A Feasibility Study of Network Hydraulic Fracture Applied to the Fissured Competent Sand Oil Reservoir

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ABSTRACT

Chang 8 oil deposit, developed in Hohe and Jihe oil fields at the southern Yi-Shan Slop of Ordos Basin, is regarded as a kind of typical sand reservoir formation with super-low porosity, poor permeability, strong anisotropy as well as locally natural faults and fractures. The previous studies believed that matrix reservoir has a good permeability, whereas fracture reservoir has a reverse manner. In the past years, there have been fewer researches on studying matrix-fracture type oil reservoir; therefore, up to now, it has been still difficult to identify whether network hydraulic fracturing can be effectively exploited in low permeable matrix-fracture type reservoir. In this paper, the author tries to analyze the feasibility of network hydraulic fracturing application in Chang 8 oil deposit from aspects such as mineral component, rock brittleness index, and development status of natural fractures, ground stress, and net press during hydraulic fracturing. The statistical results indicate that the geological condition of the research object is confirmed to meet the standard of hydraulic fracturing with a quartz content of about 40.0% to 41.6%, a brittleness index of 42.6% to 54.6%, a high angle or bevel fracture with a fracture density of 0.03 to 2.6 crack per meter, a mean of 0.38 crack per meter of developed natural fracture and horizontal layers, and the difference of two principal horizontal stresses of 2.8 to 5.5 MPa. Therefore, a certain degree of complex fractures can be built by the methods of segmental perforation, interference between multiple clusters, and the increased net pressure. Finally, we concluded that it is an important treatment to effectively develop this type of oil reservoirs by network hydraulic fracture technology in horizontal wells.

Keywords: Super Low Porosity and Permeability, Network Hydraulic Fracture, Brittleness Index, Ordos Basin

INTRODUCTION

Hohe and Jihe oil fields are both located at the southern Yi-Shan Slop of Ordos Basin in the northwest China, the production layers of which are mainly distributed in the Chang 8 Oil Deposit of YC formation with developed natural fractures and strong anisotropy [1-2]. The average effective porosity and mean permeability of Hohe oil field are 9.6% and 0.41×10^{-3} μm^2 respectively, and those of Jihe oil field are 7.5% and 0.34 mD respectively. These data corroborate that the Chang 8 oil deposit of YC formation is a typical competent sand reservoir with super-low porosity and permeability.

Chang 8 deposit currently has two types of reservoirs: matrix type and fracture type [2]. In the earlier stage, according to the concept "making a long fracture,"

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the prevalent and common treatment was to build a single fracture. But there also existed some problems: the oil leak off area was limited, the production of the single well rapidly reduced, and so on. Due to these disadvantages, the new concept "network hydraulic fracture" [3] will be introduced in this paper. The paper attempts to prove the feasibility of the application of network fracturing technology in the Chang 8 oil deposit of the south of Ordos Basin. It also provides an important guidance in the process of understanding and exploiting this type of oil reservoirs.

Mechanism

Based on the theory of rock mechanism and fracture criterion, the difference between maximum and minimum horizontal stress plays a significant role in building multiple fractures. If the difference is large enough, a couple of conjugated fissures can be created along with the direction of maximum stress. However, if it is too small, the starting-crack direction will be mainly controlled by the natural fractures of reservoir. As a result, a complex fracture network will be built with multiple strands extending to all directions. Under hydraulic fracturing, a single or several principle fractures can generate, and the natural fractures keep propagating accompanied with shear slipping, which creates more branch fissures. These fissures and the principle fractures can form a fracture network system, which allows the reconstruction volume and using rate of oil reservoir to enhance.

Therefore, the natural fractures and adequate rock brittleness are assumed as the preconditions for building multiple fractures and breaking the reservoir. Furthermore, rock dynamics features, natural feature development situation, geostress, as well as artificial stress are all dominant factors during network hydraulic fracturing [4-5].

Feasibility Study

In the previous studies, most researchers focused on the stress difference between reservoir and interlayer, Young's modulus, Poisson's ratio, etc., when they were discussing the fracture morphology. Gradually, net pressure [6], rock dynamics features [7], and properties of fracturing fluid and proppant [8] started drawing their attentions because more evidence indicated that these new factors have bigger effects.

Brittleness Index

The previous studies [9] show that brittle minerals of reservoir such as quartz and carbonate contribute to a complex network in the progress of hydraulic fracturing. When the quartz content is above 30%, the brittleness dominates [10]. The content ratio of quartz, feldspar, and debris in Chang 8 Oil deposit is approximately 2:1:1. The average quality fraction of quartz ranges from 39.01% to 41.6%.

Brittleness index can be computed if the elastic modulus and Poisson's ratio are known by [7]:

$$YM_{BRIT} = \frac{(YMSC - 1)}{(8-1)} \times 100\% \tag{1}$$

$$PR_{BRIT} = \frac{(PRC - 0.4)}{(0.15 - 0.4)} \times 100\% \tag{2}$$

$$BI = \frac{(YM_{BRIT} + PR_{BRIT})}{2} \tag{3}$$

where YMSC is Young's modulus, and PRC is Poisson's ratio; YM_{BRIT} stands for the homogenization Young's modulus, and PR_{BRIT} is the homogenization Poisson's ratio; BI represents rock brittleness index.

The rock brittleness indices of Chang 8 reservoir in E South Blocks are shown in Table 1.

Table 1 represents that the average brittleness indexes of Hohe and Jihe oil field are respectively 54.6% and 42.6%. According to the relationship between brittleness index and fracture morphology [11], Chang 8 oil reservoir is suitable to use mixing hydraulic fluid (slick water and glue solution) to build a network.

Table 1: Rock brittleness index calculation of the Chang 8 reservoir in E South Blocks.

Oil Field	Well Number	Depth (m)	Lithology	Elastic Modulus (MPa)	Poisson's Ratio	Shear Modulus (MPa)	Brittleness Index (%)
Hohe	HH12	2093.3-2094.3	Medium Sandstone	24870	0.20	10540	50.62
	ZJ21	2144.3-2149.7	Medium - Fine Sandstone	26690	0.20	11150	51.92
	HH21	1781.4-1783.5	Medium Sandstone	35180	0.19	14710	59.99
	HH103	2036.7-2038.3	Fine Sandstone	32720	0.21	13520	54.23
	ZJ5	2142.4-2143.4	Fine Sandstone	36530	0.23	14800	52.95
	ZJ9	2167.0-2169.3	Fine Sandstone	32280	0.19	13059	57.91
	Mean		Sandstone	31430	0.20	13080	54.60
Jihe	Mean(1236m)		Sandstone	20397	0.22	-	42.60

Natural Fractures

It is believed that the more the natural fractures or beddings develop in reservoir, the easier the network can be built by hydraulic fracturing. It is helpful to create network if the angle between principle and natural fractures ranges from 0° to 60°. However, if the angle exceeds 60°, the network will be not developed [13].

The core photo (Figure 1) and imaging log interpretation chart (Figure 2) show that Chang 8 oil reservoir has developed natural fractures, whose orientation keeps a same tendency with the artificial ones with a development probability of ±60%. The liner density is 0.03-2.6 cracks per meter, with an average at 0.38 cracks per meter. These demonstrate that a reservoir with developed fractures is apt to form a network system to a certain degree (Table 2).

Figure 1: The core photo of Chang 8 oil reservoir.

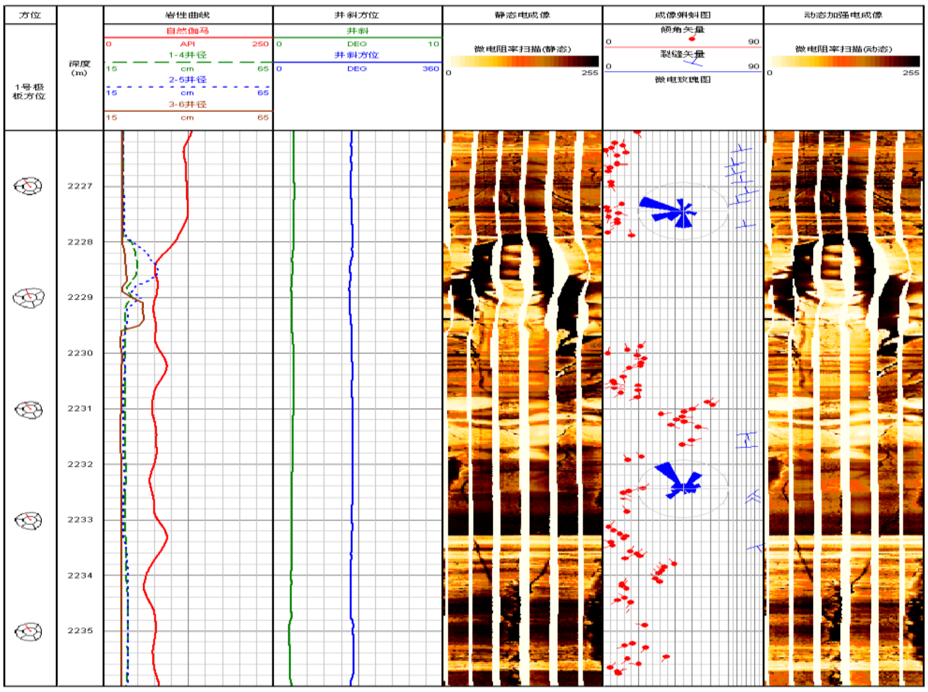

Figure 2: The imaging log interpretation chart of Chang 8 oil reservoir.

Table 2: Ability to form a complex fracture contrast table of Chang 8 reservoir indifferent blocks.

Oil Field	Fracture Intensity	Angel between Principle and Natural Fractures	Variation Coefficient of Horizontal Stress	Construction Displacement ($m^3.min^{-1}$)	Net Pressure Prediction(MPa)
Hohe	Developed	0-30°	0.152	3.0-3.5	7-9
Jihe	Developed	0-30°	0.137	2.8-4.7	6-10

Geostress

The dynamics of network fractures will be discussed on the base of natural fractures extension, which is shown in Figure 3 [12].

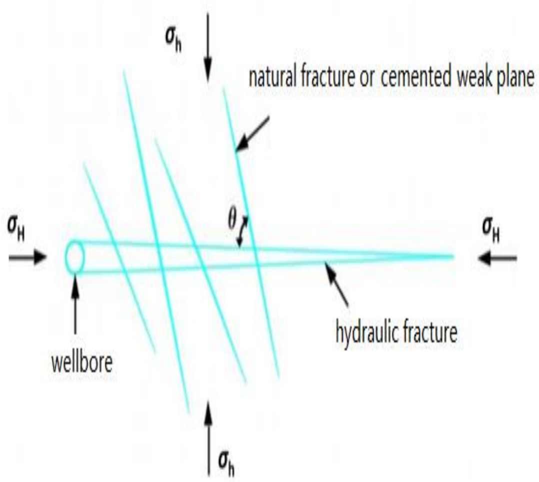

Figure 3: A schematic plot of joint network system.

Fracture morphology is influenced by the variation coefficient of horizontal stress, which is the difference between the maximum and minimum of principle stress in the horizontal well.

$$K_h = \frac{\sigma_H - \sigma_h}{\sigma_h} \tag{4}$$

where K_h is variation coefficient of horizontal stress; σ_H denotes the maximum horizontal stress, and σ_h stands for the minimum horizontal stress.

If only the variation coefficient ranges from 0 to 0.3, hydrofracture will form complex cracks with branches near the borehole, which has more small fissures extending along with the dominant direction at the same time. If the coefficient is from 0.3 to 0.5, the branches will propagate near the borehole and eventually form a network under the pressure of net stress. If the coefficient exceeds 0.5, hydrofracture will mainly build a single fracture rather than a network.

According to the above theory, the horizontal stress variation coefficients of two studied areas are 0.14 to 0.17 and 0.137, and they are able to build complex network fractures. (Table 3).

Table 3: Horizontal stress difference coefficient of Chang 8 reservoir indifferent blocks.

Well Number	Lithology	Depth (m)	Vertical Geostress (MPa)	Maximum Geostress (MPa)	Minimum Geostress (MPa)	Variation Coefficient
HH21	**Medium Sandstone**	1781.4-1783.5	42.6	35.2	29.9	0.177
ZJ9	**Fine Sandstone**	2267.0-2268.5	56.1	44.8	39.2	0.143
HH103	**Fine Sandstone**	2036.7-2037.8	49.7	40.2	34.8	0.155
HH12	**Medium Sandstone**	2093.3-2093.8	51.3	41.3	35.9	0.150
ZJ21	**Medium - Fine Sandstone**	2144.3-2147.2	52.8	42.4	36.9	0.149
ZJ5	**Fine Sandstone**	2143.4-2143.8	52.7	42.4	36.8	0.152
Hohe Mean		-	50.87	41.05	35.58	0.154
Jihe Mean		1236	28.4	23.6	20.8	0.137

Net Stress

Net stress is the differential between the pressure inside the cracks and the minimum stress of layers. It is relative to formation Young's modulus, reservoir depth, the viscosity of hydraulic fluid, construction discharge, and fracture length.

$$p_{net} \propto \frac{E}{h}\left[\mu Q^{1/2} L\right]^{1/3} \quad (5)$$

where P_{net} is net stress, and E is formation Young's modulus; h represents the reservoir depth, and μ is the viscosity of hydraulic fluid; Q stands for construction discharge, and L is fracture length.

If net pressure is equal to 80% of the difference between maximum and minimum stress, the fracture height will be out of control [14]. However, based upon the minimal energy principle, if it becomes greater than the difference, the energy will be released along with the orientation of the shortest distance, and it will change fractures direction, and finally form a network. Therefore, fracture morphology changes are accompanied with net pressure and the difference between the maximum and the minimum stress. The parameters which have a direct influence on net pressure are construction discharge and hydraulic fluid viscosity.

The data obtained from 60 vertical wells of Chang 8 oil deposit in the Hohe oil field show that there is a liner correlation between net pressure and construction discharge. The construction discharge is 1.2-2.2 m^3/min, and the net pressure is 2.0-5.0 MPa. The difference between the maximum and minimum stress is 5.4 MPa, which is greater than the net pressure (Table 4). If construction discharge exceeds 2.5 m^3/min, there are more than 70% wells, whose net pressure is above 6 MPa. In those horizontal wells, the construction discharge is mainly from 3.0 to 3.5 m^3/min. The net pressure is above 7 MPa, exceeding the difference between the maximum and minimum stress, and creating a relatively complex network.

The data collected from the staged fracturing of well HH12P142 in the Hohe oil field is analyzed by the method of net pressure matching in order to confirm the effects of net pressure on fracture morphology.

Table 4: Net pressure fitting data tables of well HH12P142.

No.	Construction Discharge $m^3.min^{-1}$	Injection volume (m^3)	Fitted net pressure (MPa)	Fitted Fracture Length (m)	Fitted Fracture Height (m)	Difference between Maximum & Minimum Stress (MPa)	Morphology of Net Pressure Curve	Transmit the Natural Fractures
1	4.0	221	9.6	94	45	5.6	falling	Yes
2	4.0	262	9.3	96	47		falling	Yes
3	4.0	262	8.8	95	46		falling	Yes
4	3.4	225	11.7	85	37		flat	No
5	3.6	187	6.5	108.2	32.1		flat	No

The results show that under the cementing condition, the fitted net pressure is generally greater than the difference between the maximum and minimum stress. It implies that the fractures tend to be complex. *G* function analysis also proves that there is an obvious transmission between the natural fractures, and it has an apparent trend to grow multiple fissures. From above discussions, we can predict the regular tendency of net pressure in the course of hydraulic fracture transformation as follows:

- If the reservoir varies in depth, and the construction discharge is about 2.0 m^3/min, the net pressure can be generally controlled around 5.4 MPa, which is the planar principle stress difference between the maximum and minimum.
- If the reservoir depth increases, net pressure is governed by construction discharge, which is more than 2.5 m^3/min.
- If construction discharge exceeds 3.0 m^3/min, net pressure will surpass the stress difference, and the fractures tend to be complicated.

Based on the above analysis, it can be deduced that net pressure in the hydraulic fracture of Chang 8 oil reservoir is greater than the planar difference of the maximum and minimum stress, and the stress deviations between reservoir and interlayer should be influenced by their behaviors. If the condition is allowed, the fracture height is limited, and it tends to grow into network fractures. However, if the deviation is too small, the fractures prefer to expand in a vertical direction, that is: (1) net pressure > planar difference > deviation between the reservoir and interlayer, and the network fractures prevail; (2) net pressure > deviation between reservoir and interlayer > planar difference, and the fracture height would lose control.

It is concluded that different construction parameters and network hydraulic fracturing techniques should be applied to Chang 8 oil reservoirs with various features in the south of Ordos Basin. A certain degree of complex fractures can be formed by increasing the net pressure through large displacement construction, changing the fracturing fluid performance, or adding temporary plugging agent. When the horizontal stress difference is less than 6 MPa, net pressure can be increased by large displacement construction until it exceeds the difference between two minimum planar stresses. If the propagation of principle fracture is arrested, the net pressure will start to increase. Until the pressure is large enough, the fracture changes its propagation direction and produces shear fraction in order to link the distal end of natural fracture and eventually build a fracture network.

RESULTS AND DISCUSSION

Field Test

Multi-section hydraulic fracturing with drillable bridge plug was employed to test the reservoir of JH69P25 well (brittleness index=45.7%, variation coefficient between the maximum and minimum stress=0.139) in Jihe oil field. There were 12 sections with 23 clusters in a horizontal segment, where mixing hydraulic fracturing fluid systems (a:0.15%HPG+1%BRD-S10 anti-water blocking agent+1.0%KCL+0.08% bactericide; b: 0.35%HPG+0.5%BRD-S10 anti-water blocking agent +0.3%CX-307 cleanup additive +1.0%KCL+ 0.15% bactericide +0.3% low-temperature activator) and multiple-group proppant system (40/70 mesh silt was used to support micro-fracture in the early stage, and the bending friction was decreased through the abrasion of crack surface with 20/40 mesh silica sand during the middle stage in order to reduce the risk of construction; 20/40 mesh silica sand was employed to improve the flow conductivity of the propped fractures in the late stage) are used. Sections 2-12 adopted a two-cluster perforation method, and the perforation level of horizontal section was enhanced through the optimization of perforation parameters and length by a limited entry fracturing principle. We performed various density patterns perforation to balance the stress difference between the sections and achieve an equilibrium assignment. The horizontal geostress is calculated by its analysis software (e.g. sections 8 and 9), and then the other data of geostress profile are acquired (Table 5). Combined with the analysis of geology and logging materials, it is believed that sections 8-9 are able to perform cluster perforation. Segment 1817-1819 m, 1837-1839 m, 1874-1876 m and 1894-1896 m are selected to be the perforated intervals, which have similar two-cluster properties, and the difference between the maximum and minimum in situ stress is less than 1 MPa. There are 12 hydraulic fracturing segments used with drillable bridge plug (section 2-12 used with multi-cluster perforation), and the total liquid amount is 5441.8 m^3, adding 497.2 m^3 sand (Table 6).

Table 5: Cluster type perforation condition analysis of the data of sections 8 and 9 in HH12P142 well.

Fracturing Section	Perforation Section (m)	Natural Gama (API)	Interval Transit Time ($\mu s.m^{-1}$)	Porosity (%)	Permeability (mD)	Minimum Geostress (MPa)
No. 9	1837-1839	80.2	230.5	10.3	0.69	26.0-26.4
	1817-1819	84.0	233.8	10.8	0.75	26.3-26.7
No. 8	1894-1896	76.5	228.1	9.7	0.63	26.8-27.2
	1874-1876					27.0-27.8

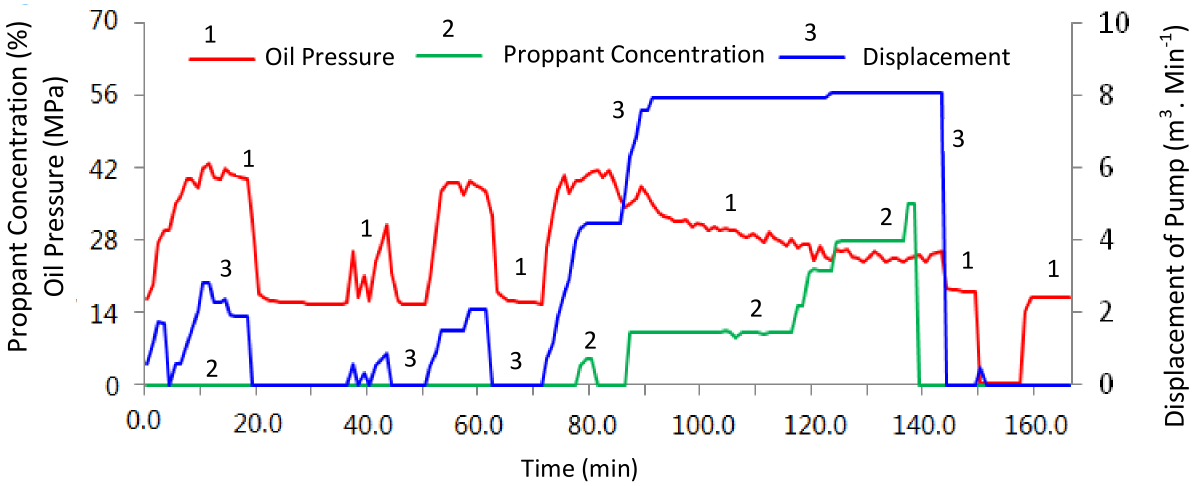

Figure 4: Segmented clusters fracturing construction graph of 8 sections.

Table 6: Different fracturing construction pressure change of well JH69P25

Fracturing Section	Perforation Depth (m)	Hole density (m)	Perforation Number (hole)	Construction Displacement ($m^3.min^{-1}$)	Initial Construction Pressure (MPa)	Construction Pressure Prior to Pump off (MPa)	Change Value of Construction Pressure (MPa)	Pump off Pressure (MPa)	Total Friction (MPa)	Types of Pressure Variation
1	4	20	80	7	38.9	38.3	0.6	26.7	11.6	I
2	2	20	40	7	39.2	36.9	2.3	25	11.9	I
3	2	16	32	8	38.6	38.4	0.2	26.5	11.9	I
4	2	16	32	4.0-7.0	40.8	40.2	0.6	31	9.2	-
5	2	20	40	8	36.1	27.1	9	20.5	6.6	II
6	2	20	40	8	36.3	28.2	8.1	20.6	7.6	II
7	2	16	32	8	36	24.8	11.2	19.6	5.2	II
8	2	20	40	8	39.1	26.5	12.6	18.5	8	II
9	2	16	32	8	35.3	26.8	8.4	19.3	7.1	II
10	2	20	40	8	27.4	26.2	1.2	19	7.2	I
11	2	16	32	8	41.5	27.4	14.1	18.5	8.9	II
12	2	20	40	8	41.7	28	14.7	17	11	II

The results can be obtained by analyzing the hydraulic construction pressure, pump off pressure as well as the perforation friction of section 12 of JH69P25 well; under the similar stratum conditions, if the minimum differential stress is small (within 1 MPa), the pump off pressure can reflect net pressure, and the high displacement will lead to low net pressure (Figure 4). From section 1 to 12, the pump off pressure of section 12 is the lowest, and its difference is 1.4-9.7 MPa. The net pressure of section 12 approximately reaches 8.6 MPa (construction displacement 8.0 m^3/min); in Figure 5 the minimum differential stress is less than 1 MPa, and the coefficient of flow distribution is about 4.8. The casing performance requires a large displacement and a balanced flow distribution. The lower the differential stress of two break-off points is, the more balanced the flow distribution become, and then the subsection multiple clusters are more likely to grow into the multiple fractures. From what discussed above, it can be deduced that sections 8 and 9 propagate two fractures (or complex fractures), which causes the flow distribution to change and decreases the single fracture flow and net pressure.

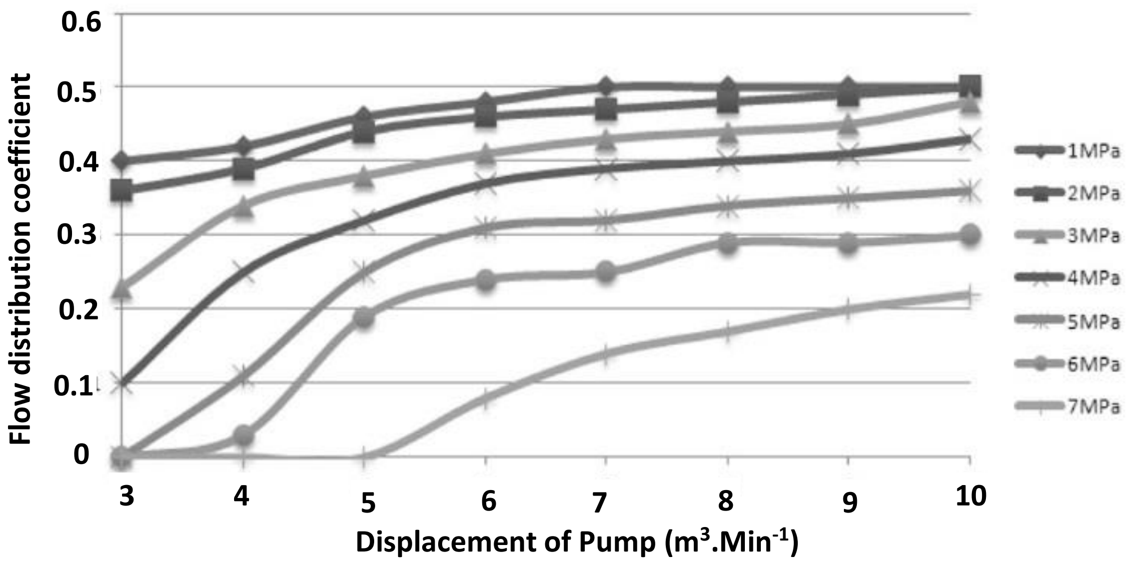

Figure 5: Relationship between different reservoir stresses and the influence of the flow within the cluster of the Chang 8 reservoir in Jihe oil field.

It takes 4 days to discharge fluid after hydraulic fracturing of JH69P25, and then the oil flows back at a rate of 26.2%. The initial peak of oil production reaches 2.93 t, while the current daily production is 2.55 t (daily fluid output 14.99 m^3), and the water content is 82.0% (working fluid level 750 m, chlorate 18909 mg/lit, flow back rate 46.9%) the cumulative production has been up to 288.1 t.

CONCLUSIONS

According to the results, the following conclusions can be drawn:

The brittleness index of Chang 8 reservoir in the south of Ordos Basin is 42.6-54.6%, ranging within a middle-high scale. The development probability of natural fractures is ±60% with a crack density of 0.38 lit/m, and the difference of the two horizontal principal stresses ranges from 2.8 to 5.5 MPa. The natural fractures and horizontal beddings are commonly developed, so its geology and stress conditions are suitable for network hydraulic fracturing to enhance the oil production.

Chang 8 oil reservoir of JH69P25 well has built complex fractures by means of subsection multiple clusters technique. Its sound effect proves that network hydraulic fracturing is feasible to be performed in this kind of reservoirs.

As suggested, it is necessary to perform the staged multi-cluster fracturing of horizontal wells in a fracture type of Chang 8 reservoir in the south of Ordos Basin. Various density alterations should be applied to field test by mixing a hydraulic fluid system (slick water + base fluid + crosslinker gel) and multi-sized proppant model to carry out the network fracturing test. At the same time, we should strengthen the underground seismic monitoring; do more analysis about the fracture extension morphology; determine a definite relation - ship between design parameters, reconstruction volume and the single well effect; and evaluate the complexity of fracturing network as well as the reconstruction volume.

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