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Yuan Yao

China University of Petroleum, Beijing

Yinghao Shen

shenyinghao@cup.edu.cn

China University of Petroleum, Beijing

Hao Lu

China University of Petroleum, Beijing

Menglin Zhang

China National Petroleum Corporation (China)

Na Zhang

China National Petroleum Corporation (China)

Kunyu Wu

China National Petroleum Corporation (China)

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Evaluation of Post-fracturing Fractures and Production Analysis in Yingxiongling Shale Oil

Yuan Yao ¹, Yinghao Shen^{1,*}, Hao Lu¹, Menglin Zhang ², Na Zhang² and Kunyu Wu ²

AFFILIATIONS

1.State Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum (Beijing), China.

2.Research Institute of Petroleum Exploration and Development, CNPC Qinghai Oilfield, China.

Correspondence: State Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum (Beijing); shenyinghao@cup.edu.cn;

Abstract: Due to the pronounced lithological heterogeneity inherent in mixed sedimentary shale oil reservoirs, the dynamic behavior and efficiency of fractures during the post-fracturing well killing and flowback processes are critical factors constraining long-term productivity. To elucidate the evolution of fracture characteristics and quantify the impairment of the fracture system during these processes, this paper proposes a comprehensive analytical approach integrating short-term pressure transient diagnosis with early production analysis. Initially, based on the pressure decline curve during the well-killing period and the analysis of pump shut-down pressure, the near-wellbore fracture closure behavior and fracturing fluid leak-off characteristics are diagnosed to assess the initial efficiency of the fracture network. Then, flow regime analysis during the early flowback stage is employed to explain the transition characteristics from linear flow to formation radial flow. Furthermore, a model for calculating the loss rate of the fracture system is established using the material balance principle, quantifying the reduction in fracture conductivity and geometric dimensions resulting from inadequate proppant support. Subsequently, production decline analysis is conducted. Field application demonstrates that this method can effectively reveal the complex post-fracturing dynamics of the fracture network in mixed sedimentary reservoirs. This provides a theoretical foundation for optimizing post-fracturing management strategies and enhancing individual well productivity.

Keywords : Mixed shale oil; Well killing; Pressure decline analysis; Fracture loss ratio; Assessment of post-fracturing

1.Introduction

China is endowed with abundant terrestrial shale oil resources, with geological resources estimated at up to 283×10^8 t^[1], indicating promising exploration potential. Based on the lithological characteristics of shale oil sweet spots and the source-reservoir relationship, these resources can be categorized into three types: interbedded, mixed, and shale types^[2]. The Lower Ganchaigou Formation in the Yingxiongling of the Qaidam Basin represents a mixed sedimentary shale oil reservoir, predominantly composed of dolomitic calcareous shale and calcareous dolomitic shale, with a stratigraphic thickness of 1000-1200 m^[3]. This area exhibits substantial resource potential, among which Well CP1 has achieved the most favorable development performance, with a maximum daily oil and gas production of 132 t, cumulative oil production of 1.5×10^4 m³, and cumulative gas production of 194.6×10^4 m³ ^[4].

Lithology in mixed sedimentary shale oil reservoirs varies frequently, with the thickness of individual lithological layers generally being less than 1 m. Vertically, these formations exhibit source-reservoir lithological assemblages that are capable of both hydrocarbon generation and storage, all such assemblages are potentially productive, and strong overall reservoir heterogeneity. Specifically for the Yingxiongling shale oil, the reservoir lithofacies are mutually superimposed, with the optimal source-reservoir combination being layered calcareous dolomite interbedded with laminated dolomitic limestone, which is characterized by high movable hydrocarbon content^[2,3]. Currently, the development of shale oil in this area predominantly employs volumetric fracturing techniques^[5]. However, the high-frequency variation in lithofacies, coupled with high horizontal differential stress, pose significant challenges to hydraulic fracturing stimulation, and the propagation of artificial fracture is complexity. After volume fracturing, during the well-killing stage, the fracturing fluid imbibes into the matrix pores under capillary force, achieving oil recovery through oil-water displacement. Studies have shown that implementing well-killing after fracturing facilitates fluid imbibition displacement and energy storage, and the effective utilization of backflow fluid for entrainment and displacement is central to enhancing oil recovery^[6,7]. All these make the evaluation of the post-fracturing fracture network and its connectivity effectiveness a critical factor for subsequent productivity enhancement.

Currently, most post-fracturing analysis methods are developed based on iterative approaches derived from Nolte's G-function derivative analysis^[8]. The core of these methods involves describing and analyzing post-fracturing reservoir parameters and

fracture characteristics using pressure data, flowback data, and tracer diagnostics, among other detection techniques^[9-15]. With the large-scale development of unconventional shale reservoirs, reservoir heterogeneity has led to significant vertical and horizontal variations in mechanical properties, resulting in increasingly complex fracture propagation and diverse pressure decline curve responses, which contributed to model non-uniqueness^[16]. For flowback analysis, Clarkson proposed the rate transient analysis method, which applies the superposition principle to conduct long-term production analysis of unconventional reservoirs to obtain reservoir and fracture parameters^[17]. Additionally, complementary diagnostic data such as tracer analysis and distributed fiber optic sensing are typically integrated with pressure transient and production data for comprehensive analysis^[18,19].

However, post-fracturing analysis methods are limited for mixed sedimentary shale oil. Traditional well logging and well testing evaluation techniques generally assume homogeneous reservoirs, rendering them poorly applicable to heterogeneous reservoirs characterized by complex superimposed lithofacies. Taking a certain development platform of Yingxiongling shale oil as an example, fracture characteristics are characterized through pressure variations during the fracturing and soaking period, fracture network efficiency is analyzed using early production performance during the initial flowback stage, and production decline analysis is conducted to reveal the significance of the effective fracture network and propose corresponding operational strategy adjustments.

2. Background of research region

2.1 Geological features

The Qaidam Basin, located in the northern part of the Qinghai-Tibet Plateau, is surrounded by mountains and exhibits an elevation range of 2800-3600 m, with an average altitude of 2950 m. It is one of the seven major onshore petroliferous basins in China. Influenced by the Cenozoic uplift of the Qinghai-Tibet Plateau, it has evolved into a tectonically complex, superimposed, and reorganized intermountain basin^[20,21]. The Yingxiongling structure hosts the highest quality Paleogene source rock system in the Qaidam Basin, with sedimentary environments characterized by semi-deep to deep lacustrine subfacies, representing a saline lacustrine basin with substantial sedimentary thickness. Platform C is located within the 14th-15th zone of the E₃² interval of the Lower Ganchaigou Formation in the Yingxiongling reservoir. The formation exhibits

complex mineral compositions, including clay, quartz, feldspar, calcite, and dolomite (Figure 1). The target interval primarily comprises laminated calcareous dolomite and layered calcareous dolomite; however, these two lithofacies exhibit high-frequency interbedding, resulting in rapid variations in physical properties^[3].

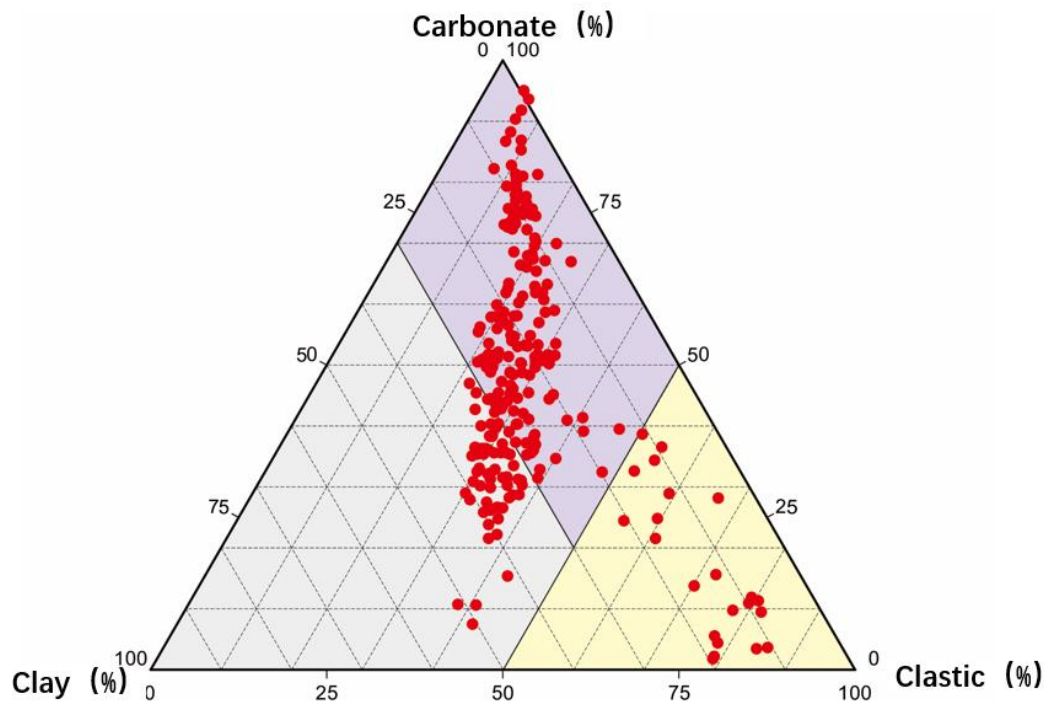


Figure 1 Diagram of Lithology Ternary Classification

2.2 Introduction of development and fracturing

At Platform C, two wells have been deployed in the zone14, with target interval thickness ranging from 3.8 m to 4.1 m, porosity of 5%-7%, and average oil saturation of 60%. In the zone 15, two wells have been deployed, with target interval thickness ranging from 2.9 m to 3.3 m, porosity of 7%-10%, and average oil saturation of 55%. The horizontal well spacing is 600 m, with a vertical distance of 63 m between the two intervals. The specific well layout is illustrated in Figure 2.

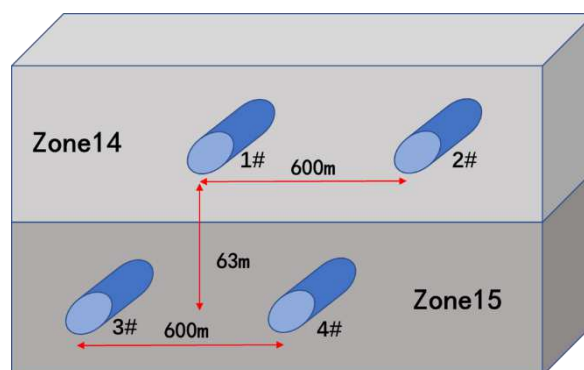


Figure 2 Diagram of platform C

Zone 14 generally exhibits relatively developed laminations, while the zone 15 interval is characterized by relatively developed layered structures. Compared to layered calcareous dolomite, laminated calcareous dolomite displays higher total organic carbon (TOC) content but poorer brittleness^[22]. Detailed reservoir parameter characteristics for the two intervals are presented in Table 1.

Table1 Comparison of reservoir characteristics in platform C

Well Name	TOC	GR /gAPI	AC / μ m/s	Porosity /%	Oil Saturation /%	Compressible index	Minimum horizontal stress/MPa	Poisson ratio	Yang's modulus	Matrix brittleness
1	5.78	89.13	179.19	5.35	48.70	0.50	78.66	0.30	39.90	64.66
2	7.95	68.80	180.60	5.12	46.79	0.51	75.76	0.27	41.22	66.32
3	12.16	65.09	181.66	5.92	50.03	0.51	79.30	0.30	40.86	66.74
4	3.63	64.77	176.14	5.82	46.07	0.53	78.35	0.29	39.86	57.35

This platform was transformed by “closed space+ simultaneous fracturing”, the average stages per well are 27, with the pump rate of 15.7m³/min, The average fluid volume per stage is approximately 1500 m³, and the proppant volume per stage is about 150 m³. Specific treatment parameters are detailed in Table 2.

Table 2 parameters of fracturing in platform C

Well Name	Stage	Pump rate (m ³ /min)	Liquid volume (m ³)	Sand volume (m ³)	Liquid intensity (m ³ /m)	Sand intensity (m ³ /m)
1#	24	15.6	37608.3	3994	26.8	2.7

2#	19	15.6	34620.5	3641	29.0	3.1
3#	27	16.0	41661.5	3960	28.4	2.7
4#	27	15.5	47068.9	4327	31.7	2.9
Average		15.7	40240	3981	29.0	2.9

3 Methods

3.1 Analysis of pressure decline curves and diagnosis of fracture characteristics during the well killing

Between the completion of horizontal well fracturing and production, a short-term shut-in operation is typically conducted to allow bottom-hole pressure dissipation, thereby enhancing formation energy while accelerating artificial fracture closure to prevent proppant flowback upon well opening^[23]. The wellhead pressure during the well killing period can characterize the fracture network formed by fracturing^[24,25]. This study employs the pressure fall-off curve diagnostic method proposed by Wang Fei^[26], by plotting the pressure drop and its derivative as a function of time on a log-log scale. The curve is divided into five characteristic stages, establishing the corresponding relationship between fracture parameters and curve morphology (Figure 3).

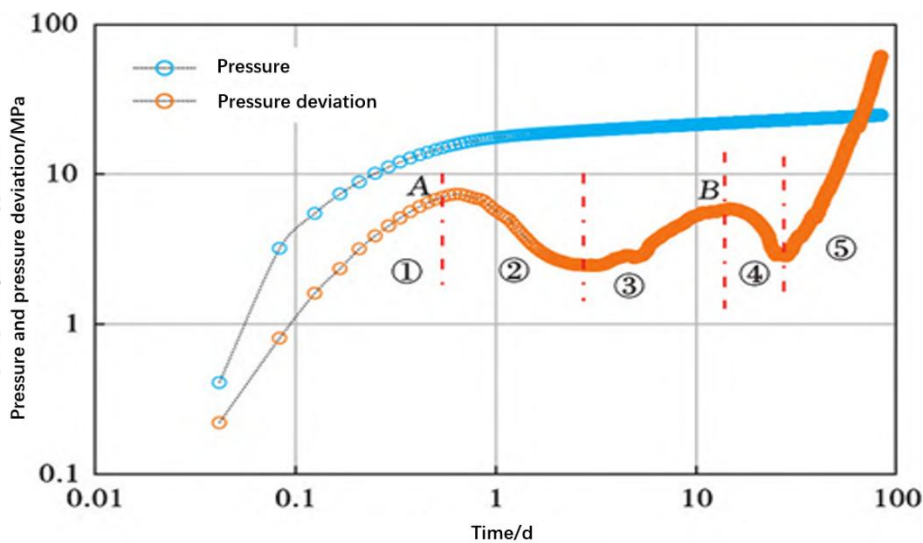


Figure 3 Bottom-hole pressure drop and derivative double-logarithmic curve during the well killing period^[26]

Table 3 Characteristic trends and corresponding parameter explanations

parameter	Features in the figure	explanation
Half-length of the main fracture	Duration of stage ① and the rate of pressure drop at point A at the end	The longer the main crack, the greater the ending time, and the larger the derivative value at point A.
Density of the secondary fractures	The depth of 'V' in stages ② ③	The greater the density, the deeper the 'V' shape.
Permeability of secondary fractures	The derivative value of the 'V' drop at beginning, and the B value in the end time of the first 'V' shape	The greater the permeability of the secondary fracture, the earlier the start and end times of the first 'V' shape, and the smaller the derivative value corresponding to point B.
Width of the secondary fractures	The depth and duration of the two 'V' shapes	The narrower the secondary fracture width, the deeper the two 'V-shapes' and the shorter the duration.
Oil content in the matrix	Characteristic curve shapes other than those controlled by the main fracture in stage ①	When the oil content is relatively low, the derivative curve of the well shut-in pressure drop slopes upward overall, showing a slanted 'Z' shape.

3.2 Identify the flow regime during the flowback

For unconventional shale oil reservoirs, conventional reservoir engineering operations such as constant rate or constant pressure production are often impractical during the production process. Therefore, according the methods suggested by Clackson^[27], using rate-normalized pressure (RNP) and material balance time (MBT) as coordinates for production analysis, which facilitates more effective identification of flow regimes, as well as determination of fracture parameters and reservoir characteristics.

Define the $\frac{p_{fi}-p_{wf}}{q_w}$ as the RNP (Rate normalized pressure), indicated the ratio of pressure difference of initial well bottom pressure and present pressure and liquid rate, it can be shown the pressure drop under different production and pressure. The p_{fi} means the initial pressure in the fracture; p_{wf} represent the well bottom pressure; q_w represent the water production. Material balance time (MBT) is defined as the ratio of cumulative fluid production to the daily production rate, representing the equivalent

time required to produce the same cumulative fluid volume at a constant production rate.

In contrast to conventional flow regime analysis, the linear flow regime in unconventional reservoirs generally does not exhibit the characteristic half-slope behavior on a log-log plot. This deviation arises from anomalous diffusion caused by strong reservoir heterogeneity and stress sensitivity. Through derivation, it is established that the characteristic slope for identifying flow regimes in unconventional reservoirs satisfies the following relationship, the detailed derivation process is in Appendix A.

$$m = \frac{d\ln(RNP)}{d\ln(MBT)} \propto \frac{1 - \beta}{2} \quad (1)$$

When $\beta = 0$, corresponding to conventional diffusion, the slope equals 0.5. When $\beta < 0$, the slope exceeds 0.5, indicating a decrease in permeability or an increase in fluid viscosity. When $\beta > 0$, the slope is less than 0.5, suggesting an increase in permeability and improved fluid mobility. Therefore, analysis of the slope during the early linear flow stage enables a preliminary assessment of fluid flow behavior within the reservoir.

3.2 Calculation of fracture volume loss

Abbasi proposed a material balance model for estimating fracture volume using early single-phase flowback data; however, it should be noted that this model is not applicable to unconventional shale oil and gas reservoirs exhibiting early multiphase flow. This material balance model primarily describes a linear relationship between rate-normalized pressure and material balance time^[28]. D.O.Ezulike, employing an oil tank model to simulate fracture flowback, indicated that fracture closure serves as the dominant drive mechanism during the flowback period. He categorized the flow regimes during early flowback into three stages: early transient flow, pseudo-steady state flow, and late transient flow. Due to the pressure buildup effect, water is initially produced from the fractures; only after depletion within the fractures does matrix-to-fracture seepage occur. Consequently, during the early flowback stage, it can be assumed that all water originates from the fracture volume, with the flow regime exhibiting pseudo-steady state characteristics^[29]. Fu proposed that the early flowback flow regimes can be classified into transient linear flow within fractures, fracture closure displacement, transient fracture displacement, and transient linear flow within the matrix. Transient linear flow can be identified by a half-slope on the log-log plot of

RNP versus MBT; however, its rapid occurrence, often masked by wellbore storage effects, poses challenges for identification. The fracture displacement process can be identified by a unit slope on the log-log plot of RNP versus MBT, characterizing the expulsion of water from fractures when the pressure disturbance reaches the fracture boundaries in a closed system. The transition from fracture displacement to transient linear flow within the matrix can be identified by a deviation from the unit slope on the log-log plot of RNP versus MBT, typically occurring during hydrocarbon influx from the matrix into the fractures^[30]. Therefore, the loss of fracture volume predominantly occurs during the early flowback stage and becomes minimal during the later flowback stage.

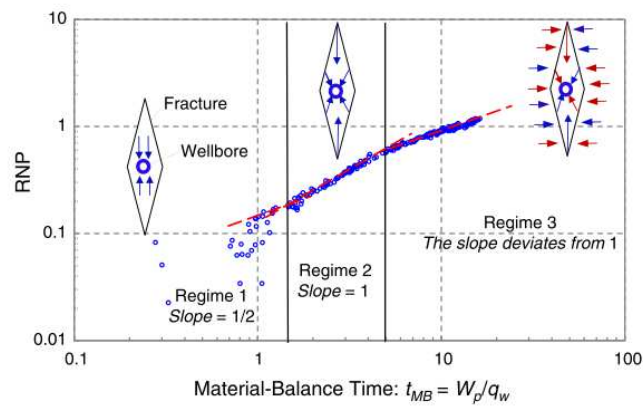


Figure 4 Diagram of flow regime and fracture closure stage in flowback period^[29]

1. Calculation of initial fracture volume

Using decline curve to get the initial fracture volume, according to the Arps's model:

$$\frac{1}{q_w} \frac{dq_w}{dt} = -D_i q_w^b \quad (2)$$

Where, D_i and b are decline constant, When the decline follows exponential decline, $b=0$; for hyperbolic decline, $0 < b < 1$; and for harmonic decline, $b = 1$.

It is generally accepted that the decline curve of low-permeability oil and gas reservoirs conforms to the pattern of harmonic decline. Therefore, under harmonic decline, there exists a linear relationship between cumulative water production and daily water production, as shown in the following equation:

$$W_p = -\frac{q_{wi}}{D_i} \ln\left(\frac{q_w}{q_{wi}}\right) \quad (3)$$

Where, q_{wi} is the initial water rate during the flowback period

Transform the formula (6):

$$W_p = -\frac{q_{wi}}{D_i} \ln(q_w) + \frac{q_{wi}}{D_i} \ln(q_{wi}) \quad (4)$$

Based on the above equation, a semi-log plot of cumulative water production versus daily water production is constructed, yielding a linear relationship. Extrapolating this linear trend to the point where daily water production reaches zero gives the corresponding cumulative water production, which represents the estimated ultimate water recovery (W_{ulti}). Furthermore, since the initial fracture volume can be approximately regarded as the ratio of the ultimate water recovery to the initial water formation volume factor (B_w), as expressed in Equation (5), the initial fracture volume is obtained. Under general conditions, the water formation volume factor can be considered as unity.

$$V_{fi} = \frac{W_{ulti}}{B_w} \quad (5)$$

Through above process, the initial fracture volume can be obtained.

2. Calculation of the effective fracture volume

When the flow get into the psedo-stable stage, the material balaenced formula can be shown as:

$$\frac{p_{fi} - p_{wf}}{q_w} = \frac{1}{V_f C_t} \times t \quad (6)$$

Where, p_{wf} is the well bottom pressure, q_w is the water rate.

Considering variations in production rates, subsequent studies have frequently employed material balance time (MBT) to represent the equivalent time required for a well to produce an equivalent volume of fluid at a constant production rate. It should be noted that the MBT referred to here differs from that used in flow regime analysis and is defined as the ratio of cumulative water production to daily water production.

$$MBT = \frac{W_p}{q_w} \quad (7)$$

Where, W_p is cumulative water rate.

Therefore, formula(6) can be shown as:

$$RNP = \frac{1}{V_f C_t} MBT = \frac{1}{V_f (C_f + S_w C_w + S_o C_o)} \quad (8)$$

It can be observed from Equation (6) that when RNP is plotted against production time in a Cartesian coordinate system, its slope can be expressed as the product of fracture volume and total compressibility. Therefore, the unknown parameters include fracture volume (V_f), fracture compressibility (C_f), and water compressibility (C_w). Given that water compressibility is typically several orders of magnitude smaller than

other compressibilities, its role in the flowback process can be considered negligible. Meanwhile, parameters such as gas compressibility (C_g), gas saturation (S_g), and water saturation (S_w) can be substituted using laboratory experimental data.

$$S_g = 1 - S_w \quad (9)$$

$$S_w = S_{wi} - \frac{W_p}{V_{ef}} \quad (10)$$

For early single-phase flowback, the initial water saturation (S_{wi}) within the fractures can be considered as unity. W_p denotes the cumulative water production.

Due to the strong sensitivity of fracture volume to fracture compressibility, determining the range of C_f cannot be reliably achieved through simple laboratory experiments. Instead, following the approach proposed by Williams-Kovacs and Clarkson, the proppant within the fractures can be assumed to be analogous to the mineral phase in the Aguilera chart model. Accordingly, based on Peters cube packing model, the range of proppant concentration is determined to be between 47.5% and 100% [31,32].

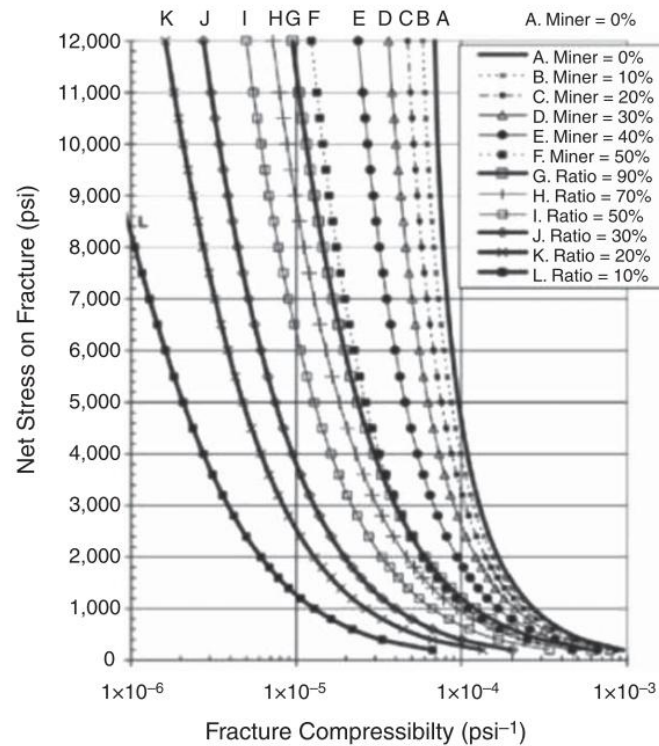


Figure 5 Diagram of the relationship between fracture compression coefficient and net stress^[31]

The above figure can be described by the following equation:

$$C_f = a(p_n)^{-b} \quad (11)$$

Through regression analysis, the values of the two constants, a and b , can be determined.

3. Calculation of fracture volume loss ratio

The fracture loss ratio (R_f) is defined as the ratio of the difference between the effective fracture volume and the initial fracture volume to the initial fracture volume.

$$R_f = \frac{V_{fi} - V_{ef}}{V_{fi}} \quad (12)$$

Based on the parameters obtained through the above steps, the fracture loss ratio can be calculated.

4. Field application

4.1 Features of fracture from pressure decline analysis

Based on high-frequency pressure data from four wells at Platform C during the well killing period, pressure drop and derivative log-log curves were plotted (Figure 6). By integrating the "V"-shaped feature with parameter interpretation criteria, a comparative analysis of fracture characteristics was conducted.

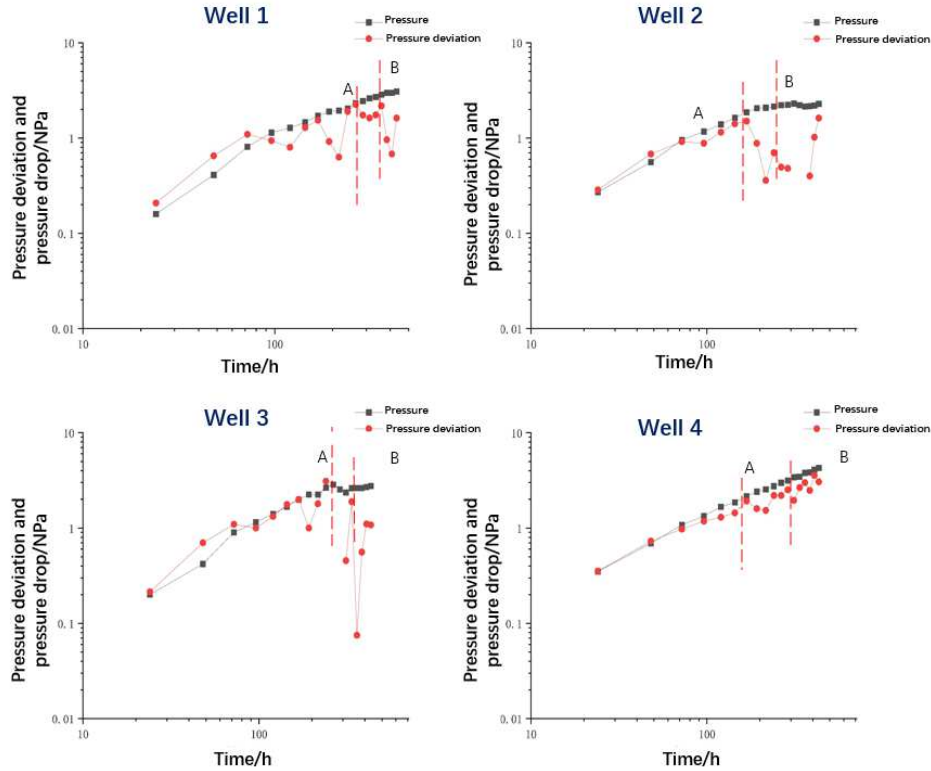


Figure 6 Log-log curve of wellbore pressure decline and pressure decline derivative versus time for Platform C

1.Regarding primary fracture half-length, Wells 1 and 4 exhibit the most favorable performance. This difference may be attributed to the larger fracturing scale during stimulation in these wells, which resulted in a higher concentration of fracture-initiation energy and provided advantageous conditions for fracture propagation.

2.In terms of secondary fracture development characteristics, the density and width of secondary fractures in Wells 1 and 2 surpass those in Wells 3 and 4. This is speculated to be associated with the higher brittleness index of the reservoirs in the former two wells. Facilitated by high brittleness, secondary fractures are more readily generated during fracturing, and the fracture wall support is enhanced, thereby improving the scale of secondary fracture development.

3.The permeability of secondary fractures remains generally consistent across all four wells. This common characteristic is governed by the inherent physical properties of the reservoir, indicating that fundamental attributes such as mineral composition, pore structure, and connectivity play a dominant role in determining secondary fracture permeability, which is not significantly affected by variations in inter-well stimulation parameters.

4.Regarding oil-bearing characteristics, the oil content in Well 4 is significantly lower than in the other three wells. Based on an integrated analysis of its fracture development characteristics, the primary reason is inferred to be the lower fracture complexity during the fracturing of Well 4, which led to inefficient fracturing fluid displacement.

In summary, based on the effectiveness of fracturing stimulation, the wells are ranked as follows: Well 1 > Well 2 > Well 3 > Well 4. This ranking exhibits a certain correlation with the scale of the fracturing operations.

4.2 Analysis of flow regime

Flow regimes were identified using the RNP versus MBT curve, and data corresponding to the pseudo-steady state flow (characterized by a unit slope) were selected for fitting the slope m .

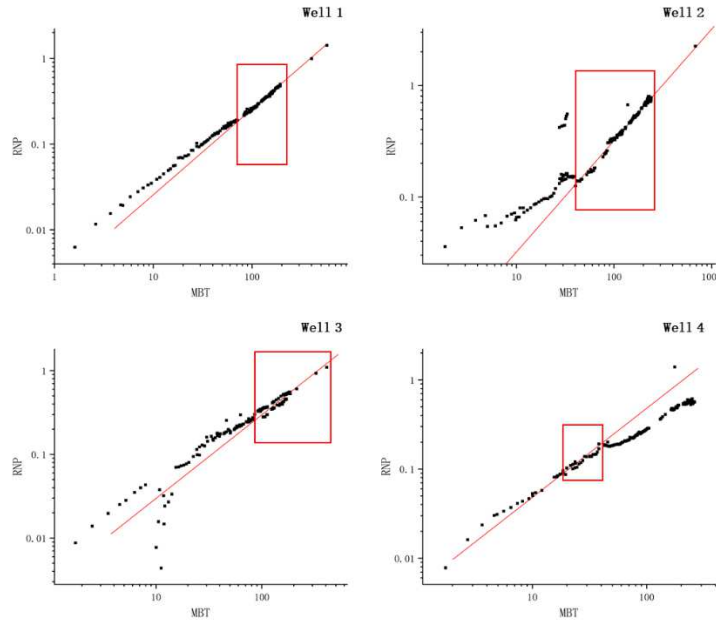


Figure 7 Platform C Flow Regime and Slope Fitting Range

It was also observed that prior to reaching pseudo-steady flow, the linear flow slopes for Wells 1, 2, 3, and 4 were 0.75, 0.47, 0.71, and 0.65, respectively. This indicates that Well 2 exhibited a state of increasing reservoir permeability, or was closer to a bilinear flow regime, suggesting a relatively well-developed fracture network and more favorable initial flow behavior. In contrast, the other three wells may have experienced fracture closure due to stress sensitivity or inadequate proppant placement, leading to a perceived decline in permeability during the initial flow period.

4.3 Calculation of fracture volume loss ratio

It is generally accepted that the flowback process concludes when the reservoir pressure declines to the magnitude of the fracture closure stress^[31]. For multi-stage fractured horizontal wells, given the minimal horizontal stress anisotropy within the target interval, the average minimum horizontal stress is employed to estimate the fracture closure stress. Additionally, considering the presence of proppant within the fractures, experimental evidence indicates that the net stress exerted on the proppant typically ranges between 500 psi and 1000 psi. Accordingly, based on the requirements, the range of fracture closure stress is determined to be between ($S_{min} - 1000$ psi) and S_{min} ^[34]. Consequently, the time range for the flowback period can be established based on the pressure range. Through analysis of the decline trend during the flowback period, the semi-log plots of daily fluid production versus cumulative fluid production for the four wells at Platform C generally exhibit a harmonic decline trend, which satisfies the prerequisite conditions for fracture calculation.

Table 4 Estimated fracture closure pressure of four wells in Platform C				
Well	1	2	3	4
Frature closure pressure /MPa	72.11-75.56	68.81-72.26	72.31-75.76	73.61-77.06
Well bottom pressure when production /MPa	75.730	78.407	73.934	77.246

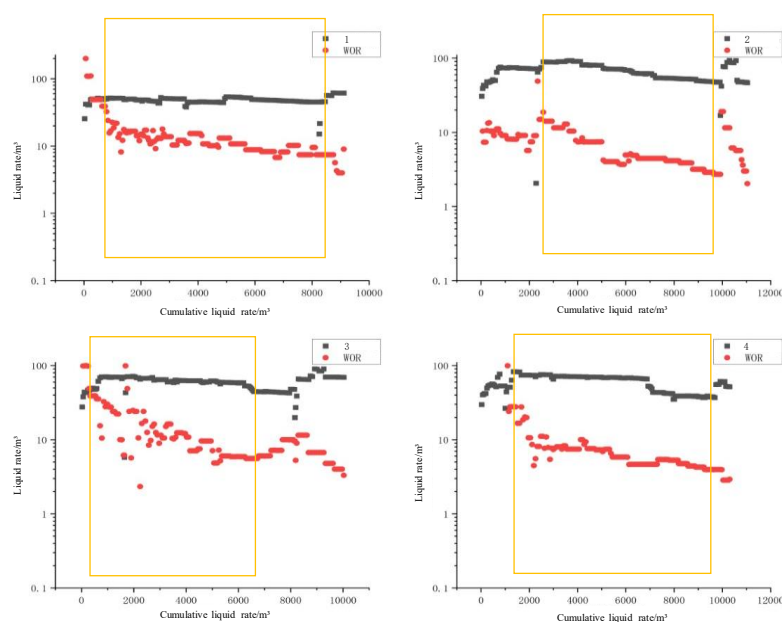


Figure 8 Semi-log diagram of liquid rate and cumulative liquid in Platform C

As illustrated in Figure 8, the initial fracture volumes for the four wells were determined through fitting and ranked as follows: Well 3 > Well 1 > Well 4 > Well 2. Notably, during the fracturing process of Well 3, significant intersection with natural fractures and fracturing interference were observed, while Well 4 exhibited minor interference. Consequently, the estimated initial fracture volumes for these two wells are relatively high.

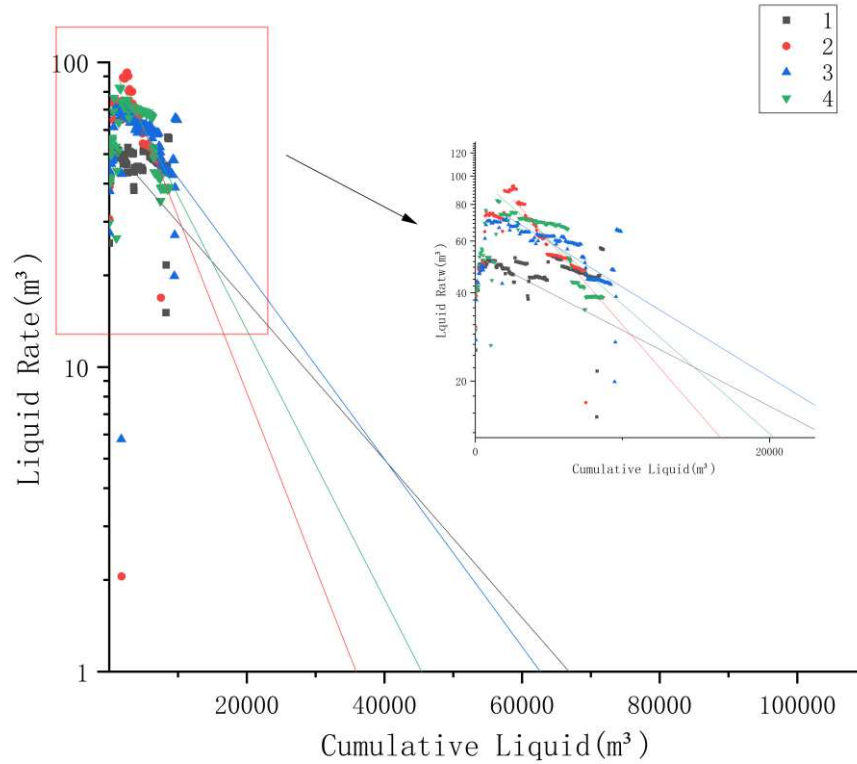


Figure 9 Initial Fracture Volume Fitting

According to the onsite PVT report of crude oil, the compressibility coefficient of oil in the study area is 13.866×10^{-4} (1/MPa), while the compressibility coefficient of fracturing fluid is approximately taken as that of water, 1×10^{-5} (1/MPa)^[35]. The fracture compressibility coefficient is primarily obtained through correlation charts.

By calculating the effective fracture volume and comparing it with the initial fracture volume, the fracture volume loss ratio was obtained. Well 4 exhibited the highest fracture loss ratio, followed by Well 2. Well 3 was excluded from consideration due to anomalies in its calculated fracturing fracture volume resulting from intersecting natural fractures. In conjunction with the opening pressure analysis of each well, it was observed that neither Well 2 nor Well 4 were opened under the predicted fracture closure pressure. This indicates that at the time of well opening, both wells were in a state of fluid communication with propped fractures, leading to unstable proppant packs. Consequently, inadequate proppant placement occurred during the production phase, resulting in a high fracture loss ratio.

Table 5 Fracture volume and fracture volume loss ratio of each well

Well name	m	Vf/m ³	Vf0/m ³	Loss ratio
1	0.00246	59080.1	66836.6	11.61%
2	0.00337	29287.92	35884.04	18.38%
3	0.00287	61527.51	62656.35	1.80%
4	0.00407	30314.23	45406.89	33.24%

5. Production decline analysis

Production data corresponding to the boundary-dominated flow regime, identified through flow regime analysis, were utilized to perform various decline curve analyses to obtain estimates of Estimated Ultimate Recovery (EUR) and initial decline rate for each well. The stimulation effectiveness of individual wells was then evaluated based on their EUR.

Traditional decline curve analysis is not directly applicable to shale oil reservoirs. Furthermore, due to the relatively idealized assumptions of the Duong decline model, its estimates tend to be lower than the actual values. Conversely, the multi-segment method, which divides the production profile into different flow stages and applies models such as Arps or Duong for fitting, yields the most appropriate interpretation parameters for each segment^[36]. However, this method often results in overestimation. Consequently, a more accurate EUR estimate is considered to lie between the values obtained from the Duong and multi-segment methods

Table 6 Decline analysis and decline ratio

Well name	DUONG method EUR (25years) m ³	Multi segment method EUR (25years) m ³	Decline ratio %
1	11830	11286	51.527
2	20935	23258	32.688
3	18829	20516	31.334
4	14598	16210	29.022

In terms of single-well EUR and decline performance, Well 2 exhibited the best productivity among the four wells, followed by Well 3. Well 1 displayed the poorest performance, characterized by a rapid production decline rate. Based on the preceding analysis, this underperformance of Well 1 is attributed to its excessively large initial

fracture volume coupled with an extended pressure control period. This combination likely hindered effective fracturing fluid leak-off into the reservoir matrix, resulting in inefficient oil-water displacement.

6. Discussion

Integrated analyses of soaking pressure decline and production data (Table 7) indicate that the geometric complexity of the fracture network serves as the core controlling factor for fracture system stability; however, the effectiveness of the fracture system, in conjunction with fracture scale, collectively determines the ultimate development outcome.

Table 7 Summary of analytical results

	Well name	1	2	3	4
Fracture features through well killing	Half-length of the main fracture	B	A	C	D
	Density of the secondary fractures	C	B	A	D
	Permeability of secondary fractures	B	C	D	A
	Width of the secondary fractures	—	—	—	—
Flow regime	Oil content in the matrix	A	B	C	D
	Slope of linear flow	0.75	0.47	0.71	0.65
Calculation of fracture volume	Initial fracture volume/m ³	66836.6	35884.04	62656.35	45406.89
	Fracture volume loss ratio/%	11.61%	18.38%	1.80%	33.24%
Production analysis	Decline ratio/%	51.527	32.688	31.334	29.022

Note: A, B, C, and D represent the magnitude of characteristic parameters, with A being the largest and D the smallest.

Well 1 exhibits the optimal oil-bearing index (A) with an initial fracture volume of 66,836.6 m³; however, its secondary fracture density is rated only as C, indicating a

fracture network dominated by primary fractures with relatively insufficient development of secondary fractures. Although the fracture loss ratio is controlled at a moderate level of 11.61%, its production decline rate reaches as high as 51.53%, the highest among the four wells. This phenomenon can be attributed to the simple fracture network dominated by primary fractures, which is more susceptible to proppant embedment and localized failure under closure stress, leading to rapid conductivity decay.

Well 2 exhibits relatively balanced indicators across all parameters, with secondary fracture density and width rated as B and C respectively, favorable oil-bearing properties (B), a fracture loss ratio of 18.38%, and a decline rate of 32.69%.

Well 3 presents distinctive fracture response characteristics: its secondary fracture density receives the highest rating (A), accompanied by a substantial initial fracture volume (62,656.35 m³) and the lowest fracture loss ratio among the four wells at merely 1.80%. The linear flow slope of 0.71 closely approaches the theoretical linear flow value. Comprehensive evaluation suggests that this well has developed a complex fracture network dominated by narrow fractures, achieving favorable proppant placement effectiveness with minimal fracture closure and conductivity loss.

Well 4 ranks lowest across all indicators: primary fracture half-length, secondary fracture density, and oil-bearing index are all rated as D, with a relatively small initial fracture volume (45,406.89 m³) and the highest fracture loss ratio reaching 33.24%. The fracture system efficiency in this well is severely compromised, characterized by inadequate fracturing fluid displacement and a critically low proportion of effective fracture volume.

Based on the above analysis, two key insights can be summarized: (1) The fracture loss ratio exhibits a negative correlation with the degree of secondary fracture development, as complex fracture networks effectively disperse closure stress and mitigate proppant failure progression; (2) The relationship between fracture loss ratio and production decline rate is not simply monotonic—wells with low loss ratios (such as Well 3) can maintain moderate decline levels; however, wells with large initial fracture volumes and favorable oil-bearing properties (such as Well 1), despite moderate loss ratios, may sustain high production rates while warranting close attention to their rapid decline risk.

7. Conclusion

Hydraulic fracturing is a pivotal technology for the development of horizontal wells in unconventional reservoirs, where the scale and effectiveness of the fracture network directly determine single-well productivity. Based on post-fracturing pressure decline analysis, flow regime identification, and fracture volume calculations, this study has yielded the following insights:

1. Under identical stratigraphic conditions, the scale of fracturing operations significantly influences fracture network propagation, with larger treatment scales generally resulting in larger fracture volumes.

2. Due to the pronounced heterogeneity and high stress sensitivity of unconventional reservoirs, the characteristic half-slope signature of the linear flow regime on diagnostic plots is often indistinct. However, analyzing the deviation of the slope from 0.5 enables a qualitative assessment of the initial fluid flow behavior: a slope less than 0.5 indicates relatively favorable permeability and smoother fluid flow, whereas a slope greater than 0.5 suggests poorer permeability and restricted flow pathways.

3. The early flowback stage can be approximated as a conventional decline period, during which the fluid produced from the fractures is predominantly water. By calculating the initial fracture volume and the effective fracture volume based on the material balance principle, the fracture loss ratio during the flowback period can be determined. Analysis indicates that fractures inadequately propped during the soaking period are prone to closure during flowback, leading to an increased fracture loss ratio. Conversely, an excessively large initial fracture volume implies prolonged retention of fracturing fluid in the formation, adversely affecting oil-water displacement efficiency and subsequent productivity.

4. The fracture loss ratio exhibits a negative correlation with the degree of secondary fracture development; however, it does not show a clear linear relationship with productivity. This suggests that while fracture characteristics provide the foundation for productivity potential, the ultimate development outcome remains significantly influenced by the rationality of the post-fracturing production scheme.

5. Based on these insights, it is recommended that horizontal well fracturing designs incorporate large-scale treatments within engineering feasibility limits, coupled with adequate soaking time. Furthermore, regarding the production scheme, ensuring the well is not opened until the reservoir pressure has declined to a level where the

fractures are adequately propped can help reduce the fracture loss ratio, thereby achieving more favorable productivity performance.

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CONFLICT OF INTEREST

The authors have no conflicts to disclose.

DATA AVAILABILITY

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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Appendix A Derivation of the slope of unconventional reservoir flow characteristics

Assuming that the seepage of a single-phase liquid in a homogeneous medium follows the linear seepage law, both the porous medium and the liquid are micro-compressible, and the entire flow process is an isothermal unstable seepage.

The unstable seepage equation for a single-phase compressible liquid derived based on seepage mechanics is as follows:

$$\nabla^2 p = \frac{1}{\eta} \frac{\partial p}{\partial t} \quad (1)$$

$$\eta = \frac{k}{\phi_o \mu C_t} \quad (2)$$

Where, p —Pressure, Pa;

η —Pressure transmission coefficient;

k —Permeability, $10^{-3} \mu m^2$;

μ —Fluid viscosity, $mPa \cdot s$.

C_t —Total compression coefficient, MPa^{-1} .

From a one-dimensional perspective, the seepage equation is:

$$\frac{\partial^2 p}{\partial x^2} = \frac{1}{\eta} \frac{\partial p}{\partial t} \quad (3)$$

It can also be understood as an ideal one-dimensional diffusion equation, with the boundary conditions being:

$$\begin{cases} x \geq 0; p(x, 0) = p_i \\ x = 0; p(0, t) = p_{wf} \end{cases}$$

By means of variable substitution and Laplace integral transformation, the final similar solution is obtained as follows:

$$p(x, t) - p_i = (p_{wf} - p_i) \operatorname{erfc} \left(\frac{x}{2\sqrt{\eta t}} \right) \quad (4)$$

In the formula, erfc represents the complementary error function, $\operatorname{erfc}(x) = \frac{2}{\sqrt{\pi}} \int_x^\infty e^{-y^2} dy$.

Since the early linear flow stage mainly involves the production through fractures, the total output is equal to the reservoir area multiplied by the unit area of the fractures. In this case, the surface flux is used for calculation.

According to Darcy's law, combined with formula (4), the unit area surface flux of the fractures is:

$$j(t) = -\frac{\mu}{k} \frac{\partial p}{\partial x} \Big|_{x=0} = -\frac{k}{\mu} \frac{(p_{wf} - p_i)}{\sqrt{\pi \eta t}} \quad (5)$$

Cumulative production is:

$$q(t) = Aj(t) = A \frac{k}{\mu} \frac{(p_i - p_{wf})}{\sqrt{\pi \eta t}} = A \frac{(p_i - p_{wf})}{\sqrt{\pi}} \sqrt{\frac{k}{t \phi_o \mu C_t}} \quad (6)$$

And the normalized production volume $RNP = \frac{(p_{wf} - p_i)}{q(t)}$, so the RNP is proportional to the $\sqrt{t}$. While MBT is proportional to time t , thus on the double-logarithmic graph of RNP vs MBT, the slope of the conventional linear flow shows a standard trend of 0.5

For unconventional reservoirs, with their strong heterogeneity and stress sensitivity, the η coefficient in the diffusion equation is not a constant. In unconventional reservoirs, the pressure conductance coefficient η is defined as:

$$\eta(t) = \frac{k(t)}{\phi_o \mu(t) C_t(t)} \quad (7)$$

Make $\tau(t) = \int_0^t \eta(\xi) d\xi$, Substituting into equations (7) and (3), we obtain:

$$\frac{\partial^2 p}{\partial x^2} = \frac{\partial p}{\partial \tau} \quad (8)$$

Using the same calculation method as in the previous text, the final result for the production of the diffusion equation for unconventional reservoirs is:

$$q(t) = Aj(t) = A \frac{k(t)}{\mu(t)} \frac{(p_i - p_{wf})}{\sqrt{\pi \tau(t)}} \propto \frac{k(t)}{\mu(t) \sqrt{\tau(t)}} \quad (9)$$

Make $\frac{k(t)}{\mu(t)} = M(t)$, Assuming that the reservoir permeability changes over time according to a power law $M(t) = M_0 t^{-\beta} (\beta \neq 1)$, and the porosity and compressibility are constants, then:

$$\tau(t) = \int_0^t \eta(\xi) d\xi = \int_0^t \frac{M_0 \xi^{-\beta}}{\phi_o C_t} d\xi = \frac{M_0}{\phi_o C_t} \int_0^t \xi^{-\beta} d\xi = \frac{M_0}{\phi_o C_t} \frac{t^{1-\beta}}{1-\beta} \quad (10)$$

So,

$$q(t) \propto \frac{k(t)}{\mu(t) \sqrt{\tau(t)}} \propto t^{-\frac{1+\beta}{2}} \quad (11)$$

The accumulated total obtained from the points is

$$N_p(t) = \int_0^t q(\tau) d\tau \propto t^{\frac{\beta-1}{2}} \quad (12)$$

$$RNP = \frac{(p_{wf} - p_i)}{q(t)} \propto t^{\frac{1+\beta}{2}} \quad (13)$$

$$MBT = \frac{N_p(t)}{q(t)} \propto t^\beta \quad (14)$$

Therefore, the slope on the flow pattern judgment diagram:

$$m = \frac{dLn(RNP)}{dLn(MBT)} \propto \frac{1 - \beta}{2} \quad (15)$$