Research Article

Development Evaluation and Optimization of Deep Shale Gas Reservoir with Horizontal Wells Based on Production Data

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The implementation of horizontal wells is a key to economic development of the deep shale gas reservoir. In order to optimize the key parameters for drilling, stimulation, and the production system, the development effect of a horizontal well in deep shale gas formations was investigated from various aspects in this study. The drilling, fracturing, and production performances of this well were analyzed combining with the geological characteristics. The main technical problems and key factors that restrict the gas well performance and estimated ultimate recovery (EUR) were clarified. Through the integrated study of geology and engineering, the optimization strategies for increasing gas production and EUR are provided. The Z2 area, where the Z2-H1 well is located, has good reservoir physical properties, which bring a high drilling efficiency. However, there are still some problems during its development, such as poor fracture extension both horizontally and vertically, limited stimulated reservoir volume (SRV), rapid production declining, large water production, and serious liquid accumulation. In this study, a comprehensive approach was proposed that can improve single-well production and EUR by optimizing the target position, horizontal section length, pathway, spacing, new drilling and fracturing technology, and production system.

1. Introduction

In recent years, with the expanding exploration and development of shale gas and the increasing demand of gas production, the development of deep shale gas (depth between 3,500 m and 4,500 m) attracted more and more attention [1, 2]. According to the latest resource evaluation results of the Ministry of Land and Resources of China in 2016 [3], China's shale gas recoverable reserve is around 21.84 trillion cubic meters. The Wufeng formation and Longmaxi formation in southern Sichuan [4] are the most favorable regions. However, these shale gas resources are generally buried deeply, 84% of which are distributed deeper than 3,500 meters [5, 6].

For the shallow shale gas reservoir (depth less than 3,500 m), China has entered the phase of large-scale development [7]. As for the deep shale gas, which has a geological reserve of $8 \times 10^{12} \text{ m}^3$ for the deep marine shale gas in China, China has initially break through technological and commercial difficulties [8].

With multistage tectonic movement, the geological conditions of deep shale gas in Sichuan Basin [4] are complex. Compared with the shallow shale gas reservoir, the deep shale gas reservoir attains various special properties, such as more developed fault with more natural fractures, higher content of brittle mineral, higher elastic modulus and position's ratio, higher formation pressure coefficient,

breakdown pressure, and horizontal stress difference. They all bring more difficulty during drilling and development in a deep shale gas reservoir [9–11]. The exploration and development technology of shale gas in the United States cannot be simply replicated. More technological difficulties need to be solved to achieve large-scale economic development [12]. The Z2-H1 well is a horizontal well deployed in the deep shale gas formation of southern Sichuan. The purpose of this well is to test the drilling and volumetric fracturing technologies of horizontal wells in deep shale gas formation, as well as to evaluate the production capacity of the fault anticline structure. The well was placed in June 2018 and was tested with daily gas production of $45.67 \times 10^4 \text{ m}^3$. It demonstrates good prospects for deep shale gas exploration and development in southern Sichuan [13, 14]. However, the long-term production is not satisfactory, and further understanding is needed. In this study, The Z2-H1 well was taken as an example, its geological features, drilling implementation effect, hydraulic fracture evaluation, dynamic characteristics of production and development are analyzed and optimization strategies are proposed to improve single-well production. This study would provide a foundation for the future development of horizontal wells and guidance for the exploration and development of deep shale gas in southern Sichuan.

2. Basic Geological Characteristics

The Xishan anticline, where the Z2-H1 well is located, is on the junction of the southern Sichuan low-steep tectonic belt and the gently structured tectonic belt in the middle of Sichuan Basin. The structure was formed during the multi-stage tectonic movements of the braided tectonic belt in the southeastern Sichuan Basin [4]. The depth of Wufeng formation-Longmaxi formation is mainly distributed between 3,500 m and 4,500 m. At present, the Wufeng formation-Longmaxi L_1 sublayer of the main shale gas reservoir in Sichuan Basin [5] is a large continuously distributed marine shale formation developed in the deep water continental shelf sedimentary environment, and the thickness in the study area is 30–60 m. The main lithology of the target layers in this area is siliceous shale, and the brittle mineral content (for example, quartz, feldspar, and carbonate minerals) is high [2]. The abundance of organic matter is high, and the organic matter is type I kerogen, which is in postmaturity (measured Ro value is between 2.04% and 2.27%) phase. The source rock has strong hydrocarbon generation capacity. The storage space contains organic pores, inorganic pores (intergranular pores and intragranular pores), microfractures, and other types, and its porosity is lower than that in the Weiyuan and Changning areas. Type I+II that are basically the same as those in the Weiyuan and Changning areas as high-quality shale reservoirs, among which $S_1L_1^{1-1}$ and Wufeng formations have the best reservoir quality. In addition, shale gas reservoirs in this area have good storage conditions. It is a deep and overpressure gas reservoir with a pressure coefficient of 1.86. Natural fractures of the shale in the Wufeng formation-Longmaxi L_1 sublayer are relatively developed and filled with calcite mostly.

3. Development Evaluation

3.1. Drilling Evaluation. For the Z2-H1 well, the wellbore length is 5,636 m. The horizontal section depth is 3,720–3,924 m. The horizontal section length is 1,526 m, with the maximum well inclination of 90.62° . The maximum full angle change rate is $9.74^\circ/30 \text{ m}$. The average mechanical drilling rate is 3.97 m/h, and the drilling period is 114.6 d. The well profile is designed as the “four spud and four completion,” and the oil-based drilling fluid used in Longmaxi formation has a density of $2.07\text{--}2.08 \text{ g/cm}^3$. Both of the well profile and drilling fluid can satisfy the safe operation.

The “PDC+screw/twisting” composite drilling method is used on the vertical section of the Z2-H1 well, which has a good effect on speeding up during drilling. As for the inclined section and the horizontal section, the comprehensive geosteering technologies, including drilling guided tool, azimuth gamma, and element logging, are used, which improves the smoothness of the wellbore and guarantees the cementation of the horizontal section to be 100% qualified. In the meantime, the drillability of high-quality shale reservoirs is also guaranteed, with 77% in the $S_1L_1^{1-1}$ segment and 23% in Wufeng formations, respectively (Table 1). The drilling efficiency of Class I+II reservoirs is 100% (with the reservoir drilling efficiency of Class I 91%), which lays a solid geological foundation for high shale gas production [8]. In addition, Q125 grade steel oil string with the 139.7 mm outer diameter and 12.7 mm wall thickness, no deformation occurs during fracturing.

3.2. Hydraulic Fracturing Evaluation. There are two technical difficulties during the development of deep shale gas. Firstly, the fracture conductivity is not high enough to support the high production of shale gas. Secondly, the fracture is not complex enough to fully stimulate the reservoir [15, 16]. In order to stimulate the Z2-H1 well better, the new generation of volumetric fracturing concept of deep shale gas in North America was adopted to handle some problems, such as the deep reservoir (about 4,000 m), large horizontal stress difference (19.5 MPa), high breakdown pressure (104 MPa), microfracture development, and difficulty in proppant carrying. The parameters were optimized to improve the fracture conductivity and complexity. High pumping rate fracturing processes were used to carry out volume hydraulic fracturing, including slick water, 40/70 mesh ceramic proppant, soluble bridge plug, dense fractures, large volume proppant, and temporary blocking and diversion.

The completion of the Z2-H1 well consists of 29 main fracturing stages, with an effective fracturing section length of 1493.81 m. The stage spacing was reduced to about 50 m; the cluster spacing was shortened from about 25 m to less than 15 m. The cumulative injection volume was more than $55,000 \text{ m}^3$. The average liquid strength was $36.1 \text{ m}^3/\text{m}$. The total sand volume was more than 3,300 t. The average proppant strength was 2.24 t/m. The pumping rate was increased from $8\text{--}12 \text{ m}^3/\text{min}$ to $12\text{--}14 \text{ m}^3/\text{min}$. The pumping pressure was increased from 77–80 MPa to 91.5 MPa. Slug sanding is adopted with low viscosity slick

TABLE 1: Drilling technology system of Z2-H1.

Spud order	Drilling tools and techniques	Drilling fluid system	Drilling fluid density (g/cm ³)
1 st	PDC+tower/screw	Polymer	1.06-1.22
2 nd	PDC+screw	KCl-polymer/potassium-polysulfonate	1.17-1.42
3 rd	PDC+screw	Potassium-polysulfonate drilling fluid	1.97-2.11
4 th	PDC+rotary guidance+screw/routine	Oil-based drilling fluid	2.11-2.21
Spud order	Drilling tools and techniques	Drilling fluid system	Drilling fluid density (g/cm ³)

water, and the temporary plugging agent is added on the stages which develop natural fractures.

The fracturing effect of this well has the following characteristics: (1) the fracture complexity is relatively high. With the fracturing process going and the distance and quantity of the postpressure microseismic points increasing continuously, the stimulation volume increases and the fractures are more complicated. Hydraulic fractures are mainly composed of network fractures. Ground microseismic monitoring results show that the SRV is 86.15 million cubic meters. (2) High pumping rate with dense fractures is helpful to the effective expansion of fractures. The overall pumping rate is maintained at 12-14 m³/min. The average net pressure in each section is only 10.13 MPa, which is less than the horizontal stress difference of 19.5 MPa. There are well correlations between the net pressure and flow rate, as well as the net pressure and fracture complexity index. At the same time, the pumping rate also has a significant correlation with single-stage SRV. (3) Adding a temporary plugging agent can help realize the temporary blocking and diversion. On the 21st to the 29th section (except 24th) of the well, the temporary plugging agent with a particle size of 20-60 meshes was added. Thereafter, the pumping pressure of each section increased by 2.0-6.0 MPa. The microseismic results indicate that the effects of temporary blocking and diversion are obvious (Figure 1).

3.3. Dynamic Production Characteristics. The well condition of Z2-H1 is complicated. After the blow-off test, production began on July 30, 2018. During this period, as shown in Figure 2, the underground well unblocking, placing of production tubing, production logging, and other operations were carried out. As of January 18, 2019, cumulative production time was 148 days, with a total gas production of 8.47 million cubic meters, a cumulative liquid production of 17,209 m³, and a flowback rate of 30.31%. At present, daily gas production is 44,500 m³, with the surface casing pressure of 8.14 MPa, the wellhead pressure of 1.37 MPa, and the daily water production of 68.5 m³.

3.3.1. Declining Characteristics. At the beginning, production was controlled at 50,000 m³ per day and the pressure drawdown was also limited within a reasonable range. Under this production method, the monthly decline rate of wellhead pressure was 36.34%, as shown in Figure 3. On September 23, 2018, the production was changed to unlimited pressure drawdown. At this condition, the initial maximum daily gas production was 170,000 m³ and the pressure was 35.59 MPa. The monthly decline rate is 47% on this stage, and the

decline rate is faster. The X2 well is a horizontal well changed from a vertical well, which is next to the Z2-H1 well and has the similar geological background with Z2-H1 well. So the overall development of these two wells is comparable. From the trend of wellhead pressure, it is obvious that with the increase in gas production, the wellhead pressure of both wells is decreasing, and the pressure of the Z2-H1 well falls faster. When producing the same gas volume, the wellhead drawdown of the Z2-H1 well is larger. This indicates that the X2 well had better gas production.

Considering the complicated changes in the production method of the Z2-H1 well, the regularized production method was used during the decline comparison with the well X2. This method couples the interaction between drawdown pressure and production, which can eliminate the production and pressure fluctuation caused by the change of the working system. The calculation of normalized production q_N is

$$q_N = J_g \times (m(p_r) - m(p_{ab})) = q_g \frac{m(p_r) - m(p_{ab})}{m(p_r) - m(p_{wf})}, \quad (1)$$

where $m(p)$ is the gas pseudopressure, MPa²/cp; p_{ab} is the abandonment pressure, MPa; and p_r is the average pressure of the gas reservoir, MPa.

From the comparison results, the decline rate of the normalized production of the well Z2-H1 is obviously faster than that of the X2 well. This indicates that the production of X2 well is relatively better. Furthermore, liquid production in the Z2-H1 well is instable.

3.3.2. Flow Characteristics. On October 10, 2018, a pressure gauge was sent to measure the pressure gradient and flowing temperature gradient, so that the flow characteristics could be analyzed (Figure 4). The test result shows that the flowing pressure gradient near the bottom of the well increases significantly, which indicates that the gas well with liquid cannot produce well.

From November 26th to November 30th, 2018, the production logging was performed on the bottom of the well (Figure 5). The results show that there are only 6 perforated intervals above the liquid level (3,761.3 m). These 6 intervals that contributed to 42.5% of the total gas production are concentrated near the upper middle part of point A. The remaining 23 intervals, that is, a total of 68 clusters are below the liquid level, contributing 57.5% of the total gas production. There are 15 clusters having no gas production contribution.

(a) Microseismic response in section 24th (without temporary plugging agent)

(b) Microseismic response in section 28th (with temporary plugging agent)

FIGURE 1: Comparison of microseismic response without and with a temporary plugging agent.

During the production logging, the slope of the log-log plot of the build-up test is $1/2$, as shown in Figure 6, which is the characteristic of infinitely conductive flow in large

fractures. The average half-length of the effective fracture is 34.22 m, which indicates a limited scope of hydraulic fracturing. What should be pointed out is that, due to the short

FIGURE 2: Z2-H1 well production curve.

FIGURE 3: The relationship between regularized production and production time of the Z2-H1 and X2 wells.

FIGURE 4: Flowing pressure and vertical depth of Longmaxi formation and Wufeng formation.

shut-in time, the pressure has not been recovered to the highest value. Overall, there are some uncertainties in the well test interpretation results.

3.4. Development Effect Evaluation. The extended exponential index method, the hyperbolic decline method, and the Duong method were used to evaluate the EUR of the Z2-H1 well [17, 18], with the results of 34 million cubic meters, 49 million cubic meters, and 66 million cubic meters, respectively. There is a significant difference between various methods, among which the predicted EUR of the extended exponential index is the most pessimistic and the predicted EUR of the Duong method is the most optimistic. Considering that the production decline analysis can only use the data on the production decline stage, its production history is too short. Therefore, an analytical model for the fracturing stage

FIGURE 5: Production logging interpretation.

FIGURE 6: Log-log plot of well test interpretation.

of the Z2-H1 well was established [19–21], which can comprehensively consider the production and pressure on the early stable production stage and the declining stage. After fitting the production history, the EUR of the Z2-H1 well is estimated to be 54 million cubic meters. At the same time, based on the actual geological and engineering parameters of the work area, an integrated geological and engineering model was established. After fitting the production history, the EUR of the Z2-H1 well is calculated to be 64 million cubic meters. To summarize, the predicted EUR of the Z2-H1 well is 49 to 64 million cubic meters.

4. Optimization Strategies to Increase Production

4.1. New Drilling Technology. The pendulum assembly is mainly used above the inclination section of the Z2-H1 well,

and both single and multipoint inclination measurements are used on the trajectory monitoring to meet the well inclination control. With the rotary guidance tool used for monitoring both inclination and horizontal sections, as well as MDW/LWD (horizontal section) technologies, the dogleg can be well controlled and a higher drilling efficiency can be ensured. The drilling rate is improved with the imported PDC and screw composite drilling assembly, four spud drilling pressure of 70–140 kN, the pumping rate of 26–30 L/s, the rotational rate of 75–100, the 50 rpm screw pipe, and the pump pressure of 25–32 MPa. The single drilling bit has a drilling footage of 313 meters and an average mechanical drilling rate of 3.97 meters per hour.

The drill bit, some speed-increasing tools, and drilling parameters need to be optimized, so that some problems can be solved, such as long and large-sized wellbore in deep wells, which increase formation compaction, worse

drillability, bad formations, and slow mechanical drilling rate. For some complicated geological conditions, the risks of downhole accidents such as circulation loss, overflowing, and jamming of drilling tools are very high. On the basis of precaution, by reinforcing wellbore cleaning, precise pressure control, and optimizing the plugging of drilling fluid, the chance of downhole accidents can be reduced. A better casing is selected to reduce the risk of casing deformation, save the cost, and ensure the wellbore integrity at the same time, through the contrast test between a 140 SG grade steel (anti-extrusion of 178.4 MPa) casing with 139.7 mm outer diameter and 12.7 mm wall thickness and a 125 SG grade steel (antiextrusion of 182 MPa) casing with 139.7 mm outer diameter and 15.2 mm wall thickness.

4.2. Pathway Optimization. The thickness of type I reservoir of Wufeng formation is large, with the maximum thickness of 6.7 m. The combination production of layer $S_1L_1^{1-1}$ and $S_1L_1^{1-3}$ of Wufeng formation is 49,000 m³/d, showing high productivity potential. At the same time, the production logging results of the Z2-H1 well show that the fracturing stages of Wufeng formation also have a large gas production contribution. From the perspective of the gas production per meter of each sublayer, Wufeng formation and $S_1L_1^{1-1}$ have the gas production of 40.9 m³ and 44.8 m³, respectively, which are basically equivalent. Moreover, the Wufeng group shows better potential. Therefore, it is necessary to select the pilot test in which the target position of the pathway is in Wufeng formation, to evaluate the horizontal well productivity of different target positions, and finally to confirm the optimal target position. Taking the TOC (total organic carbon), gas content, physical properties, brittle mineral content, and other indexes into consideration, the best layer of the type I reservoir was chosen as the tested position of the horizontal well pathway. The overall reservoir parameters of the upper Wufeng formation are better than the middle and lower Wufeng formation. Therefore, the upper Wufeng formation was selected as the pathway position for the pilot test, which is 3.8–6.8 m away from the bottom of Wufeng formation.

4.3. Optimization of Horizontal Pathway Spacing. Based on the actual high-resolution 3D geomechanical model of the Z2 well, three virtual horizontal wells with different well spacings of 300 m, 350 m, and 400 m were established. The trajectory orientation, drilling efficiency of each sublayer, and the length of the horizontal section are consistent with the Z2-H1 well. The well interference under different pathway spacings was simulated through the integrated geological and engineering model. The fracturing simulation parameters refer to the actual operation parameters, with the 1,500 m length of horizontal section, 29 fracturing stages, 50 m length of each stage, 3 perforated clusters each stage, 40 m³/m liquid strength, 2.2 t/m sanding strength, 14 m³/min pumping rate, slug sanding, and zipper fracturing. The simulation results of the fracture network of two wells with zipper fracturing show that the larger the well spacing under high stress (20 MPa), the longer the length of hydraulic fracture, the easier it is to produce simple frac-

tures. When the well spacing is 300 m, the fracture spacing is too small and the well interference is too strong, so that the stimulation volume is small. The hydraulic fracture is the most complex under the 350 m well spacing.

Based on a complex network formed by the hydraulic fracturing, a nonstructural numerical simulation model was established to predict the productivity after fracturing, and the flowing pressure at wellbore bottom is limited to 10 MPa. Production under different well spacings is simulated and compared. The results show that EUR of a single well is the highest under 350 m well spacing, while the 400 m well spacing is the second and the 300 m well spacing is the lowest (Figure 7). The pressure distribution under different well spacings shows that the effective producing ranges of 300 m and 400 m well spacing are smaller than that of the 350 m well spacing. In order to further study the well interference and EUR under different well spacings, pilot tests are needed to provide guidance for the deployment of well locations in the future development.

4.4. Optimization of Horizontal Section Length. According to the investigation, the EUR of gas wells rises gradually with the increasing length of the horizontal section, as calculated in Table 2. However, when the length of the horizontal section reaches the maximum, EUR increases within a limited range if the length of the horizontal segment continues to increase. At the mean time, as the length of horizontal section increases, the cost of a single well also improves. So the optimization of the horizontal section length must take economic benefit into account. The simulation results of an integrated geological and engineering model and calculation results of economic limit production show that only gas wells with the horizontal section length of 2,000 meters can realize economic development, and the single-well EUR has to be more than 154 million cubic meters. Therefore, two horizontal wells with the length of 2000 m can be designed for the pilot test to evaluate the productivity of the long horizontal wells in the northern and southern parts of the Z2 well.

4.5. New Fracturing Technology. In order to enhance the drainage area and complex fractures, the model of large liquid volume, large amount of sand, low viscosity, small particle size, and low proppant concentration were taken for the fracturing technology with the characteristics of deep and high closure stress in this field. The main pumping method of the well is slug pumping with low-viscosity slick water and ceramic sand, which help to improve the formation of complex fractures. The comparison and simulation results of the well performance have shown that the gel as pad fluid for fracturing+slick water fluid for proppant carrying mode for natural fractures can effectively avoid the problems of microfracture development near wellbore and sand carrying, due to the development of natural fractures, as shown in Figures 8(a) and 8(d)). The Z2-H1 well has a large depth; the dense fractures+high-strength sanding process is tested for the complexity of fractures. The general segmental length of the shale gas well is about 60 m, but the length of this stage is shortened to 51.5 m. It can increase the number of

FIGURE 7: Cumulative gas production curve for the Z2-H1 well under different well spacing conditions.

fractures in the horizontal well section and improve the hydraulic fracturing strength for the horizontal section. During the fracturing process, the well is sensitive to 160 kg/m^3 sanding strength and has a large fluctuation of pressure, reflecting the general phenomenon that the width of the hydraulic fracture of deep shale gas wells is narrow. For the typical fracturing stage in the Z2-H1 well, the pumping rate was maintained at $15 \text{ m}^3/\text{min}$. The pumping pressure was 77–80 MPa. The proppant rate was $120\text{--}140 \text{ kg/m}^3$ for a major period, followed by 160 kg/m^3 high concentrations as tail slug to support the opening of the fracture (Figure 8(b)). Simultaneously, in the naturally developed fracture stage, a certain amount of the temporary plugging agent was added at the 50% length of the single-stage liquid volume to further improve the uniformity of the reservoir stimulation in the horizontal stage. The microseismic interpretation of SRV indicates that in the temporary plugging agent filling stage, the average single-stage SRV increased by 19.5% compared to the unfilled segment (Figure 8(c)).

At present, the fracturing process of deep shale gas wells is still evolving. The parameters such as stage length, pumping rate, operational scale, and perforation mode still need to

be further optimized. We have still been facing a series of problems, e.g., deep burial depth, long horizontal section, up-dip, and dog-legged wells deployed in the later stage, and coiled tubing operation. The next step is to consider using a sleeve and sliding sleeve+soluble bridge plug combination. A new method for effective segmentation is expected for deep long horizontal sections. This can reduce downhole operation workload and ensure drainage continuity. The 40/70 mesh ceramic proppant body is mainly used at present, and the particle size range is generally between 0.224 and 0.45 mm. Under the high closing stress condition of 80 MPa or higher, the proppant embedding phenomenon is prominent. The embedding depth is between 0.05 and 1.0 mm, and the breaking rate of proppant is high. The combination modes for proppant with different particle sizes should be explored to reduce the influence of the proppant embedding on the permeability. In the naturally developed fracture stage the stress difference is large, and the effect of the temporary blocking and diversion process is minor. Therefore, it needs to further optimize the parameters such as the timing and concentration of the temporary blocking ball and the temporary plugging agent to ensure the uniform

TABLE 2: Economic limit production data sheet.

Parameters	Ground investment (10^4 yuan/well)	Subsidy (yuan/ 10^3m^3)	Internal rate of return (%)	Operating cost (yuan/ 10^3m^3)	Horizontal section length (m)	Drilling and completion investment (10^4 yuan/well)	EUR (10^8m^3)	Prediction EUR (10^8m^3)
Value	2500 for external and internal input	200 in 2020	8	Annual average of 220	1500	7000	1.49	1.03
					1800	7885	1.64	1.38
					2000	8475	1.73	1.62
	1300 for internal input	200 in 2020	8	Annual average of 220	1500	7000	1.31	1.03
					1800	7885	1.45	1.38
					2000	8475	1.54	1.62

FIGURE 8: Effective charts of implementing new technologies during fracturing process.

FIGURE 9: Production and pressure with different sizes of nozzles.

stimulation of horizontal stage. It is necessary to carry out a series of tests in deep formations and to determine the optimal parameter template for fracturing technology in this area, which helps to achieve highly efficient and scaled development for deep shale gas wells.

4.6. Optimization of Production System. The key to the optimization of the production system is to maximize production through flexible nozzle adjustment. The effects of rock stress, fracture closure pressure, and the influence of pressure differential on proppant flow back should be considered comprehensively. Appropriate nozzles should also be formulated according to different completion designs. If the fracture closure pressure is very high and exceeds the range of proppant breakdown pressure, effective stress would act on the proppant layer, and the proppant would break, which will damage the fracture conductivity. At the same time, the compressed fracture space restricts the gas flow channel and increases the linear velocity of the gas flow, so that the broken/unbroken proppant is discharged from the fracture under the influence of the gas flow, which leads the fracture to lose support from the proppant. The coupling of the two effects would have a huge impact on the EUR of shale gas.

As researchers continue to study and understand the reservoir lithology and the characteristics of fracture closure after fracturing, and the continuous optimization of well completion quality, the shale gas well production system is constantly optimized from the earliest casing flow to the flexible use of nozzles to control production in the later period. Wells can be opened based on the adjacent wells and preestablished production/pressure standard specifications. The optimization of the production system has gradually transitions from production control to pressure control. By flexibly controlling the nozzles, the production with small nozzles has a low production initially, and it is stable and decreasing slowly (Figure 9). However, when the nozzle is changed from 5 mm to 7 mm, the initial production is very high, but it declines very fast. Besides, the cumulative gas

production is high, the formation energy is maintained, and the single-well EUR is increased. At the same time, the gas production process needs to be formulated, including early placing of production tubing, plunger gas lifting, foam drainage, and gas lifting. These methods would cooperate with the production system to maintain wellhead pressure, delay decline in production, reduce fluid accumulation at the bottom of the well, and improve gas well stable production with fluid. Finally, gas well productivity would be maintained effectively and production would be maximized. Therefore, reasonable production system and gas production process measures can bring higher EUR and higher yields for shale gas wells.

5. Conclusion

- (1) The quality of the shale gas reservoir of the Wufeng formation-Longmaxi L_1 sublayer is good. The Wufeng shale formation is thick, which can be selected as the horizontal well pathway. Natural fractures are relatively developed. The horizontal well pathway should be paralleled to the direction of minimum horizontal stress. The horizontal well trajectory orientation should have a certain angle with the minimum principal stress direction, which is a benefit for the complexity of fracture networks
- (2) Deep wells have large boreholes with long wellbore, strong formation compactness, and poor drillability. Selection of drilling bits and speed-up tools is difficult, and the drilling rate is slow. The fractures and bedding in Longmaxi formation are rich. The safety density window for drilling is narrow; thus, the risk of overflow and lost circulation is high. The wellbore in the horizontal stage of the deep well is difficult to clean, and the friction torque is large. Therefore, it is difficult to extend the horizontal section length. Therefore, the new drilling technology can be tested

to improve drilling efficiency in high-quality reservoirs

- (3) The shale gas well has a rapid decline on gas production but a large water production. The overall production is not good, mainly due to the fracture complexity not being sufficient, resulting in the relatively simple distribution of a large fracture system. In addition, the overall SRV for fractures is limited, and thus, a new fracturing technology is expected to improve the fracture complexity
- (4) Measures with a reasonable production system, such as proper nozzle size and gas production process, can bring higher production and higher EUR for shale gas wells
- (5) Preliminary pilot tests with a systematical design should be executed in the target area. A reasonable deployment for pilot test wells and clear development of technical policies are required. This provides fundamental knowledge for improvement in well production and follow-up development plans for deep shale gas wells

Data Availability

All data used in this study can be obtained by contacting the corresponding author (Wuguang Li), through email address: liwuguang@petrochina.com.cn.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

Authors' Contributions

Wuguang Li and Hong Yue are joint first authors.

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