$$

where N_i represents the total amount of N_2 injection with parameter i . The larger the value of R , the better the displacement effect of CH_4 by N_2 , and the higher the economic benefit.

3. Results

First, the real productivity of coal reservoir without N_2 displacement was simulated, and then the productivity of coal reservoir with basic N_2 injection parameters was taken as the control group for simulation, to provide the basis for analyzing different N_2 injection conditions when aiming to enhance CBM recovery. Based on the application of the above reservoir parameters and nitrogen injection production parameters, the bottom-hole injection pressure was controlled by the pressure drop rate of $0.1\text{ MPa}/\text{d}$. When the bottom-hole injection pressure dropped to 0.2 MPa , the bottom-hole injection pressure was kept unchanged and CBM production continues [43]. The model simulated the production capacity of four production wells in 15 years, and the gas-production time ranged from 2021 to 2036. Since the parameters of the four production wells were the same, Well-1 was taken as an example (Figure 3).

When the coal reservoir was not stimulated by N_2 injection, the cumulative gas flow per single well in 15 years was $5.79 \times 10^6\text{ m}^3$, the peak gas rate was $1486.8\text{ m}^3/\text{d}$, and the

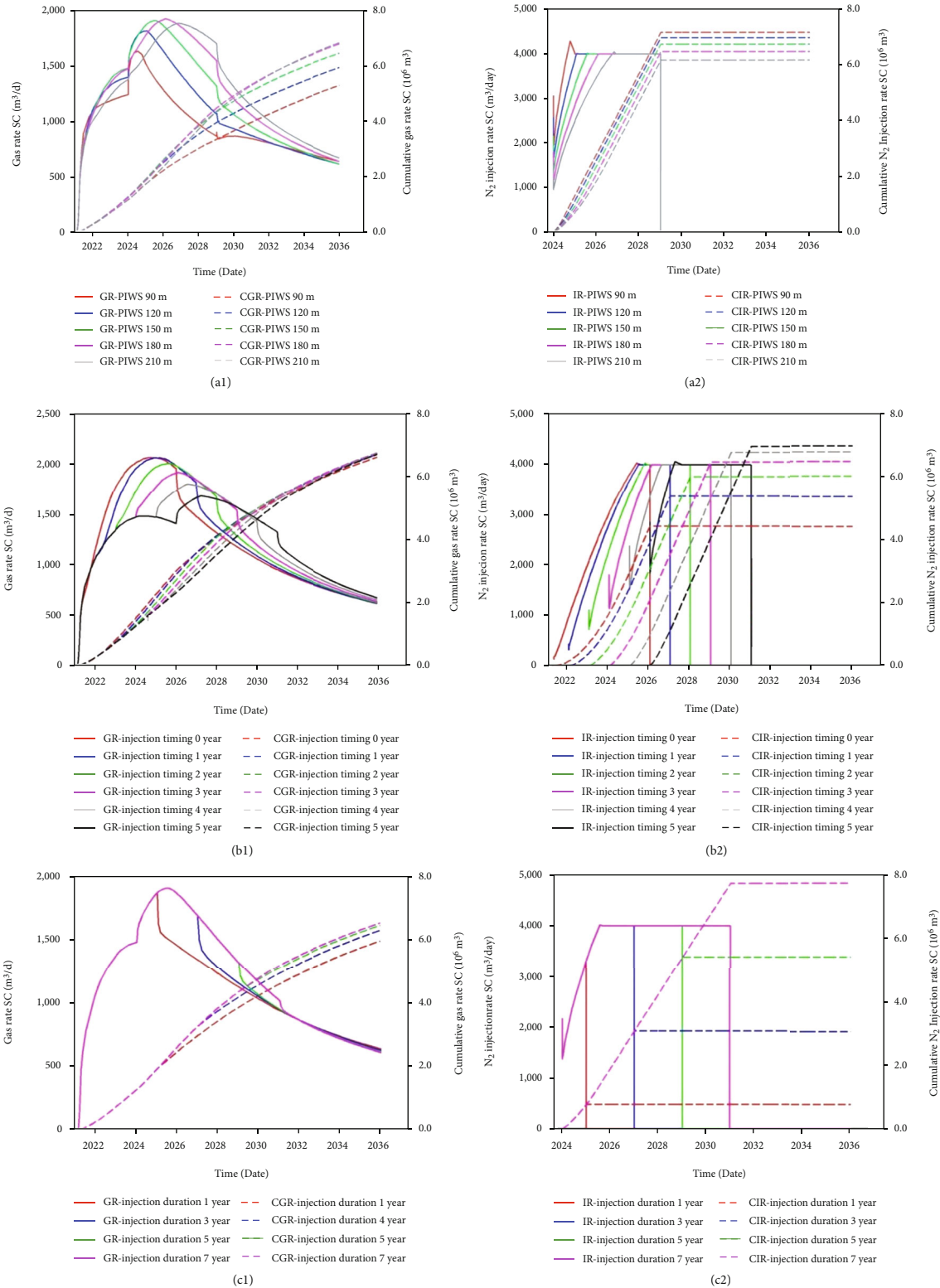


FIGURE 4: CBM production curves and N₂ injection curves under different N₂ injection production conditions: (a, c, and e) are CBM production curves of production injection well spacing, gas injection timing, and gas injection duration, respectively; (b, d, and f) are the N₂ injection curves of production injection well spacing, gas injection timing, and gas injection duration, respectively. PIWS stands for production injection well spacing, GR denotes daily gas production, CGR represents cumulative gas production, IR denotes daily gas injection, and CIR denotes cumulative gas injection. SC refers to surface condition.

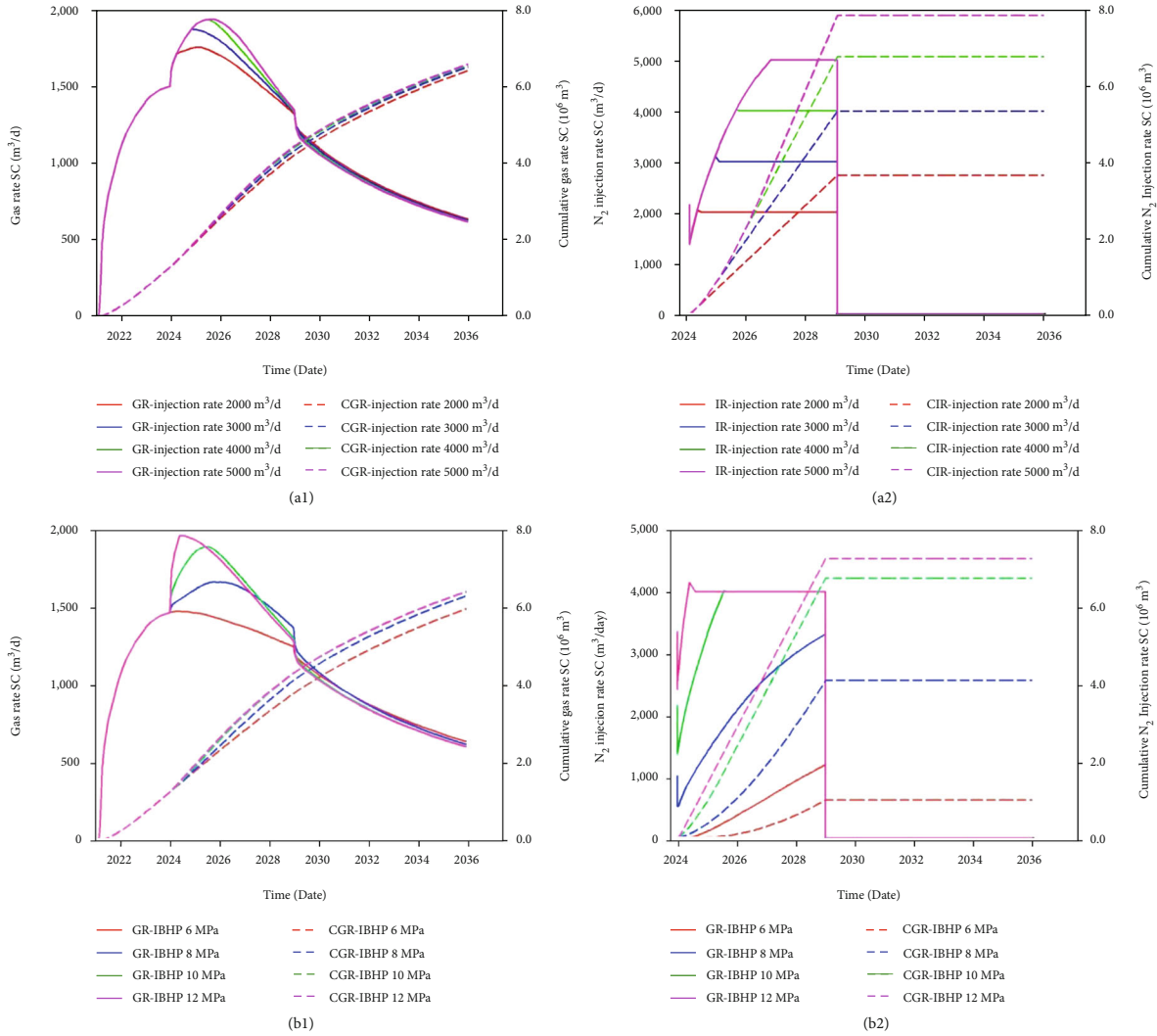


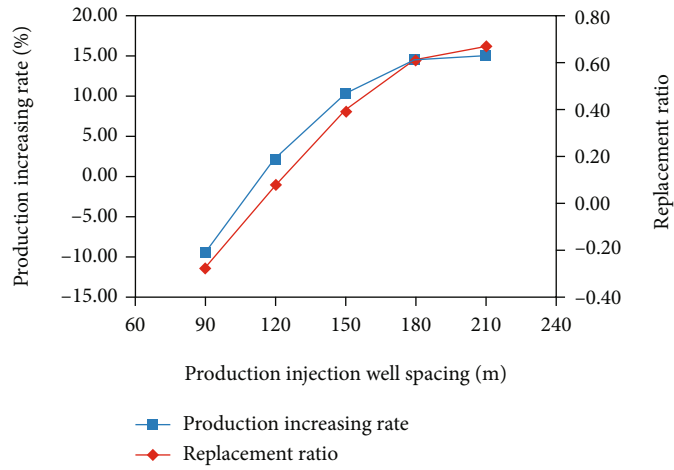
FIGURE 5: CBM production curves and N₂ injection curves under different N₂ injection production conditions: (a and c) are CBM production curves of gas injection rate and the bottom-hole injection pressure, respectively; (b and d) are N₂ injection curves of gas injection rate and the bottom-hole injection pressure, respectively. IBHP denotes the bottom-hole injection pressure, GR refers to daily gas production, CGR denotes cumulative gas production, IR represents daily gas injection, and CIR denotes cumulative gas injection. SC denotes surface condition.

average gas production amounted to 1057.65 m³/d. The cumulative gas rate of the four wells was 23.18 × 10⁶ m³, and the recovery factor was 40.08%. When the control group was subject to N₂ injection displacement production, the cumulative gas flow from a single well in 15 years increased to 6.46 × 10⁶ m³, the peak gas rate was 1909.43 m³/d, and the average gas rate was 1178.61 m³/d. The cumulative gas rate of the four wells was 25.83 × 10⁶ m³, the value of *I* was 10.26%, the value of *R* was 0.39, the recovery factor was 44.68%, the cumulative gas rate net increase was 2.65 × 10⁶ m³, and the recovery factor was increased by 3.88%.

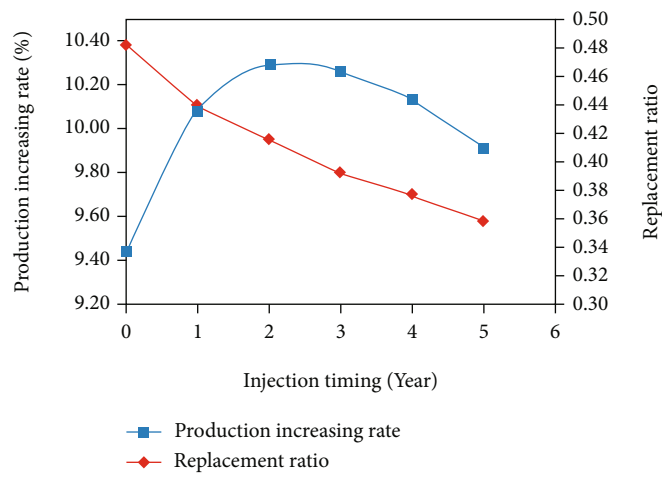
3.1. Production Injection Well Spacing. The simulation conditions are the same as the other parameters. On this basis, the productivity of production wells and N₂ injection wells with a spacing of 90 m, 120 m, 150 m, 180 m, and 210 m could be simulated, respectively. The simulation results indi-

cated that the longer the interval between production wells and injection wells, the longer the time to reach the peak gas rate. When the production injection well spacing was greater than 180 m to 210 m, the peak gas rate tended to decrease from 1922.42 m³/d to 1884.44 m³/d. The increase in cumulative gas rate was also small. The total cumulative gas rate of four wells was only increased by 19.08 × 10⁶ m³ (Figure 4(a)). Meanwhile, the smaller the production injection well spacing, the shorter the time for N₂ to reach the maximum N₂ injection rate, but the higher the total amount of N₂ injection (Figure 4(b)). The CBM recovery factor was then 36.62%, 41.03%, 44.68%, 46.98%, and 47.31% according to the respective well spacing.

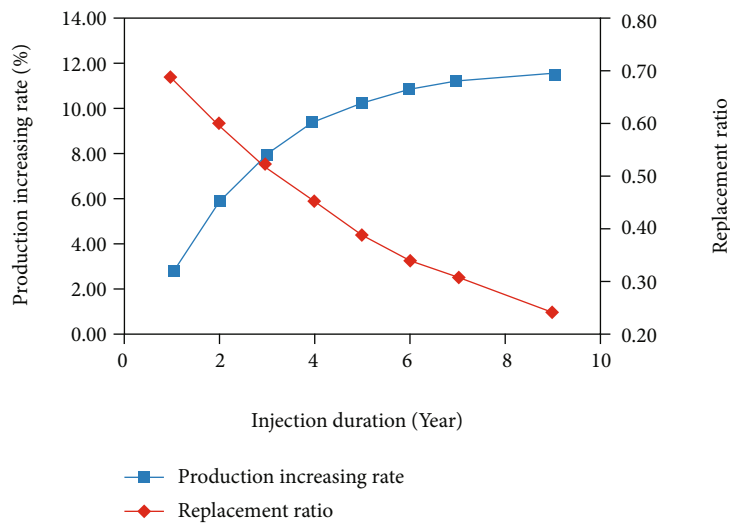
3.2. Gas Injection Timing. To analyze the influences of different injection timings on N₂-ECBM, the N₂ injection productivity of injection wells in 0, 1, 2, 3, 4, and 5 years after gas



(a)



(b)



(c)

FIGURE 6: Continued.

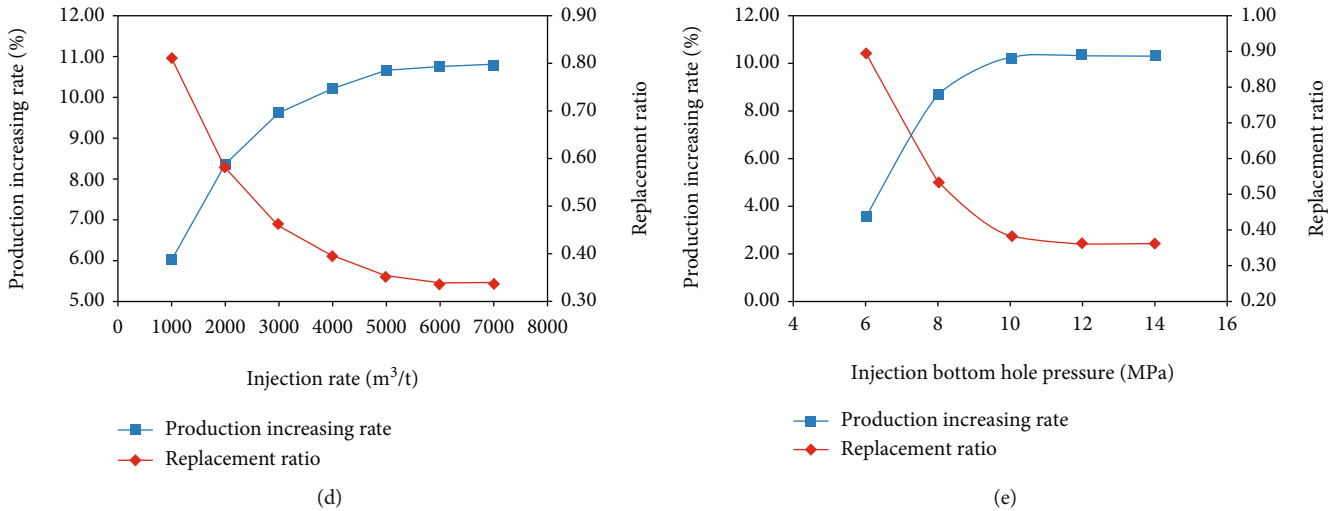


FIGURE 6: (a–e), respectively, describe the production increasing rate and replacement ratio of production injection well spacing, gas injection timing, gas injection duration, gas injection rate, and the bottom-hole injection pressure.

production was simulated, respectively. According to the simulation results (Figures 4(c) and 4(d)), when the gas injection timing was one year after gas production, the gas rate peak value was the largest, reaching 2003.92 m³/d, but, in general, the influence of gas injection timing on cumulative gas rate was small. Meanwhile, the total amount of N₂ injection was 501.46 × 10⁶ m³, 591.35 × 10⁶ m³, 640.5 × 10⁶ m³, 675.48 × 10⁶ m³, 692.26 × 10⁶ m³, and 711.02 × 10⁶ m³, which increased with the delay of injection timing. The recovery factors of CBM were 44.28%, 44.59%, 44.70%, 44.68%, 44.61%, and 44.51%, respectively. The trend was that the recovery factor first increased, then decreased, reaching a maximum in the second year.

3.3. Gas Injection Duration. The productivity of injection wells with an N₂ injection duration of 1 year, 3 years, 5 years, and 7 years was simulated, respectively. According to the simulation results (Figures 4(e) and 4(f)), when the injection duration exceeded 3 years, the gas rate peak value increased to 1909.43 m³/d and then did not increase. With the increase of the injection duration, the cumulative gas rate increased, but the growth rate decreased. The total cumulative gas rates of the four wells were 2383.84 × 10⁶ m³, 2516.92 × 10⁶ m³, 2582.56 × 10⁶ m³, and 2611.36 × 10⁶ m³, and the total amount of N₂ injection also increased. The recovery factors of CBM were 41.24%, 43.55%, 44.685%, and 45.18%, respectively.

3.4. Gas Injection Rate. The simulation conditions were set to match the other parameters. On this basis, the productivity of injection wells with N₂ injection rates of 2000 m³/d, 3000 m³/d, 4000 m³/d, and 5000 m³/d could be simulated. According to the simulation results (Figures 5(a) and 5(b)), the effect of injection rate on cumulative gas rate was relatively small, and the peak gas rate was 1729.56 m³/d, 1843.24 m³/d, 1909.43 m³/d, and 1909.89 m³/d, respectively. The total amount of nitrogen injection was 364.07 × 10⁶ m³, 532.66 × 10⁶ m³, 675.48 × 10⁶ m³, and 784.05 × 10⁶ m³,

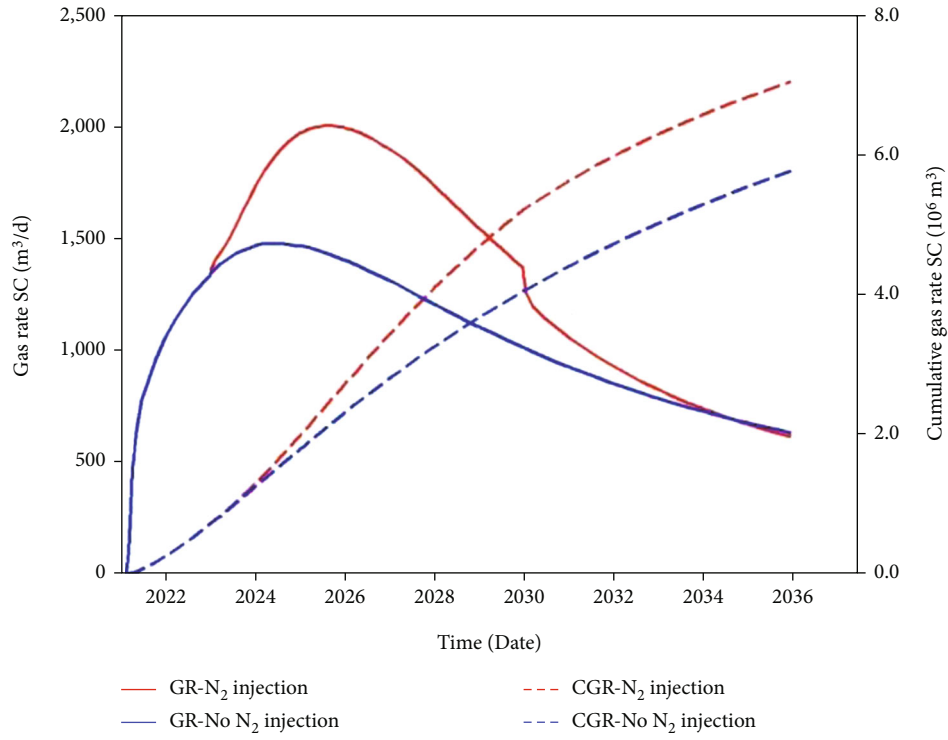
which increased with the increase in N₂ injection rate but also decreased in the later period. The recovery factors of CBM were 43.76%, 44.36%, 44.68%, and 44.89%, respectively.

3.5. The Bottom-Hole Injection Pressure. The bottom-hole injection pressure could push the injected gas into the pore and fracture space of coal reservoir, compete with methane for adsorption, reduce the partial pressure of CBM, and then promote methane desorption. To study the influence of the bottom-hole injection pressure on N₂-ECBM, the productivity of 6 MPa, 8 MPa, 10 MPa, and 12 MPa injection pressure was simulated by increasing the injection pressure of 2 MPa. Through comprehensive analysis of the gas rate (Figures 5(c) and 5(d)), the higher the bottom-hole injection pressure, the larger the peak gas production, the maximum value was 1976.9 m³/d, and the shorter the time to reach the gas rate peak value. At the same time, the cumulative gas rate and the total amount of N₂ injection were larger, but the increase was smaller, which indicated that higher injection pressure was not an ideal parameter for optimization of the technique. The CBM recovery factors were then 41.65%, 43.92%, 44.68%, and 44.72%, respectively.

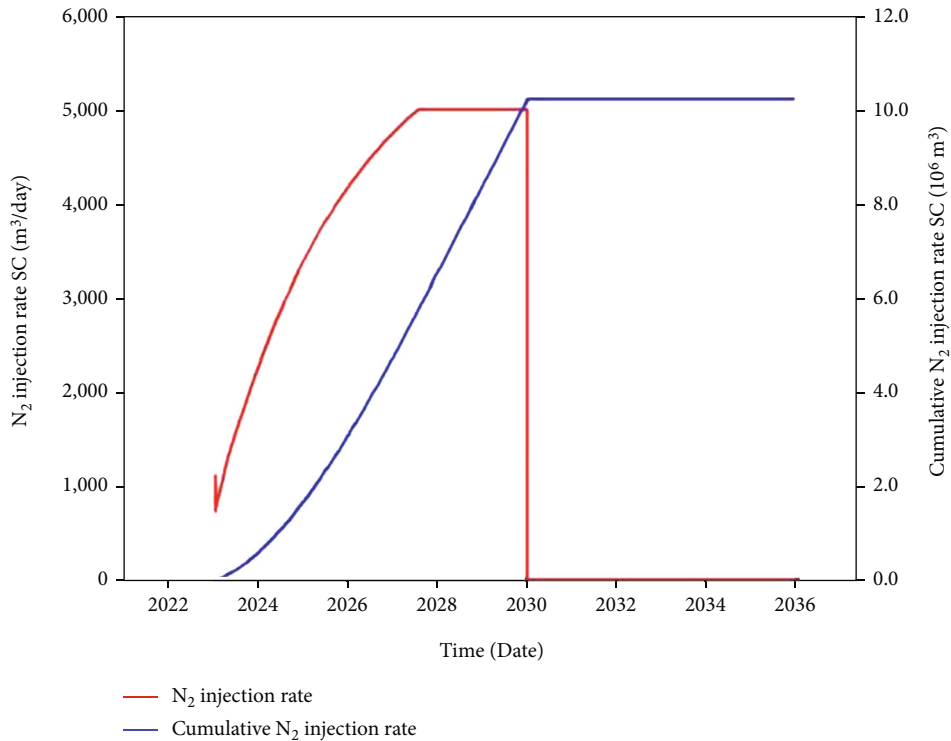
4. Discussion

The results show that the production parameters of N₂ injection, such as production injection well spacing, gas injection timing, gas injection duration, gas injection rate, and the bottom-hole injection pressure, have a significant impact on N₂-ECBM. Therefore, it is necessary to use the values of *I* and *R* to analyze the stimulation and economic applicability of various control factors for N₂ injection in a coal reservoir in more depth.

4.1. Production Injection Well Spacing. Both N₂ injection and CBM drainage were realized by reducing the pressure of coal reservoir through drainage. When the well spacing was less



(a)



(b)

FIGURE 7: The CBM production curves and N₂ injection curves of N₂ injection optimized displacement and no N₂ injection displacement. GR denotes daily gas production, and CGR denotes cumulative gas production. SC denotes surface condition.

than the radius of influence of each well, the depression funnels formed in the drainage process of production wells would overlap, resulting in inter-well interference, which would increase the corresponding development cost and

worsen the economic effect. However, if the well spacing was too large, the drainage and depressurization effect would be affected, and the N₂ injectability would be reduced [44]. Therefore, choosing the right spacing between production

wells and injection wells was conducive to obtaining the best N_2 -ECBM effect. Based on numerical simulations of productivity, the production increasing rate I and the replacement ratio R of different production injection well spacings were calculated (Figure 6(a)), and the production increase and replacement efficiency under five spacings were revealed. The results indicate that I and R increased with the increase of production injection well spacing, which indicated that the increase of well spacing was beneficial to the increase of production and economy of coalfield. However, when the well spacing exceeded 180 m, I tended to remain unchanged and R increased greatly. Considering the boundary problem of geological model, the optimal production injection well spacing should be 180 m.

4.2. Gas Injection Timing. By changing the timing of gas injection, its influences on the production increasing rate of coal reservoir N_2 injection and its economics could be studied (Figure 6(b)). The results show that the later the gas injection timing was, the smaller the R was, and the less economical it was, but I first increased, then decreased, reaching its peak in the second year after gas production. It showed that the best time for gas injection was the second year after gas production, but the economic benefit was general. Considering that the main benefit of coal field was the increase of production, the best time of gas injection was the second year after gas production.

4.3. Gas Injection Duration. Through the numerical simulation of the production capacity under different injection durations, the control of the injection duration on the production increasing of N_2 injection and the economy of the total amount of N_2 injection were obtained. The results (Figure 6(c)) showed that, with the increase of injection duration, I increased and R decreased, indicating with the increase of N_2 injection amount, the production increasing rate of coal reservoir increased, but the efficiency of use of N_2 decreased, and the amount of waste increased. Moreover, the longer the gas injection duration, the rate of production increase tended to be flat. Considered comprehensively, the production capacity with a gas injection duration of 7 years should be selected.

4.4. Gas Injection Rate. By changing the gas injection rate, the productivity simulation results (Figure 6(d)) imply that when the injection rate was less than $4000 \text{ m}^3/\text{d}$, with the increase of the injection rate, I increased rapidly, R decreased sharply, and finally tended to slow down. The finding showed that increasing the gas injection rate was beneficial to the increase of coalfield production, but it would reduce the rate of utilization of N_2 and weaken the economic effect of coalfield production. Considered comprehensively, a rate of injection of $5000 \text{ m}^3/\text{d}$ was optimal.

4.5. The Bottom-Hole Injection Pressure. By changing the bottom-hole injection pressure, the increases in production benefit and economic benefit of N_2 injection in the coal field were analyzed. The results (Figure 6(e)) show that the influences of the bottom-hole injection pressure, injection rate, and injection timing on N_2 injection in coalfield had a sim-

ilar trend. With the increase of the bottom-hole injection pressure, I increased and R decreased, and when the pressure exceeded 10 MPa, the rate of production increase and replacement ratio tended to be constant. On the one hand, the higher N_2 injection pressure in the fracture would increase the N_2 diffusion from the fracture system to the coal matrix system and lead to the earlier breakthrough of N_2 , which would increase the industrial cost of N_2 and CH_4 separation in the N_2 -ECBM process. On the other hand, if the N_2 injection pressure was too low, it was not conducive to gas injection and migration. Considered comprehensively, it was more appropriate to choose a bottom-hole injection pressure of 10 MPa.

4.6. Scheme Optimization. As mentioned above, the injection of N_2 reduced the partial pressure and concentration of methane in the fracture system, caused desorption of methane on the coal surface and contraction of the coal matrix [45, 46], promoted the exploitation of methane, and improved the recovery of CBM. Therefore, according to the above summary, the production parameters of N_2 injection optimization scheme were designed as follows: the production injection well spacing was 180 m, the injection timing was two years after gas production, the injection duration was 7 years, the injection rate was $5000 \text{ m}^3/\text{d}$, and the bottom-hole injection pressure was 10 MPa. The simulation results are shown in Figure 7.

Figure 7 demonstrates that, compared with the case of no nitrogen displacement production, the average gas rate, daily gas peak value, and cumulative gas rate increased significantly when nitrogen injection displacement production was implemented under the proposed scheme. The cumulative gas rate per single well in 15 years was $7.07 \times 10^6 \text{ m}^3$, increasing by 22.1%, the peak gas rate was $2011.44 \text{ m}^3/\text{d}$, increasing by 35.3%, and the average gas rate was $1291.27 \text{ m}^3/\text{d}$, increasing by 9.6%. The cumulative gas rate of the four production wells was $28.29 \times 10^6 \text{ m}^3$, I was 18.34%, R was 0.5, and recovery factor was 48.95%. Compared with the case with no displacement, the cumulative gas rate net was increased by $5.11 \times 10^6 \text{ m}^3$, and the recovery factor was increased by 8.88%. The simulation results were well verified in the physical experiment [47].

5. Conclusion

In this study, an N_2 -ECBM numerical model was established to study the effects of various N_2 injection parameters on the production of CBM, and the values of I and of R were established to optimize the N_2 injection parameters. The following conclusions were drawn:

- (1) The stimulation effect of N_2 displacement is related to the production injection well spacing, injection timing, injection duration, injection rate, and the bottom-hole injection pressure. Among them, the production injection well spacing has the greatest influence on methane cumulative gas rate, followed by injection duration and the bottom-hole injection

pressure, while injection timing and injection rate have relatively little effect

- (2) In the process of displacement, N₂ injection can significantly improve the gas production of CBM. The gas production of production wells increases rapidly in the early stage, reaches its peak value, and then decreases. At the end of N₂ injection, the gas rate decreases greatly and then decreases steadily in the later stage
- (3) With the increase of the production injection well spacing, the production increasing rate and nitrogen replacement ratio of coal reservoir increase. However, with a delay to the timing of the gas injection, the replacement ratio of nitrogen injection in a coal reservoir decreases, and the rate of production first increases and then decreases. Injection duration, injection rate, and the bottom-hole injection pressure have similar controlling effects on N₂-ECBM, manifest as an increased rate of production and a decrease in the nitrogen replacement ratio
- (4) The best nitrogen injection scheme is as follows: the production injection well spacing should be 180 m, the injection should occur in the second year after gas production, the injection duration should be 7 years, the injection rate should be 5000 m³/d, and the bottom-hole injection pressure should be 10 MPa. Under these conditions, the cumulative gas rate of four production wells is 28.29×10^6 m³, which is 5.11×10^6 m³ greater than that without nitrogen displacement, the recovery rate is 48.96%, and the net increase therein is 8.88%.

Data Availability

The data used to support the findings of this study are included within the article.

Conflicts of Interest

The authors declare no conflicts of interest.

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