Large-Scale Network Fracturing Practice in Deep Coal Seam in Eastern Ordos Basin

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Abstract. No.8 coal seam of Benxi Formation in Shenmu-Jiaxian Block in eastern Ordos Basin are characterized by tight, low permeability and developed beddings and cleats, fracturing is required to increase single well production. However, field practice proved that conventional vertical well fracturing has no economic benefits [1–3]. Based on previous research and field constructions, a study aims to build a large, dense and fully supported volumetric fracture network for No.8 coal seams was carried out. Fracability evaluation of deep coal seam was first studied. No.8# coal seam has good coal body structure, developed fractures and cleats, high gas content, lithology of top roof and bottom floor are mudstone, which has good foundations of building large-scale fracture network through fracturing. Then geo-engineering dessert evaluation criteria was established, and key fracturing technologies including staged fracturing, differentiated slug injection and fracture-expansion by varing injection rate and fluid viscosity, highly efficient proppant-filling technology were formed and applied in the filed fracturing construction of JH1 in Ordos Basin. The success of JH1 is a great breakthrough in deep coal seam gas fracturing technology, which provide reference and technical guidance for the exploration and development of similar reservoirs.

Keywords: coal seam gas fracturing · large-scale complex fracture networks · filtration loss control · efficient proppant filling · fully supported

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1 Introduction

Coal seam gas (also coal bed methane or CBM) resources in China have great potential. At present, the exploration and development of CBM are mainly in Qinshui in the eastern margin of Ordos Basin, Junlian in Sichuan Province, Jungalangtu in Inner Mongolia, Fukang in Xinjiang etc. The coal seam burial depth less than 2,000 m defined as shallow coal seam gas, with a resource of 29.82 trillion square meters. Burial depth between 2,000–3000 m defined as deep coal seam gas with 18.4 trillion square meters resource. As a kind of self-generated and self- stored unconventional reservoir, the matrix permeability of coal seam is generally low (less than 1mD). Most of the coalbed methane that stored in coal seam are in adsorption state, only when the reservoir pressure is reduced can the gas be desorbed and extracted [4–6]. Therefore, fracturing plays an important role in CBM development. Moreover, there is a positive correlation between single well production and the volume of fracture network constructed by fracturing. The adsorbed gas as well as the free gas distributed in coal pores and fractures are more likely to be produced by larger and complex fracture network. However, the stimulation effect of vertical well is limited. In order to achieve higher production, it is necessary to carry out the research and practice of horizontal well large-scale network fracturing technology [7–10].

The research on complex fracture network construction technology of horizontal well fracturing for No.8 coal seam of Benxi Formation in Shenmu-Jiaxian block in the eastern margin of Ordos Basin is systematically described in this article. Through the research, the evaluation criteria of geological engineering sweet spot for deep coal seam is established, fracturing design concept is clarified, and the key fracturing technology of constructing complex fracture network is formed. The research results are applied to JH1 fracturing construction, which has provided reference for deep coal seam horizontal well fracturing treatments in other regions and similar reservoirs.

2 Regional Profile and Reservoir Characteristics

Shenmu-jiaxian block is located in the northeast of Yishan Slope of Ordos Basin, belonging to Weibei Uplift and Jinxi fold belt. There are 11 sets of coal seams developed in this area, buried depth ranged from 1800 m to 2400 m, with a total hydrocarbon generation of 7.6 trillion cubic meters. Among the 11 sets, No. 8 coal seam of Benxi Formation distributed most stably with a total hydrocarbon generation of 3.2 trillion cubic meters, accounting for 42% of the total hydrocarbon generation of all 11 sets of coal seams. Therefore, No. 8 coal seam has the great development potential.

2.1 Geological Features

Structural Feature. The whole area is a wide and gentle west sloping with a slope of 6–10 m/km and a dip angle of 0.3–0.6°. As shown in Fig. 1, structural features are simple, faults are not developed in this area, which is beneficial to the accumulation and preservation of natural gas.

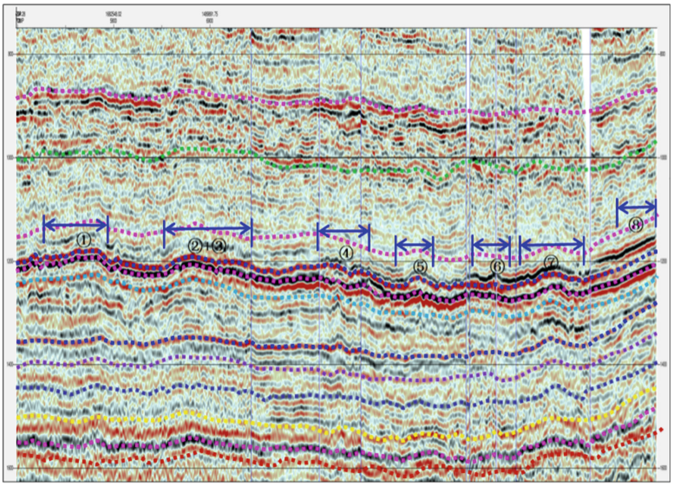

Fig. 1. North-south seismic profile of the survey area

Coal Thickness and Burial Depth. No. 8 coal seam of Benxi Formation is stably distributed in this area, buried from 1700 to 2500 m, with an average buried depth of 2260 m (shown in Fig. 2). Coal thickness varied from 4–20 m, average thickness is 9.4 m.

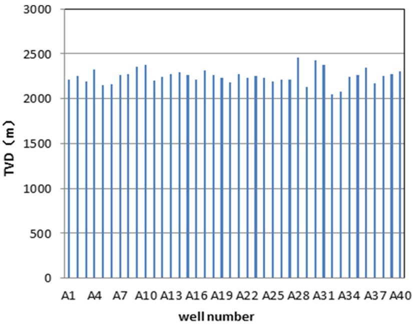

Fig. 2. Histogram of the burial depth of coal seam No.8

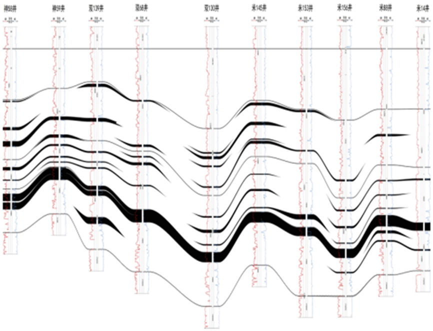

Fig. 3. Stratigraphic comparison map of the survey area

Microstructure Characteristics of Coal Bed. The most critical factors that we normally used to describe microstructure characteristics of coal bed are coal body structure and cleating, since these factors are tend to affects gas production and development potential. From longitudinal observation, coal body structure from top to bottom has demonstrated as primary -cataclastic - crushed inside No.8 coal seam. At the same time, No.8 coal seam in the whole area changes rapidly laterally, mainly primary coal and cataclastic coal, and a small amount of crushed coal in area distribution (Figs. 3, 4 and 5).

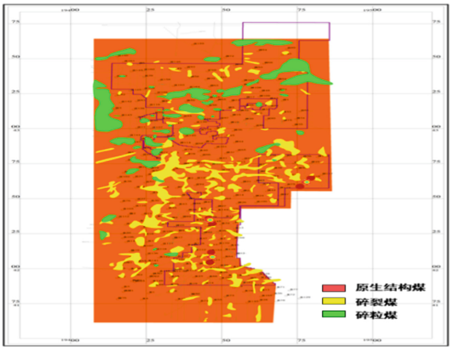

Fig. 4. Coal structure distribution map

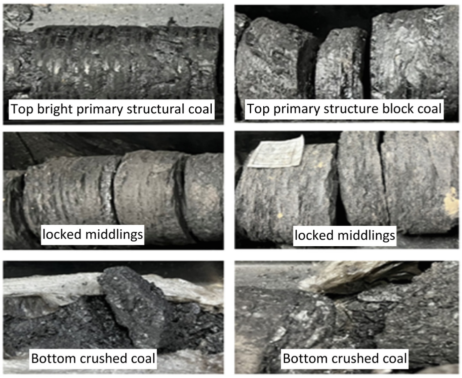

Fig. 5. Coal seam core observation

Gas-Bearing Nature. Gas -bearing nature of coal seam is the most important foundation on prospecting and exploitation decision of coal seam gas. In Shenmu-Jiaxian block, the measured gas content per ton is between 16–22 m^3/t. Besides, there are 47 CBM wells (accounting for 67% of the total number of pre-exploration wells) with total hydrocarbon peak value greater than 60%, also confirmed that gas content of the block is relatively high (Figs. 6 and 7).

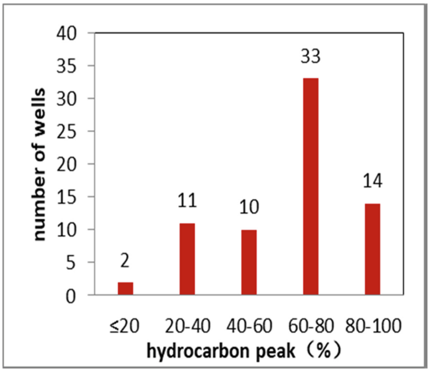

Fig. 6. Total hydrocarbon peak histogram of coal seam No.8

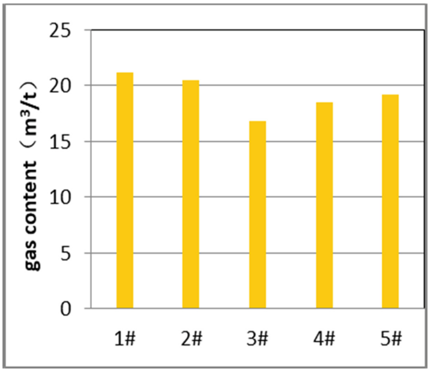

Fig. 7. Gas content test histogram of coal seam No.8

2.2 Engineering Features

Reservoir Properties (Related to Fracturing). No. 8 coal seam can be defined as ultra-low porosity and permeability reservoir, with an average porosity of 3.78% and average permeability of 0.026 mD, which needs to be fractured to achieve economic exploitation (Figs. 8 and 9).

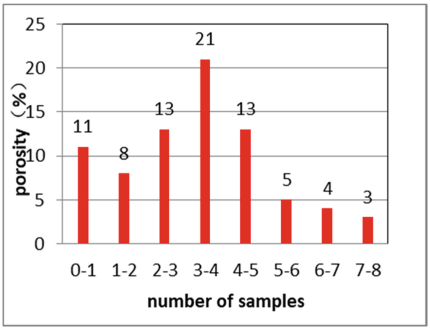

Fig. 8. Histogram of porosity distribution of No.8 coal seam

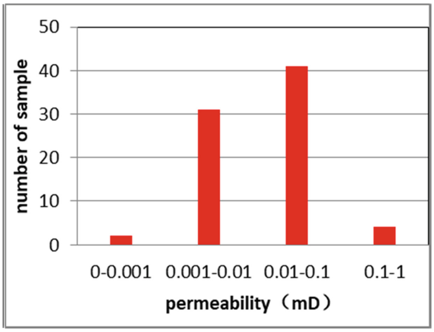

Fig. 9. Histogram of permeability distribution of No.8 coal seam

Characteristics of Reservoir Fracture Development. Fractures and cleats development are essential to the construction of complex fracture network systems. The natural fractures and cleats are developed in No. 8 coal seam of Benxi Formation. The linear density of cleats is 7–36/5 cm, with an average of 18/5 cm. On the core section of coal seam, the cleats distributed linearly and fracture network distributed continuously, which is beneficial to gas production. However, the development of fractures also have negative effects such as the loss of fracturing fluid, resulting in low fluid efficiency. Therefore, appropriate fluid filtration control measures should be taken to improve fracturing efficiency and fracture sweep volume (Figs. 10 and 11).

Fig. 10. Coal core section of No.8 coal seam

Fig. 11. Fracture distribution of core sample

Roof and Bottom Floor Characteristics. The top roof and bottom floor of No.8 coal seam are all mudstone, with an average thickness of 11.8 m and average stress difference of 10.7 MPa. The barrier condition of roof and floor are good, which is conducive to fracture height control and ensured a good foundation of large-scale volume fracturing.

Reservoir Rock Mechanics. Rock mechanical parameters of No.8 coal seam were tested in lab and the test result is demonstrated in Table 1–2. Compression experiment results confirmed the Young's modulus of coal seam is around 4–5GPa, and Poisson's

Table 1. Conditions of roof and floor of No.8 coal seam

Well	Top Roof			Bottom Floor		
	Lithology	Thickness (m)	Stress difference(Mpa)	Lithology	Thickness (m)	Stress difference (Mpa)
A1	mudstone	13	8.9	mudstone	11	8.4
A2	mudstone	16	9.2	mudstone	6.5	13.1
A3	mudstone	9.8	10.8	mudstone	17.3	11.7
A4	mudstone	8.7	9.7	mudstone	11.1	9.4
Range	/	8.7–16.0	8.9–10.8	/	6.5–17.3	8.4–13.1
Average	/	11.9	9.7	/	11.5	10.7

ratio is as high as 0.33–0.46. The low Young's modulus and high Poisson's ratio indicating that the plasticity of No.8 coal seam is strong. The main challenge of plastic reservoir fracturing is proppants insertion damage, which would have a negative impact on fracture conductivity. Therefore, in order to maintain fracture conductivity, effective measures should be taken to avoid or reduce the insertion damage.

Table 2. Rock mechanical parameters of No.8 coal seam

Sample	Well	TVD(m)	Lithology	Pressure(MPa)	Young's modulus (GPa)	Poisson's ratio	Shear modulus(GPa)	Bulk modulus(GPa)
1	B11	2226.1	Top Roof	20	20.14	0.209	8.33	11.54
2		2226.93		20	24.39	0.246	9.79	16
3		2227.42	Coal Seam	20	4.86	0.336	1.82	4.93
4		2228.13		20	5.83	0.293	2.26	4.7
5		2228.91	mudstone	20	12.1	0.184	5.11	6.38
6		2229.85	Coal Seam	20	5.72	0.309	2.18	4.99
7		2230.95		20	7.3	0.465	2.49	34.76
8	B12	2304.46	Top Roof	20	21.52	0.235	8.71	13.53
9		2306.76	Coal Seam	20	4.96	0.28	1.94	3.76
10	B13	2087.64		20	3.59	0.27	1.41	2.63
11		2084.98	mudstone	20	7.79	0.17	3.34	3.91

2.3 Geological-Engineering Sweet Spot Evaluation

By analysis the factors that affect gas enrichment and production mechanism of deep coalbed methane in No.8 coal seam of Benxi Formation in our exploration area, the evaluation criteria for the geological-engineering sweet spot was formed, including microstructure, coal seam thickness, gas content, coal body structure, roof and bottom floor conditions, compressibility and other key parameters [11–13]. The criteria is demonstrate in Table 3. Normally, coal seam burial depth less than 2000 m, thickness higher than 8 m, measured gas content per ton higher than 16 m^3/t can be defined as geological dessert. Primary coal with developed natural fractures and cleats, brittleness index higher than 50, top and bottom roof thickness higher than 8 m and stress difference higher than 6 MPa can be defined as engineering dessert.

Table 3. Geological engineering dessert evaluation criteria of No.8 coal seam

Geological Sweet Spot			Engineering Sweet Spot		
Index	I	II	Index	I	II
Structure	Dip angle < 3°	Dip angle > 3°	Coal Body Structure	Primary coal	Primary-cataclastic coal
Coal Seam Thickness (m)	> 8	< 8	Natural Fractures and Cleats	developed	not developed
TVD (m)	> 2000	1500–2000	Brittleness Index	> 50	< 50
Gas Content (m3/t)	> 16	< 16	Top and Bottom Floor Thickness (m)	> 8	< 8
Hydrocarbon Peak	> 60	< 60	Stress difference (Mpa)	> 6	< 6

Table 4. Proppant conductivity with different particle sizes and different combination ratio

Proppant Combination	Proppant conductivity under different stress (μm^2 cm)		
	10 MPa	20 MPa	30 MPa
70/140 mesh fine sand	8.5	6.4	3.8
40/70 mesh sand	13.7	8.6	5.9
70/140 sand + 40/70 sand + 30/50 ceramite (3:6:1)	23.4	18.5	10.5

Table 5. Fracturing pumping procedures of JH1

Pumping stage	Injection Rate	Fluid Type	Fluid Volume	Accumulated Fluid Volume	Sand liquid ratio	Sand Volume	Accumulated Sand Volume	Proppant Size	time
	m3/min		m3	m3	%	m3	m3		min
Pre-fluid 380m3	1–12	high viscous	30	30					5
	12–14	high viscous	60	90					4.3
	12–14	medium viscous	40	130	6	2.4	2.4	70/140 mesh sand	2.9
	14–16	low viscous	60	190			0		4.3
	14–16	medium viscous	40	230	7	2.8	5.2	70/140 mesh sand	2.5
	16–18	low viscous	60	290			0		3.8
	16–18	medium viscous	40	330	8	3.2	8.4	70/140 mesh sand	2.2
	18–20	medium viscous	50	380			0		2.8
Sand carrier 2150m3	18–20	medium viscous	170	550	8	13.6	22	70/140 mesh sand	9.4
	18–20	medium viscous	200	750	10	20	42	70/140 mesh sand	11.1
	18–20	medium viscous	230	980	12	27.6	69.6	70/140 mesh sand	12.8
	18–20	medium viscous	250	1230	14	35	104.6	70/140 mesh sand	13.9
	18–20	medium viscous	270	1500	16	43.2	147.8	70/140 mesh sand	15.0

(*continued*)

Table 5. (*continued*)

Pumping stage	Injection Rate	Fluid Type	Fluid Volume	Accumulated Fluid Volume	Sand liquid ratio	Sand Volume	Accumulated Sand Volume	Proppant Size	time
	m3/min		m3	m3	%	m3	m3		min
	18–20	medium viscous	260	1760	18	46.8	194.6	70/140 mesh sand	14.4
	18–20	medium viscous	230	1990	22	50.6	245.2	70/140 mesh sand	12.8
	18–20	medium viscous	200	2190	24	48	293.2	40/70 mesh sand	11.1
	18–20	medium viscous	180	2370	26	46.8	340	40/70 mesh sand	10.0
	18–20	medium viscous	160	2530	28	44.8	384.8	30/50 ceramite	8.9
	16–18	low viscous	51	2581					2.8
total			2581			384.8			150.0

3 Large-Scale Network Fracturing Technology

Based on the preliminary study and analysis of reservoir characteristics, it is clear that the No. 8 coal seam of Benxi formation in the exploration area has good coal structure, developed fractures and cleats, which are good foundations of building large-scale fracture network through fracturing. Therefore, fracturing design was carried out and key parameters were optimized in order to achieve high gas production.

3.1 Horizontal Well Fracturing Stage and Cluster Design

Horizontal well staged fracturing of coal seam has gradually become an important method to increase CBM production in recent years. Compared to vertical wells, horizontal wells have larger contact area with coal seam, which is more beneficial to increase the seepage channel of coal-bed methane. Furthermore, hydraulic fracturing can form a more perfect fracture system, so as to effectively expand the reconstruction volume of coal seam and improve gas production [14, 15]. The parameters of stage and cluster design were evaluated in this part.

Well Path. According to the array acoustic logging and electro-imaging logging data in the study area, the measured crustal stress direction is NE 80°–90°. Considering that fractures are more inclined to extend along the direction of maximum horizontal principal stress, it is advisable to drill the well path along the north-south direction.

Stage and Cluster Design. There are two main principles of stage and cluster design: first is to determine the reasonable stage spacing to maximize the reconstruction length of horizontal section. Second is to avoid fracture interference and determine perforation location. Numerical simulation, fracture monitoring results and previous production data were analyzed to design stage and cluster spacing. According to previous fracture monitoring results, the reservoir stimulation width is about 70–110 m. Besides, numerical simulation results certificated that between 20–25 m cluster spacing fractures extended sufficiently without fracture interference. Therefore, the interval between stages is determined to be 80–90 m, each stage has 3–4 clusters, with a cluster spacing of 20–25 m (Fig. 12).

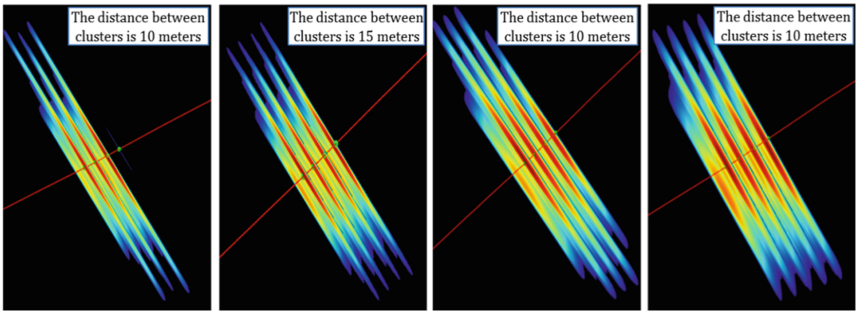

Fig. 12. Fracture propagation morphology at different cluster spacing

Selection of Perforating Location. Perforate in high quality coal seam with good coal body structure can facilitate fractures initiation and extension, thus to improve the effect of reservoir reconstruction. GR value, cementing quality and coal seam location are the key factors that determine coal seam quality and stimulation effect.

There are three main principles for the selection of perforation location: (1) High GR value normally stand for high mud content and poor coal seam purity. Therefore, combined with the GR value characteristics of No. 8 coal seam as well as mudstone in the study area, the GR value of perforating perforation is required to be less than 80API. (2) Select a position with good cementing quality to reduce the risk of fracturing pipe channeling. (3) The upper part of No. 8 coal seam in study area has better coal body structure and high proportion of primary structure coal, therefore perforation location can be better selected in the well trajectory where the drilling path located in the upper part of No. 8 coal seam to reduce the influence of coal powder migration during drainage.

3.2 Pumping Schedule Design

Pumping schedule can affect the scale and geometry of fracture network. In order to build large-scaled and complex fracture network, factors affecting fracturing design such as fracturing fluid viscosity, construction rate and injection volume need to be taken into consideration, to ensure the main fracture penetrated deeply, the secondary fractures fully extended, and micro-fractures dilated at the same time [16, 17].

Fluid Filtration Control. Due to the development of natural fractures and cleats in No. 8 coal seam, fluid loss caused low fluid efficiency is one of the main difficulties. When shear fracture occurs at the intersection of hydraulic fracture and natural fracture, T-shaped fracture might formed, which would have negative effects of artificial main fracture extension. Therefore, to build a large-scaled complex fracture network with developed long main fracture, communicated branch fractures and fully opened natural fractures, an alternating fracturing fluid injection process is proposed. Fracturing fluids with different viscosities that injected into the formation have different functions. First of all, high viscosity fluid is pumped in the early stage, since high viscosity fluid is not able to penetrate into natural fractures. This process can be helpful to reduce fluid loss so more fluid can be contribute to improve main facture expansion. Secondly, low viscosity in the middle stage can help to communicate natural fractures and medium viscosity fluid in the late stage used for network construction (Figs. 13 and 14).

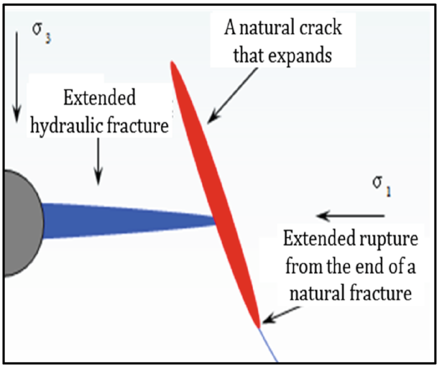

Fig. 13. Schematic diagram of fracture extension

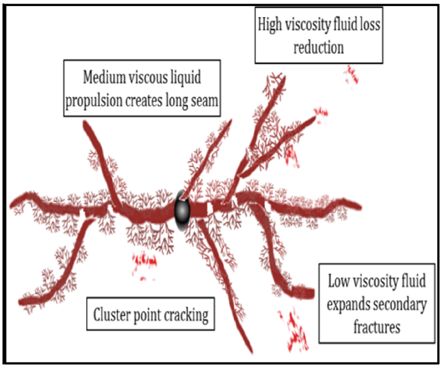

Fig. 14. Schematic diagram of complex network

Injection Rate Design. Numerical simulation shows that increasing injection rate can effectively promote fracture extension forwardly. When the injection rate is higher than 18 m3/min, the opening degree of bedding joints can be effectively improved, which is conducive to the construction of a more complex fracture network system. However, pumping rate rise to 18 m^3/min within a very short time will greatly increase the risk of longitudinal fracture penetration and result in uncontrolled fracture height. Therefore, it is determined that pumping rate is set to be low at first (normally 3–5 m^3/min) and increased step by step to 18 m^3/min (Figs. 15 and 16).

3.3 Efficient Filling of Fracture Network

Proppant Selection. Different proppant sizes are required to realize efficient filling of the complex fracture network. Proppant was selected under the principle of micro-fractures supported by silt proppants in the early stage, main fractures supported by fine sand in the middle stage, ceramsites are used to support fractures near the well in the late

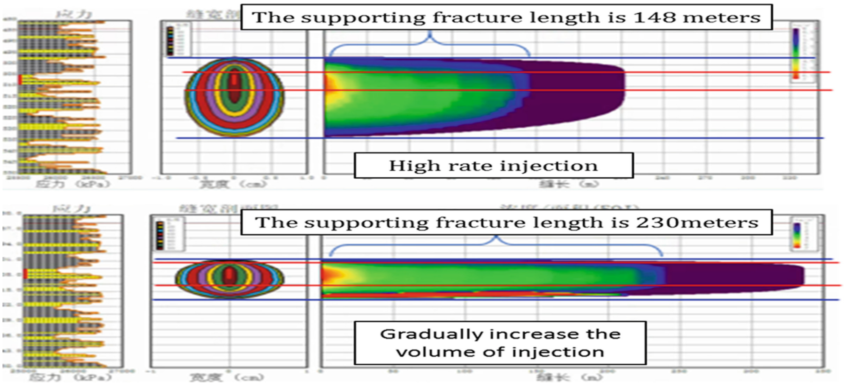

Fig. 15. .Comparison of fracture morphology at different injection rates

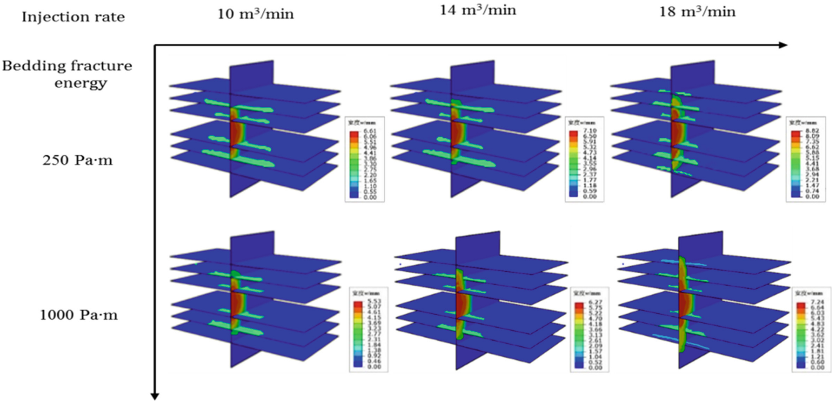

Fig. 16. Opening of laminated seams at different injection rates

stage to ensure conductivity [18]. Moreover, the pressure acting on proppants in No.8 coal seam was calculated by formula $P_a = \sigma_c - P_{wf}$, where P_a= the stress acting on proppant, MPa; σ_c= fracture closure pressure, MPa; P_{wf}= bottom hole flow pressure, MPa. According to the formula, the pressure acting on proppants in No.8 coal seam in our study are is between 22 and 27.4 MPa. Due to economic reasons, considering the cost of quartz sand and ceramite, the combination usage of quartz sand and ceramite can reduce the cost to a certain degree. Meanwhile, laboratory experiment results confirmed that 70/140 quartz sand + 40/70 quartz sand + 30/50 mesh ceramite combined in a ratio of 3:6:1 can maintained a fracture conductivity of 10 $\mu m^{\wedge 2}$·cm under a closing pressure of 28 MPa, which can meet construction requirements. Therefore, proppant type and combination ratio were determined and the experiment result is demonstrate in Table4.

Proppant Concentration. As proppant embedment damage is serious in coal seams which are low in Young's modulus and high Poisson's ratio, fracture conductivity is limited to a certain degree. In order to ensure fracturing results, it is needed to maintain fracture network conductivity [19, 20]. Measurements were taken when designing pumping schedules include: (1) Control the proportion of pre-liquid ($\leq$15%); (2) Control the overall sand to liquid ratio ($\geq$13%); (3) Improve the sand ratio continuously, average sand ratio $\geq$ 16%, the highest sand ratio $\geq$ 25%; (4) Sand concentration $\geq$ 6.5 t/m.

4 Field Practice

JH1 is a horizontal well in Shenmu-Jiaxian Block in eastern Ordos Basin, the target reservoir is No. 8 deep coal seam of Benxi formation. The burial depth is 2200 m, reservoir thickness is 6–7m and Ro value of coal seam is 0.7–1.6%, the coal body structure is mainly primary -cataclastic structure from top to bottom inside No.8 coal seam. The designing goal is to build complex fracture network system with large scale and high conductivity, and to improve fracture-controlled reserves and to achieve high gas production. Pumping schedule shown in Table 5 is optimized based on the research results in this paper.

Field fracturing construction of JH1 has achieved great success. The horizontal section of JH1 was 1760 m long, and fractured with 61 clusters in 20 stages. 499,34 m^3 fracturing fluid and 7119 m^3 proppant were pumped into the reservoir. All fracturing indexes have reached domestic advanced level: pre-fluid ratio of 12.5%, the average sand ratio of 16.9% and the sand liquid ratio of 14.2%. The average construction rate was 20.9 m^3/min, and the maximum construction rate reached 25.9 m^3/min. JH1 has achieved high gas production after fracturing, which has proved the effectiveness of the fracturing technology we proposed in this study (Fig. 17).

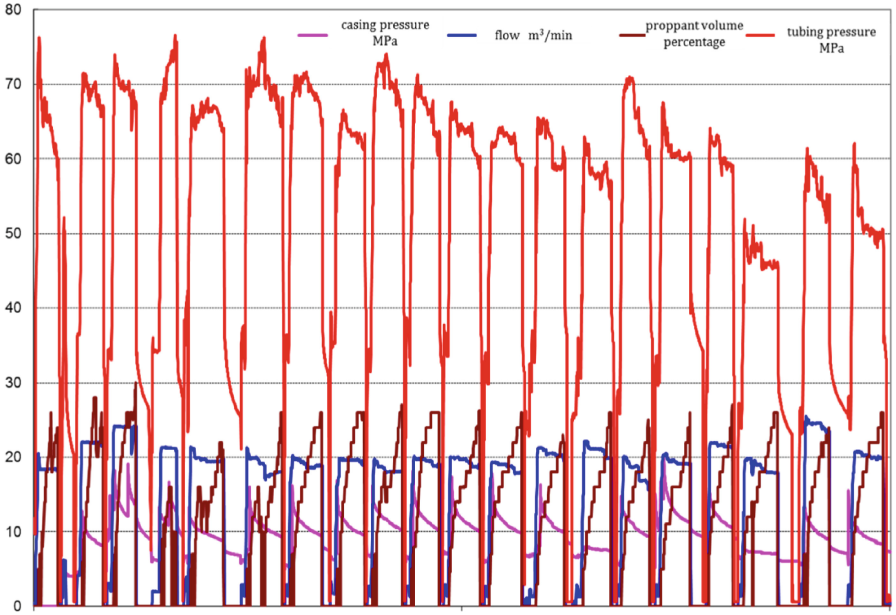

Fig. 17. Fracturing construction curve of JH1

JH1 achieved high gas production after fracturing for the first two months with an average gas production of 9 × $10^4 m^3$ per day, and wellhead pressure of 7–8MPa. Compared with the previous 0.3–0.5 × $10^4 m^3$ /d gas production of vertical wells, JH1 represented an important breakthrough of deep CBM development. After four months of production, the daily gas production stabilized at 3.5 × $10^4 m^3$/d, and the wellhead pressure of 4–5 MPa. At present, JH1 has produced stably for over 200days, and the cumulative gas production has been 1260 × $10^4 m^3$, which proves the effectiveness of the fracturing technology proposed in this study (Fig. 18).

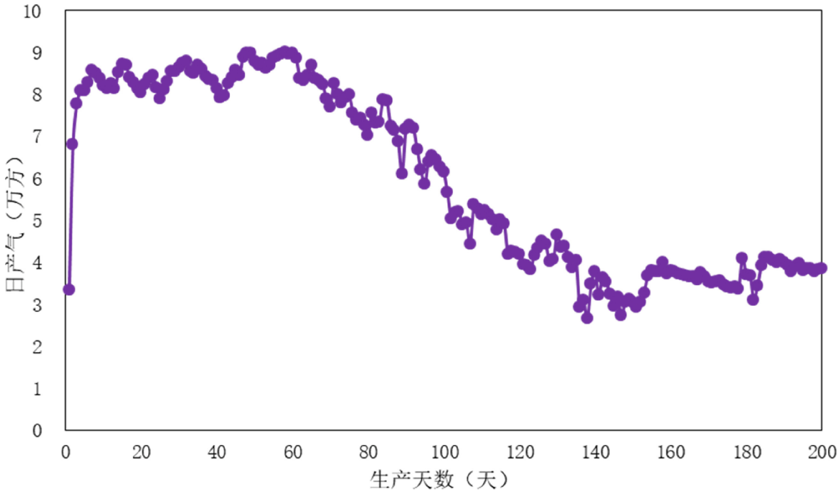

Fig. 18. Production curve of JH1

5 Conclusion and Suggestion

1. No.8 coal seam of Benxi formation in Shenmu-Jiaxian Block in eastern Ordos Basin has good coal body structure, developed fractures and cleats, high gas content, mudstone top roof and bottom floor, which has good foundations of building large-scale fracture network through fracturing.
2. Key fracturing technologies such as staged fracturing, differentiated slug injection and highly efficient proppant filling technology can be used to ensure fracture network building and thus increase single well production.
3. The success of field fracturing construction of JH1 is a great breakthrough in deep coal seam gas fracturing technology of Jidong Oilfield, which provides reference and technical guidance for the exploration and development of similar reservoir.
4. At present, there are still some deficiencies in the understanding of deep coal seam fracturing technology, such as the research on the influencing factors and technical countermeasures of different coal structure fracture propagation forms. The exploration of large-scale, high-intensity and low-cost fracturing technology will be the direction of further optimization research.

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