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New Method for Capacity Evaluation of Offshore Low-Permeability Reservoirs with Natural Fractures

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Abstract: In recent years, the development of two offshore low-permeability oil fields has revealed unexpected challenges. The actual productivity of these fields significantly deviates from the designed capacity. Some wells even outperform the expectations for low-permeability limestone fields. This discrepancy primarily stems from a lack of accurate understanding of natural fractures before and after drilling, resulting in substantial errors in capacity assessment. This paper addresses these challenges by proposing a new production capacity model and evaluation method for both vertical and horizontal wells in low-permeability limestone reservoirs. The method leverages logging curve data, incorporating vertical gradation and fractal analysis to effectively represent the fracture's complexity and connectivity. It uniquely considers factors such as fracture fractal dimensions, threshold pressure, and stress sensitivity, significantly enhancing prediction accuracy. Furthermore, by analyzing the longitudinal gradient in logging curves, the method effectively identifies strong heterogeneity, leading to more accurate capacity evaluations in actual fields. The results demonstrate that our model reduces the average prediction error to less than 15%, markedly outperforming traditional methods. Calculation results of the newly developed capacity formula align closely with actual production data and tracer test results, showcasing its practical applicability and potential for widespread use. This study notably advances the evaluation of reasonable production capacity in similar offshore reservoirs.

Keywords: offshore low-permeability reservoirs; natural fractures; fractal parameters; capacity evaluation; threshold pressure gradient

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1. Introduction

Oil and gas resources play an important role in global energy. As conventional oil and gas fields gradually deplete, offshore low-permeability reservoirs are gaining industry attention for their significant development potential [1]. Despite years of development, these reservoirs remain under-exploited. Capacity evaluation of offshore low-permeability reservoirs faces challenges due to high drilling costs, limited production wells, and a complex subsurface environment. The notable discrepancy between predicted and actual capacities in these oil fields presents development challenges. Effective capacity evaluation of directional and horizontal wells in reservoirs with natural fractures is vital for enhancing reserves and achieving rational, efficient development.

Taking two typical low-permeability oil fields in the offshore FA region as examples, the production capacity, according to the conventional Darcy formula, is proportional to the flow coefficient and differential pressure. However, this formula fails to explain certain anomalies. First, the low-permeability limestone Zone A in the FA15 field has a lower flow coefficient than the FA14 field, yet its production capacity exceeds FA14 by more than six times. Second, although Zone A has lower flow coefficient and production differential pressure than Zone B, their production capacities are nearly the same. Analyzing the reasons, it is concluded that the low-permeability limestone Zone A in the FA15 field developed natural fractures making a significant contribution to production capacity, which is confirmed by imaging logging and tracer tests. Therefore, conventional capacity models are unsuited for the capacity prediction of this type of reservoir. This highlights the importance of accurately characterizing permeability and capacity in low-permeability reservoirs with natural fractures, which forms the basis of this study.

Many scholars [2–5] have conducted a lot of research on capacity forecasting and evaluation. There are four main types of methods for capacity forecasting. The first is the method based on statistical analysis [6–9], which uses historical data and techniques such as trend analysis to predict future capacity through data analysis and modelling. It typically requires a substantial amount of high-quality data, making it unsuitable for early capacity assessments, especially in scenarios with limited data. The second is the empirical equation-based approach [10–12], which uses correlation equations to extrapolate future capacity based on past experience and observations. The currently widely used empirical analysis method is the modified Arps decreasing curve, which has a large error. The third is the analytical or semi-analytical capacity model [13–15] based on physical assumptions, which is derived with rigorous ideas, but the current model cannot reasonably characterize the actual seepage characteristics of heavy oil reservoirs, and it is more difficult to apply at the mine site. The fourth is the simulation-based method [16,17], usually using numerical simulation software to predict the production capacity. This method can consider the effects of multiple factors on the production capacity, but it depends on the computational power, model accuracy, and input data accuracy, which is relatively cumbersome. These methods have also achieved some results in practical applications, but they also have obvious limitations. In addition, for offshore low-permeability reservoirs with strong heterogeneity and natural fractures, there are relatively few studies on capacity evaluation, and a large number of scholars refer to the Jubilee formula [18] for capacity calculation. Under the influence of sedimentation, diagenesis, and tectonic movement, natural fractures in offshore low-permeability limestone reservoirs are more developed, and the presence of fractures improves the physical properties of the reservoir and increases the production capacity of oil wells. The production of oil wells is related to the fracture development degree, and there is no good solution internationally on how to quantitatively describe the relationship between natural fractures and oil well production. The development of low-permeability reservoirs generally requires fracturing construction operations, and there are many production formulas [19–22] corresponding to them. Although these production capacity formulas take into account the threshold pressure gradient or fracture conductivity, none account for natural fracture. Due to the lack of comprehensive consideration of the seepage characteristics (fractal characteristics of natural fractures, threshold pressure, and stress sensitivity) and the refined consideration of the strong longitudinal heterogeneity, existing capacity models cannot well reflect the interference caused by the longitudinal permeability gradient. It leads to a capacity model that cannot better reflect the actual seepage characteristics of the reservoir, and the limitations of the model lead to the inability to accurately predict the capacity of vertical and horizontal wells in this type of reservoirs.

Targeting the unique offshore geological structures and complex fluid dynamics, traditional capacity evaluation methods show clear limitations in such reservoirs. This study systematically examines how natural fractures affect the capacity of low-permeability reservoirs. Utilizing actual drilling data, it highlights the stark differences between pre-drilling models and actual post-drilling fracture distributions. These differences challenge the efficacy of traditional models and underscore the need for new evaluative approaches.

Based on the above considerations, a novel capacity evaluation model is proposed in this study, which incorporates the theory of fractal geometry for rational characterization of natural fractures based on the traditional theory, and introduces the fractal dimension

D and the connectivity coefficient θ to represent the permeability behavior of the fracture network more realistically. Additionally, in order to more finely characterize the strong longitudinal heterogeneity, the longitudinal heterogeneity based on the logging curves is considered in this paper. In the end, in order to improve the accuracy of production capacity prediction of low-permeability reservoirs with natural fractures, a new production capacity model that comprehensively considers the influence of fracture fractal, longitudinal heterogeneity, threshold pressure, and stress sensitivity is established in this paper, which forms a new production capacity evaluation method to provide a reference for the development of the same type of reservoirs. The new production capacity evaluation method proposed in this study which combines seepage and geological characteristics of offshore low-permeability reservoirs with developed natural fractures can provide theoretical guidance for the formulation of reasonable development technology policies of early project development.

2. Materials and Methods

2.1. Degree of Fracture Development and Fractal Dimension

A fractal is a form in nature in which the local and the whole are similar in some way [23]. The complexity of a fractal can be described quantitatively by the size of the fractal dimension, which is denoted by the letter D.

Before applying fractal theory, it should be judged first whether the distribution of the research object has fractal characteristics. For example, when studying the reservoir fractures, the grid coverage method is used on the core to judge whether the reservoir fractures conform to fractal characteristics. The specific method is as follows. First of all, cover the core profile with a square grid of side length r, then count the number of grids containing fractures $N(r)$. Secondly, change the scale of r, count the corresponding $N(r)$ values, and analyze the statistical data by least squares regression analysis in the double logarithmic coordinate system.

Research shows that there is a linear relationship between lg$N(r)$ and lg$r$. Therefore, the distribution of reservoir fractures has fractal characteristics, so the fractal dimension D can be used to quantitatively characterize the degree of fracture development. Some scholars have studied the relationship between fractal dimension and natural fracture density and found that the two satisfy certain quantitative relationships [24,25], which can be expressed as Equation (1):

$$s = f(D), \tag{1}$$

where s is the natural fracture density, $1/\text{cm}$; D is the fractal dimension.

In general, the higher the value of D, the greater the natural fracture density and the more developed the natural fractures are in relative terms. For cores, the grid coverage method can be used to determine the value of D. There are many methods to calculate the fractal dimension, of which the most commonly applied is the box-counting dimension method [26,27], obtaining the box-counting dimension by processing the image and then fitting the function using the least squares method. Therefore, the fractal dimension of the fracture network can be obtained by the box-counting dimension method after obtaining the shape of the fracture network based on the inversion of microseismic data [28].

2.2. Formations Consideration of Natural Fracture Evolution in Low-Permeability Reservoir Capacity Modeling

2.2.1. Permeability Characterization of Natural Fracture Networks

In this paper, fractal theory is introduced to characterize the permeability of the natural fracture network, considering the stress-sensitive properties of the fracture network. Considering the wellbore and surrounding natural fractures in a reservoir can connect to form a dominant seepage channel, this indicates that the closer from the wellbore it is, the greater the total permeability of the reservoir. Based on earlier studies [29,30], the fractal permeability of natural fractures considering the stress sensitivity can be obtained as shown in Equation (2).

$$k = k_{iT}\left(\frac{r}{r_w}\right)^{n'} e^{-\beta_k(p-p_w)}, \quad (2)$$

where $n' = -(D-2-\theta)$, k_{iT} is the initial total permeability of natural fractures, darcy; β_k is reservoir pressure sensitivity coefficient, MPa^{-1}; θ is anomaly diffusion coefficient, which indicates the connectivity of the fractal network (the smaller θ is, the better the connectivity of the network); p is the formation pressure, MPa; and p_w is the pressure at the reference point, MPa; r is the radial distance between the wellbore and the volume node of the fluid storage space unit in a medium containing natural fractures, m; r_w is the radial distance between the wellbore and the selected reference point position, m.

It is generally accepted that a dual-media reservoir consists of two types of media, matrix blocks and fractures, and that these two media are equally distributed. If the fractures are sufficiently developed and the connectivity between the fractures is good, fluid flow will follow the seepage law of fluids in dual-media reservoirs, but in low-permeability reservoirs, the connectivity between natural fractures is poor, so low-permeability reservoirs with natural fractures cannot be considered dual-media reservoirs. Total reservoir permeability is not a simple superposition of matrix permeability and fracture permeability but is related to the degree of development of natural fractures. Based on the above understanding, combined with the fractal dimension, the formula for calculating the total permeability of a low-permeability reservoir considering natural fractures is established. It can be represented as Equation (3):

$$k_t = k_m + (D-2-\theta)k_f, \quad (3)$$

where k_m is matrix permeability, darcy; k_f is natural fracture permeability, darcy; k_t is total permeability of the reservoir, darcy. k_t is related to the size of D value. Usually, the D value of reservoir fracture is 2 to 3; when the D value is 2, the natural fracture of reservoir is not developed, k_t is equal to k_m, which is a single-medium reservoir. When the D value is 3, k_t is the sum of k_m and k_f, which is a double-medium reservoir. When the D value is between 2 and 3, the reservoir is in the transition zone from single-medium to double-medium. The value of D is given between 2 and 3 in this paper while considering the development of natural fractures in low-permeability reservoirs.

The development of natural fractures in low-permeability reservoirs increases the permeability of the reservoir, assuming that fluid flow in the fractures is between parallel flat plates [31], thus the permeability of natural fractures can be expressed as Equation (4):

$$k_f = 8.33 \times 10^{-6} s b^3, \quad (4)$$

where b is the average width of natural fractures, μm.

Combining Equations (2)–(4), the expression for permeability characterization of the reservoir considering natural fractures can be obtained as the Equation (5):

$$k = \left[k_m + 8.33 \times 10^{-6} s b^3 n\right] e^{-\beta_k(p-p_w)} \left(\frac{r}{r_w}\right)^{n'}, \quad (5)$$

where $n = D - 2 - \theta$.

2.2.2. Modeling of Production Capacity of Vertical Wells Containing Natural Fractures

Figure 1 shows a schematic diagram of a vertical well in an infinite formation. In this paper, the vertical well seepage process is considered as the radial flow from the reservoir supply boundary to the vertical wellbore.

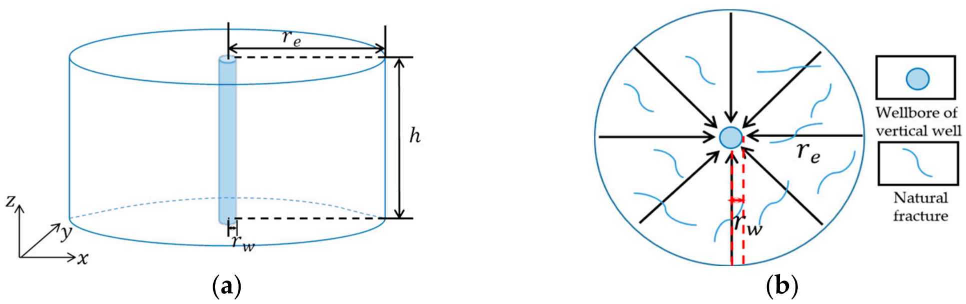

Figure 1. Physical model of the vertical well in low-permeability reservoir: (**a**) Schematic of a three-dimensional model of a vertical well; (**b**) Plane seepage pattern diagram of a vertical well.

The equation of motion for an offshore low-permeability reservoir considering the threshold pressure gradient is given as the Equation (6):

$$v = \frac{k}{\mu_{eff}}\left(\frac{\partial p}{\partial r} - G\right), \tag{6}$$

where μ_{eff} is the effective fluid viscosity, mP as; v is the seepage velocity, m/s; and G is the starting pressure gradient, MPa/m.

The above equation of motion comprehensively reflects the seepage characteristics of offshore low-permeability reservoirs, and the planar radial flow equation for vertical wells can be obtained as shown in Equation (7).

$$\frac{qB_o}{2\pi rh} = \frac{86.4}{\mu_{eff}}\left[k_m + 8.33\times 10^{-6} sb^3 n\right] e^{-\beta_k(p-p_w)}\left(\frac{r}{r_w}\right)^{n'}\left(\frac{\partial p}{\partial r} - G\right), \tag{7}$$

where q is the production rate, m^3/d; B_o is the crude oil volume factor; h is the effective thickness of the reservoir, m.

Introduce $\zeta = e^{\beta_k p}$, $\zeta_i = e^{\beta_k p_e}$, and let $n = D - 2 - \theta$, $\Omega = \frac{qB_o}{2\pi h}\frac{\mu_{eff}\beta_k r_w^{n'}\zeta_i}{86.4(k_m + 8.33\times 10^{-6} sb^3 n)}$, from Equation (7), we can obtain the Equation (8) by simplification:

$$\frac{d\zeta}{dr} - \beta_k G\zeta - \frac{\Omega}{r^{n'+1}} = 0, \tag{8}$$

where ζ is the introduced pressure transformation coefficient; ζ_i is the corresponding pressure transformation coefficient at the supply boundary $r = r_e$; and Ω is the integrated reservoir parameter used for simplification.

Equation (8) is a typical first-order nonlinear differential equation, ζ is expressed as Equation (9):

$$\zeta = e^{\beta_k Gr}\left(\int e^{-\beta_k Gr}\cdot\frac{\Omega}{r^{n'+1}}dr + C\right). \tag{9}$$

Since $\beta_k G << 1$, $(\beta_k G)^2 << 1$, substituting into Equation (9), we can obtain Equation (10):

$$\zeta = e^{\beta_k Gr}\left(-\frac{\Omega}{n'}\frac{e^{-\beta_k Gr}}{r^{n'}} + C\right). \tag{10}$$

When $r = r_e$, $\zeta_i = e^{\beta_k p_e}$, based on Equation (10), we can obtain Equation (11):

$$C = \left(\zeta_i + \frac{\Omega}{n'}\frac{1}{r_e^{n'}}\right)/e^{\beta_k Gr_e}. \tag{11}$$

Combining Equations (10) and (11), the constant term can be eliminated, and Equation (12) can be derived:

$$\xi = -\frac{\Omega}{n'}\frac{1}{r^{n'}} + \left(\frac{\Omega}{n'}\frac{1}{r_{\mathrm{e}}^{n'}} + \xi_{\mathrm{i}}\right)e^{\beta_k G(r - r_{\mathrm{e}})}. \tag{12}$$

To obtain an expression for the capacity, isolating Ω, and we can acquire Equation (13):

$$\Omega = \frac{\left[\zeta - \zeta_i e^{\beta_k G(r - r_e)}\right] n'}{\left[\frac{e^{\beta_k G(r - r_e)}}{r_e^{n'}} - \frac{1}{r^{n'}}\right]}. \tag{13}$$

The express Ω in Equation (13) is related to the production capacity, thus further deriving the production capacity equation for vertical wells in low-permeability reservoirs with natural fracture, as shown in Equation (14):

$$q = 86.4\frac{2\pi h}{B_{\mathrm{o}}}\left\{\frac{\left(k_m + 8.33 \times 10^{-6} s b^3 n\right)\left[e^{-\beta_k[(p_{\mathrm{e}} - p_{\mathrm{w}}) - G(r_{\mathrm{e}} - r_w)]} - 1\right]}{\mu_{eff}\beta_k\left[\frac{1}{n'}\left(\frac{r_w}{r_e}\right)^{n'} - \frac{e^{\beta_k G(r_{\mathrm{e}} - r_w)}}{n'}\right]}\right\}, \tag{14}$$

where p_w is the bottomhole pressure of the vertical well, MPa; p_e is the reservoir pressure, MPa.

In the above equation, $n = D - 2 - \theta$, when $D = 2$ and $\theta = 0$, then $n = 0$, indicates a single pore medium. As a result, Equation (14) becomes the capacity equation of a single pore medium considering only the threshold pressure and stress sensitivity. When G and β_k converge to 0, Equation (14) can be transformed into the commonly used Joshi equation [32]. When $D = 3$, $\theta = 1$, then $n = 0$, similar to the single medium, indicates that despite the development of fractures, the natural fractures are mainly developed as isolated seams without good connectivity, and the contribution to the capacity remains negligible. When $D = 3$, $\theta = 0$, then $n = 1$, indicating that the fractures are more developed, the connectivity between the fractures is good, which can improve the physical properties of the reservoir and have a greater contribution to the production capacity. Equation (14) demonstrates the contribution of the fracture development degree and fracture connectivity to the production capacity. The traditional method is difficult to well characterize the permeability of the fracture, and the matrix permeability is usually used to calculate the production capacity, which leads to a pessimistic assessment of the production capacity of low-permeability reservoirs containing natural fractures. The method in this paper can better characterize the production capacity of low-permeability reservoirs with developed natural fractures.

At present, offshore oil fields are still developed with directional wells due to the large number of longitudinal layers as well as economic considerations. But low-permeability reservoirs tend to exhibit strong heterogeneity in the longitudinal direction. In order to accurately characterize this heterogeneity, a production capacity method combined with logging curve analysis based on Equation (14) is proposed. In this method, a logging point is set every 0.125 m on the logging curve, and the production capacity calculated from each logging point is superimposed. Due to the certain similarity between the differential equation of seepage of porous media in reservoirs and the differential equation of electric charge flow through conductor materials, the reservoir production capacity can be solved in parallel using the hydroelectric similarity principle [33], which can effectively show the effect caused by the longitudinal physical property grade difference.

The indoor experimental evaluation method has been used by previous researchers [34], who conducted an experimental analysis of drilling-fluid-contaminated core to quantify the effect of drilling fluid on production capacity, and concluded that the effect of drilling fluid contamination on production capacity is large and non-negligible. In this study, the epidermal coefficient was introduced to account for drilling fluid contamination, and we can obtain the Equation (15):

$$Q = \sum_{\mathrm{j}=1}^{N} q_{\mathrm{j}} = \sum_{\mathrm{j}=1}^{N} 86.4 \frac{2\pi h_j}{B_{\mathrm{o}}} \left\{ \frac{\left(k_{mj} + 8.33 \times 10^{-6} s b^3 n\right) \left[e^{-\beta_{kj}[(p_{\mathrm{e}} - p_{\mathrm{w}}) - G_j (r_{\mathrm{e}} - r_w)]} - 1 \right]}{\mu_{eff} \beta_{kj} \left[\frac{1}{n'} \left(\frac{r_w}{r_e} \right)^{n'} - \frac{e^{\beta_{kj} G_j (r_{\mathrm{e}} - r_w)}}{n'} + S \right]} \right\}, \quad (15)$$

where Q is the final calculated production rate, m^3/d; q_j is the calculated production rate at logging point j, m^3/d; h_j is the effective thickness at logging point j (0.125 m in this paper), m; G_j is the threshold pressure gradient at logging point j, MPa/m; β_{kj} is the stress sensitivity factor at logging point j, 1/MPa; K_{mj} is the initial permeability at logging point j (generally based on the interpreted permeability on the logging curve), darcy; r_{w} is the wellbore radius, m; S is the skin factor, dimensionless.

Equation (15) is the production capacity equation for offshore low-permeability reservoirs considering the effects of fractal natural fracture, longitudinal heterogeneity, threshold pressure gradient, stress sensitivity, and skin factor.

The laboratory results show that there is an exponential relationship between the threshold pressure gradient and the measured fluid permeability of the low-permeability reservoirs in the study area, which can be characterized by Equation (16):

$$G = 0.0755 K_{mj}{}^{-1.006}. \quad (16)$$

The stress sensitivity coefficients were obtained from the core experiments in the study area, and the experimental results showed that the correlation between stress sensitivity coefficients and the permeability was good, which can be expressed by Equation (17).

$$\beta_k = 0.007 K_{mj}{}^{-0.25}. \quad (17)$$

When the average permeability interpreted from logging is used to directly evaluate the production capacity, it cannot well reflect the inhibiting effect of longitudinal physical property differences on the production capacity, which often leads to large errors in the production capacity prediction results. Applying the new capacity formula derived in this paper to calculate the capacity of each measurement point based on the relevant parameters can effectively characterize the contribution of the natural fracture development degree, fracture connectivity, and strong reservoir longitudinal heterogeneity to the capacity of low-permeability reservoirs, which is more in line with the seepage laws and characteristics of this type of reservoir, and is of better value for popularization and application in the evaluation of capacity.

In the calculation process of this method, it is necessary to obtain the data of a single well logging curve; at the same time, the selection of other parameters also has some influence on the results of capacity evaluation. In order to improve the operability of the method, it is necessary to explain how some parameters are taken: ① permeability is mainly based on the results of the well logging interpretation of each measurement point and the results of the well logging interpretation of core calibration; ② the threshold pressure gradient and stress sensitivity coefficient are mainly obtained by combining the regional characteristics of the offshore oil field with the results of core experiments; ③ the supply radius and skin coefficient are determined by the results of well test interpretation; ④ fluid viscosity and density are obtained from the results of oil sampling experiments.

2.2.3. Capacity Modeling of Horizontal Wells with Natural Fractures

Figure 2 is a schematic diagram of a horizontal well in an infinite formation in three-dimensional space. In this paper, the horizontal well seepage process is regarded as the proposed radial flow from the reservoir supply boundary to the horizontal wellbore. Based on the research results in the literature [35,36], the seepage field during the stable production of a horizontal well are divided into an external seepage zone in the *xy* plane and an internal seepage zone in the *xz* plane.

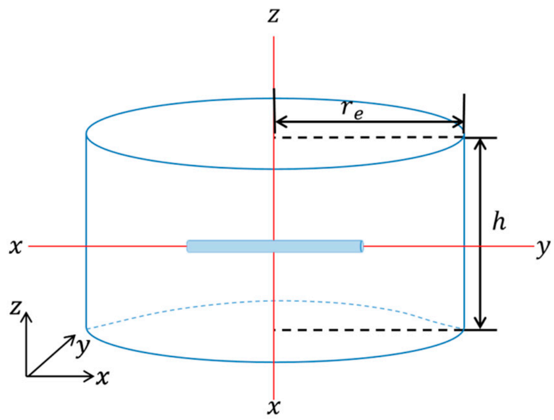

Figure 2. Three-dimensional view of horizontal wells in an infinity formation.

- *xy*-plane external seepage area

Figure 3 shows the 2D seepage pattern diagram of a horizontal well in *xy* plane. The fluid flows from the reservoir supply boundary to the reservoir surrounding horizontal well in a simulated planar radial flow. According to the principle of production equivalence [37], the horizontal section of the horizontal well can be regarded as a proposed circular production pit, then the planar radial seepage process of the fluid from the supply boundary to the proposed circular production pit in the horizontal section constitutes the external seepage field in the *xy*-plane.

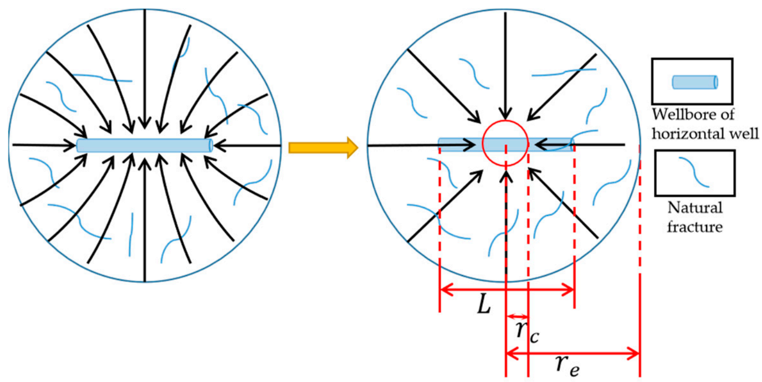

Figure 3. 2D xy-plane seepage pattern diagram for horizontal wells.

Considering the circular radius $h/2$ of the production pit space itself, and then according to the research results [32,38], the radius of the proposed circular production pit in the horizontal section is considered as Equation (18):

$$r_c = L/4 + h/2, \tag{18}$$

where L is the length of horizontal well section, m; h is the reservoir effective thickness, m.

- *xz*-plane internal seepage zone

Figure 4 shows the two-dimensional seepage pattern of the horizontal well in the *xz* plane. The fluid flows from the outer boundary of the proposed circular production pit of the horizontal section to the bottom of the horizontal well in a planar radial flow vertically and around the horizontal well section, and the flow process in this section constitutes the internal seepage field in the *xz*-plane.

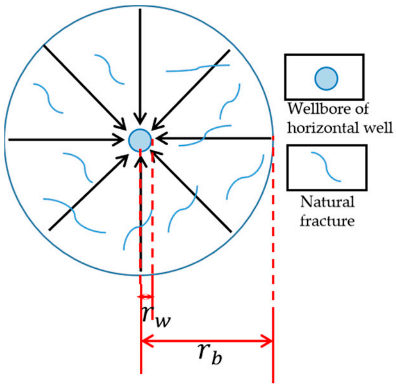

Figure 4. 2D xz-plane seepage pattern diagram for horizontal wells.

Since the internal seepage process occurs at a spatial height of reservoir thickness h, the seepage radius of the internal seepage zone can be expressed as Equation (19)

$$r_b = h/2. \tag{19}$$

- Horizontal well steady-state capacity equation

Considering the influence of fractal characteristics of natural fracture, threshold pressure gradient, stress sensitivity, and skin factor on the production capacity of low-permeability reservoirs, the derivation of the steady-state production capacity formula for horizontal wells is the same as that for vertical wells, except that the seepage process of horizontal wells is divided into two parts, the horizontal external seepage and the vertical internal seepage. Ignoring the repetition of the derivation process, the volume flows Q_1 and Q_2 are given for the horizontal external seepage region and the vertical internal seepage region of the horizontal well respectively, which can be expressed as Equations (20) and (21):

$$Q_1 = 86.4\frac{2\pi h}{B_o}\left\{\frac{\left(k_{mj} + 8.33\times10^{-6} s b^3 n\right)\left[e^{-\beta_{kj}[(p_e - p_w) - G_j(r_e - r_c)]} - 1\right]}{\mu_{eff}\beta_{kj}\left[\frac{1}{n'}\left(\frac{r_c}{r_e}\right)^{n'} - \frac{e^{\beta_{kj}G_j(r_e - r_c)}}{n'} + S\right]}\right\}, \tag{20}$$

$$Q_2 = 86.4\frac{2\pi h}{B_o}\left\{\frac{\left(k_{mj} + 8.33\times10^{-6} s b^3 n\right)\left[e^{-\beta_{kj}[(p_e - p_w) - G_j(r_b - r_w)]} - 1\right]}{\mu_{eff}\beta_{kj}\left[\frac{1}{n'}\left(\frac{r_w}{r_b}\right)^{n'} - \frac{e^{\beta_{kj}G_j(r_b - r_w)}}{n'} + S\right]}\right\}. \tag{21}$$

The capacity of the horizontal well is the sum of the volume flow rates in the horizontal external seepage zone and the vertical internal seepage zone, so the production capacity Equation (22) is obtained as follows.

$$Q' = Q_1 + Q_2. \tag{22}$$

3. Results

3.1. Example Applications

Section 3.1.1 mainly discusses the natural fractures in offshore low-permeability oil fields and highlights the limitations of conventional evaluation methods. It aligns with the main objectives of the study, emphasizing the need to improve capacity assessment methods in these oil fields.

Section 3.1.2 focuses on comparing and validating the proposed method against traditional evaluation methods in actual capacity assessment. The main discussion focuses on the practical application of the two well-type capacity formulas derived earlier. This part aligns with the study's main objectives, demonstrating the new method's superiority in enhancing accuracy in capacity evaluation, thereby highlighting how each section contributes towards achieving the overall research goals.

3.1.1. Overview of Foundations

Take the low-permeability limestone reservoir of the FA15 oil field in the eastern part of the South China Sea as an example. The reservoir of this oil field is vertically divided into two reservoir calculation units, the upper Zone A and the lower Zone B. Zone A is a localized point-reef deposition; the reservoir is extremely heterogeneous, and the lateral distribution of the reservoir is unstable compared to Zone B. The pre-drilling exploration well is considered to have undeveloped fractures, while the post-drilling well is considered to have more developed natural fractures (e.g., Figure 5). Figure 5 illustrates the more developed natural fractures around this well. The real drilling imaging logging shows that several development wells encountered high-angle fractures, and the fracture density is becoming lower in Zone A from top to bottom. The fracture in Zone B is slightly developed with a fracture dip over 80°, and the fracture in Zone A is more developed with a fracture dip over 80°. The reservoir parameters are shown in Table 1 as follows.

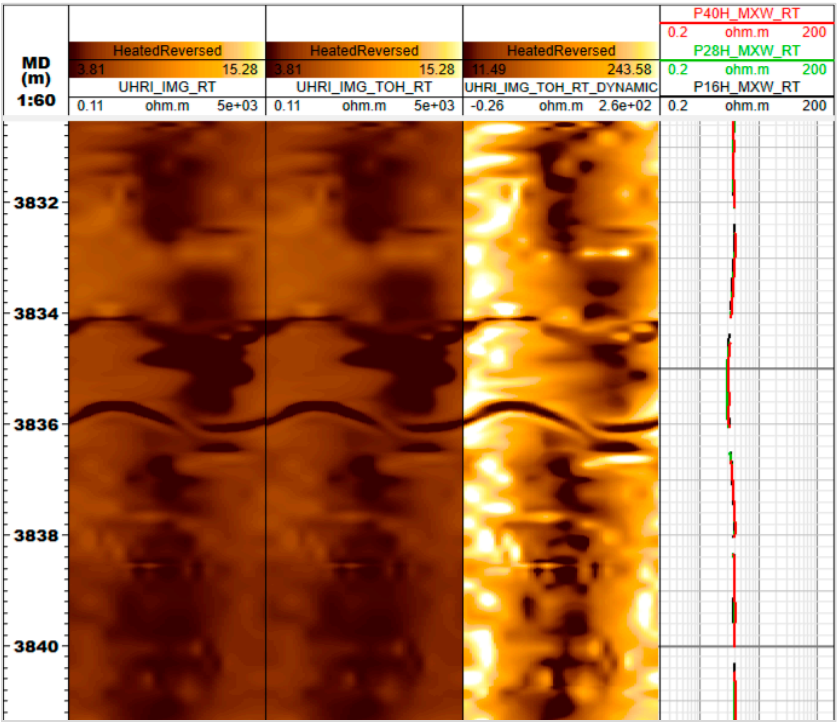

Figure 5. Horizontal section resistivity imaging logging with drilling identifies fractures.

Table 1. Basic reservoir parameters.

Parameters	Reservoir		Unit (of Measure)
	Zone A	Zone B	
Crude oil volume factor	1.041	1.041	-
Formation Crude Oil Viscosity	5.6	5.6	mPa·s
Effective reservoir thickness	4.9	5.7	m
Permeability of matrix block	0.0179	0.0412	darcy
Natural fracture density	0.006~0.0187	0.0005~0.001	1/cm
Average width of natural fracture	186~778	189	μm
Stress sensitivity factor	0.0016~0.0034	0.0012~0.0028	MPa^{-1}
Threshold pressure gradient	0.004145499	0.001792092	MPa/m
Initial formation pressure	17.970~18.511	17.970~18.511	MPa

The reservoir has a total of 11 development wells, including 9 production wells and 2 water injection wells, and the production capacity of each production well varies widely. In addition, the thickness of the reservoir drilled in Zone A is much thinner, the physical properties of the reservoir are not as expected, and the field is the first low-permeability limestone reservoir in the eastern part of the South China Sea with few analogue data. These differences in understanding before and after drilling and the lack of analogous data increase the difficulty of capacity evaluation. And the use of conventional capacity evaluation methods will lead to a large deviation in the capacity evaluation, which is not conducive to decision-making on the development plan.

3.1.2. Comparison and Validation of Capacity Forecasting Methods

A tracer test means injecting tracers into the reservoir, and the tracers are detectable substances. These substances then flow with the reservoir fluids, allowing their movement to be tracked. By monitoring the arrival and concentration of tracers in production wells, we gain insights into the fluid flow paths and the reservoir's heterogeneity, which is crucial for accurate capacity assessment.

The tracer test plays a crucial role in understanding fluid production profiles and contributes significantly to capacity evaluation. They offer unique insights into the movement and distribution of fluids within the reservoir, providing a more accurate assessment of the reservoir's production capacity. By analyzing tracer test data, we can better understand the dynamics of fluid flow and incorporate the understanding into our capacity evaluation models, thus enhancing the accuracy and reliability of the proposed capacity evaluation method.

Taking the X well as an example, the length of the horizontal section drilled is 1362 m, of which Zone B is drilled for 1120 m and Zone A is drilled for 242 m, and the actual initial production is 142 m^3/d. In order to better understand the well capacity, the well was tracer tested. In order to effectively test the different sections of the fluid production profile, taking into account the properties of the reservoir and the pressure, the well was divided into four sections, and a packer was used between the sections to seal the well. The positions of the tracer in the horizontal section are shown in Table 2.

Table 2. Position of short sections of tracer.

Serial Number	Serial Number	Water-Soluble Tracer	Actual Lowering Position (m)		Permeability (mD)	Stratum (Geology)
1	ZFFA-SRT01	DWT-6	4050.8	4058.9	0.1–1	Zone A
2	ZFFA-SRT02	DWT-10	3570.5	3578.6	350–400	Zone B
3	ZFFA-SRT03	DWT-11	3248.5	3256.6	40–60	Zone B
4	ZFFA-SRT04	DWT-12	2786.3	2794.4	0.5–1	Zone A

Among them, section 4 was drilled in the stratigraphic section and encountered Zone A. Sections 2 and 3 were mainly drilled in Zone B, which had better physical characteristics. And section 1 was drilled in the end of the horizontal section encountering Zone A, which had poorer physical characteristics, but a large amount of leakage occurred in this section, confirming that the natural fracture was more developed. According to the conventional understanding and evaluation result of the capacity formula, the capacity should mainly come from sections 2 and 3, but the actual situation of the tracer shows that although the permeability of section 1 is 0.1–1 mD, section 1 has the largest contribution to the production of well X, which is 59.3%. However, Zone B with the permeability of 40–400 mD has a small contribution to the production of the X well of only 16.5%, as shown in Figure 6.

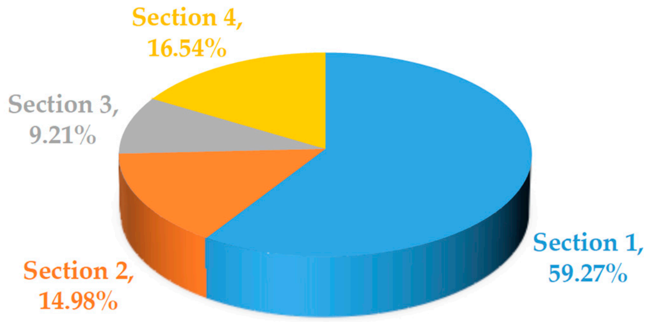

Figure 6. Cumulative percentage of oil production from each section of the tracer.

The tracer test results further confirm that the contribution of natural fractures to the well capacity should not be ignored. The existence of natural fractures leads to a larger overall permeability of the reservoir, and a higher contribution to the well capacity. The conventional production capacity formula with considering the permeability of the reservoir as a constant value of the permeability of the matrix does not meet the needs of capacity evaluation, and the new production capacity formula to consider the existence of natural fractures is more fit in the actual situation.

- Example application and verification of horizontal wells

This study introduces a groundbreaking capacity prediction model for offshore low-permeability reservoirs with natural fractures. Unlike traditional models, our approach innovatively considers the natural fracture development and connectivity, offering a more nuanced characterization of the total permeability of the reservoir. The model integrates key factors such as fractal dimensions, threshold pressure gradient, and stress sensitivity, providing a holistic view of reservoir dynamics.

Comparing the difference in capacity calculation between the method of this paper and the conventional method, taking well X as an example, the basic parameters of which are shown in Table 3. Substituting the drilling data of the X well into the capacity correction formula of Joshi [32], the calculated initial capacity is 72.79 m^3/d, of which the error is 48.7% compared with the well's actual capacity of 142 m^3/d. Substituting the actual drilling data of the X well into the new capacity formula of this paper, the calculated initial capacity is 148.9 m^3/d, and the error is only 5% compared with the actual capacity of 142 m^3/d of the well, which is highly accurate. It is analyzed and believed that the capacity contribution of the X well mainly comes from Zone A, and the Joshi formula is difficult to properly characterize the natural fracture permeability of Zone A. The new capacity formula has made great improvement in this aspect, which effectively reduces the capacity calculation error and confirms the reliability of the method promoted in this paper.

To further verify the accuracy and applicability of the method promoted in this paper, all other wells in the field were also calculated. There are a total of 9 production wells in this reservoir, and the capacity of the 9 wells is calculated respectively using the new method in this study and the conventional method, and the results are as shown in Table 4. In Table 4, error 1, 2, and 3 respectively represents the calculation error between Joshi correction formula [32], Chen formula [35], new capacity formula, and the actual production of the wells. It is known from the table, for horizontal wells, the calculation error of the Joshi correction formula is within 50%, and for multi-branch wells, the calculation error of the Joshi correction formula is 50~80%. For horizontal wells, the calculation error of the Chen formula is within 70%, and for multi-branch wells, the calculation error of the Joshi correction formula is 70~90%. For horizontal wells, the calculation error of the new capacity formula is within 10%, and for multi-branch wells, the calculation error is within 15%. It should be noted here that the capacity of multi-branch wells is calculated as roughly 1.5 times that of horizontal wells, according to the empirical relationship of production between these two types of wells. The capacity calculated by the conventional method seriously underestimates the actual reservoir capacity, and the capacity formula following the matrix permeability leads to a large error. The capacity formula considering the natural fracture in this paper can greatly reduce the error, and the prediction result is much closer to the actual capacity, which confirms the accuracy and effectiveness of this method.

Table 3. Basic parameters of well X.

Notation	Physical Meaning	Parameter Value (Zone A)	Parameter Value (Zone B)	Unit (of Measure)
B_o	Crude oil volume factor	1.041	1.041	dimensionless
h	Effective reservoir thickness	4.9	5.7	m
k_m	Permeability of matrix block	0.001	0.0412	darcy
s	Natural fracture density	0.0095	0.0016	1/cm
b	Average width of natural fracture	380	210	μm
D	Fractal dimension (math.)	2.1	2.1	dimensionless
θ	Abnormal diffusion coefficient (physics)	0.05	0.05	dimensionless
β_k	Stress sensitivity factor	0.0083	0.0027	1/MPa
μ_{eff}	Formation Crude Oil Viscosity	5.6	5.6	mPa·s
p_e	Initial formation pressure	17.97	17.97	MPa
p_w	Bottom hole pressure	12.95	12.95	MPa
G	Threshold pressure gradient	0.0074	0.0018	MPa/m
r_e	Supply radius	720	2240	m
L	Horizontal section length	242	1120	m
r_w	Wellbore radius	0.2159	0.2159	m

Table 4. Comparison of the results of capacity calculation by different methods.

Name of Well	Stratum (Geology)	Actual Capacity (m^3/d)	Joshi Correction Formula (m^3/d)	Chen Capacity Formula (m^3/d)	New Capacity Formula (m^3/d)	Error 1 (%)	Error 2 (%)	Error 3 (%)
3H	Zone A/B	90.20	48.24	32.26	82.56	−46.52	−64.23	−8.47
4M	Zone A/B	416.50	197.75	111.14	469.20	−52.52	−73.32	12.65
5M	Zone A/B	459.60	218.61	135.37	393.68	−52.43	−70.55	−14.34
6H	Zone A/B	142.00	72.79	46.16	148.92	−48.74	−67.49	4.87
7M	Zone A	239.00	53.37	37.43	207.52	−77.67	−84.34	−13.17
8M	Zone A	398.00	88.70	67.03	454.59	−77.71	−83.16	14.22
9H	Zone A/B	288.00	192.45	104.83	307.15	−33.18	−63.60	6.65
10M	Zone A	447.00	82.06	54.94	508.36	−81.64	−87.71	13.73
11H	Zone A/B	307.30	154.20	101.70	324.51	−49.82	−66.90	5.60

The novel capacity formula presented here marks a significant advancement over existing methods. It accurately captures the complex interplay between natural fractures and reservoir properties, leading to a more precise prediction of production capacity. This enhancement is evident in our results, where the model demonstrates an average error reduction to less than 15%, which is a substantial improvement compared to conventional methods.

- Example application and verification of vertical wells

  The conventional generalized capacity formula is depicted as Equation (23).

$$Q = 86.4 \frac{2\pi h k_m}{B_o \mu_{eff} \beta_k} \frac{p_e - p_w}{\ln r_e - \ln r_w}. \tag{23}$$

Based on Equation (15), when the natural fracture is undeveloped in the low-permeability reservoir, the capacity formula of the vertical well is expressed as Equation (24).

$$Q = \sum_{j=1}^{N} q_j = \sum_{j=1}^{N} 86.4 \frac{2\pi h_j k_{mj}}{B_o \mu_{eff} \beta_{kj}} \left[\frac{e^{-\beta_{kj}[(p_e - p_w) - G_j(r_e - r_w)]} - 1}{e^{\beta_{kj} G_j (r_e - r_w)} \ln r_w - \ln r_e} \right]. \tag{24}$$

The development case data of vertical wells in offshore low-permeability reservoir with natural fractures are few; two wells are applied to verify the correctness of the new capacity formula in this paper. The FA15-Y well were shot holes in Zone A and Zone B, respectively; the basic parameters are as shown in Table 5. This well shows strong longitudinally heterogeneity, the production of DST test is 127.3 m^3/d, and the capacity calculated using the conventional generalized capacity Equation (23) is 78.5 m^3/d, which indicates a huge error. Applying the method in the paper, based on the post-drilling physical properties of the limestone reservoir, and substituting the basic parameters of the FA15-Y well into the production capacity Equation (15) for vertical wells of a low-permeability reservoir with development of natural fractures, a production capacity is calculated based on each measurement point in the logging curve. The final steady-state production capacity of a single well of 115.47 m^3/d is obtained by integration and summation, of which the error is only about 9.30% compared with the DST test, which is much closer to the test data.

Table 5. Basic Parameters of well FA15-Y.

Notation	Physical Meaning	Parameter Value (Zone A)	Parameter Value (Zone B)	Unit (of Measure)
B_o	Crude oil volume factor	1.041	1.041	dimensionless
h	Effective reservoir thickness	16	7	m
k_m	Permeability of matrix block	0.0231	0.0279	darcy
s	Natural fracture density	0.0172	0.0016	1/cm
b	Average width of natural fractures	385	210	μm
D	Fractal dimension (math.)	2.2	2.2	dimensionless
θ	Abnormal diffusion coefficient (physics)	0.05	0.1	dimensionless
β_k	Stress sensitivity factor	0.0032	0.003	1/MPa
μ_{eff}	Formation Crude Oil Viscosity	5.6	5.6	mPa·s
p_e	Initial formation pressure	17.97	17.97	MPa
p_w	Bottom hole pressure	12.636	12.636	MPa
G	Threshold pressure gradient	0.0032	0.0027	MPa/m
r_e	Supply radius	1000	1000	m
r_w	Wellbore radius	0.155	0.155	m

Substituting the actual drilling data of the FA14-Z well into the capacity Equation (24) for vertical wells of a low-permeability reservoir with undeveloped natural fractures, the calculated result of the initial capacity is 32.2 m^3/d, of which the error is 9.98% compared with the actual capacity of 29.3 m^3/d. The calculated results of the capacity prediction of vertical wells by the method promoted in this paper are relatively consistent with the actual production, and the errors are all less than 10%, which confirms the correctness and effectiveness of this method.

Based on the validation examples of vertical wells, it is concluded that the derived vertical well capacity formula agrees well with the actual initial production of the wells with an error of about 10%, which means it can be applied to the initial production prediction of vertical wells in low-permeability reservoirs with developed natural fractures.

These findings validate the efficacy of our approach and provide a more optimized capacity assessment method for this type of reservoir. Furthermore, it opens avenues for its application in other reservoir types.

4. Discussion

The analysis of the factors influencing the production of vertical and horizontal wells in low-permeability limestone reservoirs based on actual data is crucial for development strategies and field management, as it can reveal the reasons for changes in production under different conditions and provide a scientific basis for future reservoir management.

Figure 7 shows the relationship between natural fracture density and capacity at different reservoir thicknesses. This mainly represents the effect of the degree of natural fracture development on capacity. At the same thickness, the higher the density of natural fractures, the higher the production capacity. It indicates that the development of natural fractures has a positive effect on the well capacity, and only when the distribution of natural fractures is well understood can the production of wells in low-permeability reservoirs be reasonably assessed, and wells can be considered to be designed exploiting the region developing natural fractures. Natural fracture density reflects the degree of fracture development; when the fracture density is greater, vertical and horizontal wells are more likely to intersect with these fractures. In low-permeability reservoirs, the development of natural fractures can significantly improve the permeability of the rock, thus increasing the fluid mobility.

Understanding and evaluating the development of natural fractures in the development of low-permeability reservoirs is critical to predicting and increasing well capacity. Choosing areas of higher fracture density to locate wells can improve economic benefits.

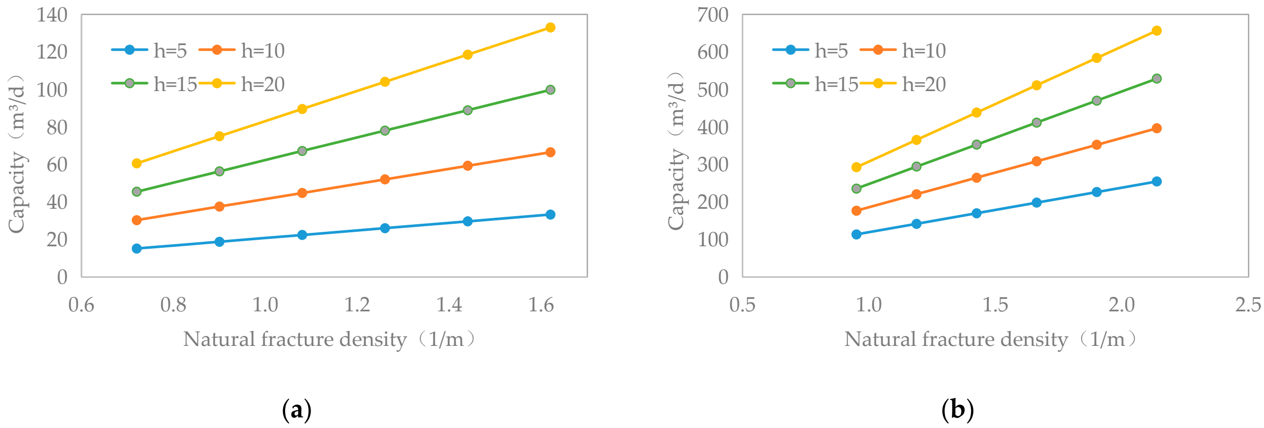

Figure 7. Relationship between natural fracture density and capacity at different thicknesses: (**a**) Vertical wells; (**b**) Horizontal wells.

Figure 8 shows the relationship between the fractal dimension and the capacity at different reservoir thicknesses, which mainly represents the effect of fractal dimension on capacity. It can be seen that the higher the fractal dimension, the higher the capacity for the same thickness. This suggests that fractal dimension, as a measure of fracture complexity, has a positive effect on well capacity. In the early evaluation of reservoirs, the study of reservoir soil stress and fracture network complexity should be emphasized. The fractal dimension D reflects the complexity and spatial distribution characteristics of the fracture network. When the fractal dimension is high, it indicates that the fracture network is more developed and the connection between fractures is more complicated, which increases the probability of intersection between effective fractures. In low-permeability reservoirs, a complex fracture network helps to increase the permeability of the rock, thereby promoting the flow of crude oil.

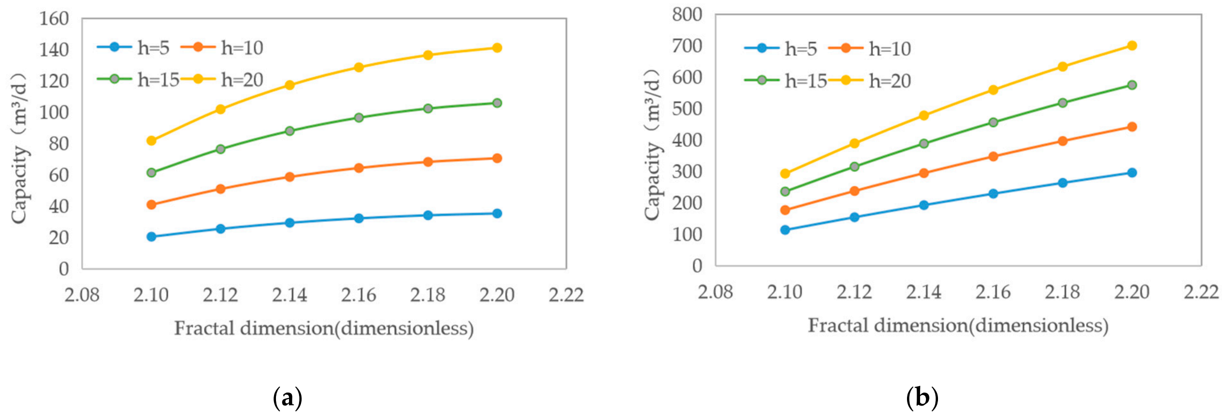

Figure 8. Relationship between fractal dimension D and capacity for different thicknesses: (**a**) Vertical wells; (**b**) Horizontal wells.

Figure 9 shows the relationship between connectivity coefficient and capacity at different reservoir thicknesses, which mainly represents the effect of natural fracture connectivity on capacity. The smaller the connectivity coefficient θ, the higher is the capacity at the same reservoir thickness. As mentioned earlier, the smaller the θ, the better the network connectivity, which may lead to a higher fluid storage capacity in the local area and means that the distribution of these fractures in the reservoir may be more favorable for the accumulation and seepage of fluid. A higher connectivity coefficient indicates that the connectivity between the matrix and fractures is poor, and the fractures formed in this case tend to be isolated, which does not improve fluid mobility in the reservoir.

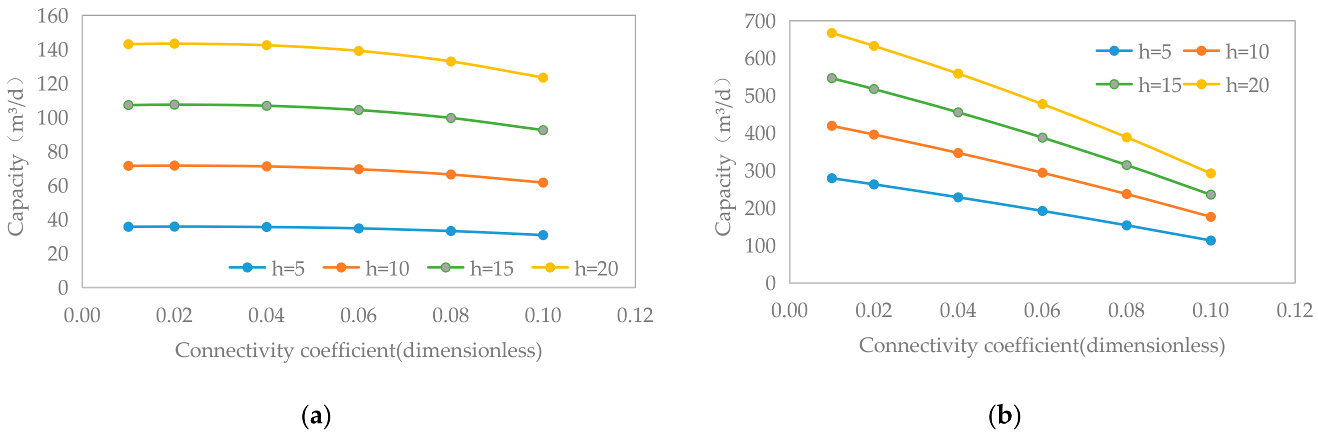

Figure 9. Curve of connectivity coefficient θ versus capacity at different thicknesses: (**a**) Vertical wells; (**b**) Horizontal wells.

Figure 10 depicts the relationship between stress sensitivity and horizontal well capacity at different reservoir thicknesses, which mainly demonstrates the effect of the stress sensitivity of the seepage characteristic parameters on capacity. As the stress sensitivity coefficient increases, the capacity of horizontal wells at different reservoir thicknesses tends to decrease. It indicates that reservoirs with a lower stress sensitivity coefficient are more favorable for oil production of horizontal wells because the permeability of the reservoir changes less under pressure changes, thus maintaining higher fluid mobility.

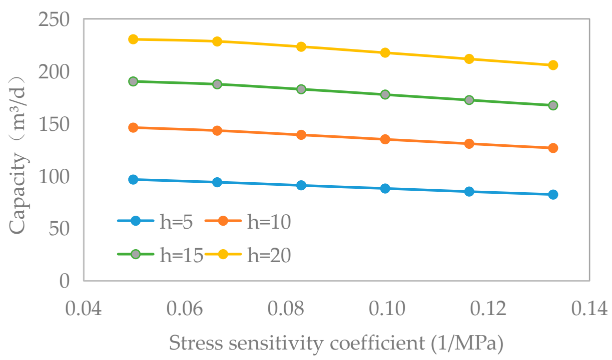

Figure 10. Relationship between stress sensitivity and horizontal well capacity at different thicknesses.

Figure 11 shows the relationship between the producing pressure difference and productivity index under different threshold pressure gradients. This figure primarily reflects the effect of the initiating pressure gradient in the seepage parameters on capacity. From the figure, as the drawdown increases, the productivity index shows an increasing trend under all conditions of threshold pressure gradient. For the same producing pressure difference, the smaller the threshold pressure gradient, the higher the productivity index, indicating that a higher oil recovery efficiency can be realized with a relatively small drawdown at a lower threshold pressure gradient. Horizontal wells with a drawdown of less than 5 MPa have a greater increase in the productivity index, and a drawdown of more than 5 MPa has a relatively small increase in the productivity index. Therefore, it is not recommended that horizontal wells in low-permeability reservoirs containing natural fractures produce at an excessive producing pressure difference. The threshold pressure gradient is the minimum pressure difference required for the reservoir fluid to start flowing.

A lower initial pressure gradient means that the oil and gas in the reservoir can start to flow at a lower producing pressure difference, which is very favorable for improving oil recovery efficiency and reducing production costs. Therefore, when formulating oil field development plans, the threshold pressure gradient of the reservoir should be considered, and the appropriate producing pressure difference should be selected to optimize oil and gas recovery and increase economic benefits.

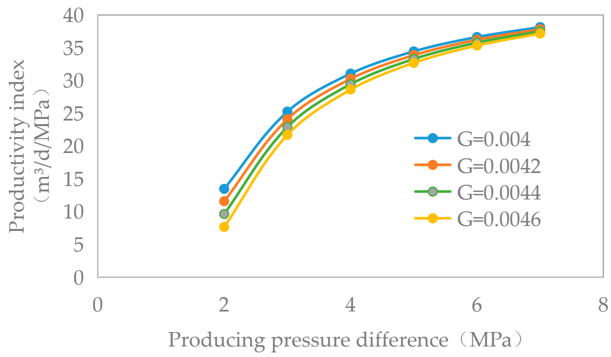

Figure 11. Relationship between producing pressure difference and productivity index of horizontal wells at different threshold pressure gradients.

The analysis and discussion above contribute significantly to understanding the complex dynamics within low-permeability reservoirs, especially those with natural fractures. The results demonstrate the importance of accurately characterizing the effects of natural fractures, stress sensitivity, and threshold pressure gradients on reservoir performance. The enhanced understanding allows for more precise capacity predictions, which is crucial for optimal reservoir management.

Applying this knowledge in real-world scenarios could lead to more effective development strategies for low-permeability reservoirs. It enables better planning and optimization of drilling and production operations, potentially improving recovery rates. The findings can guide industry professionals in making more informed decisions, especially in challenging offshore environments.

5. Conclusions

Taking into account the non-Darcy flow characteristics of fluids, stress sensitivity characteristics of porous media, random distribution characteristics of natural fractures, and strong longitudinal heterogeneity of reservoirs, this study proposes new capacity evaluation methods for both vertical and horizontal wells in low-permeability oil reservoirs containing natural fractures. It is verified that the established capacity evaluation models can be applied to accurately predict initial productivity capacity of oil wells by fitting actual production data. Based on the study of capacity evaluation models and the sensitivity analysis, several conclusions are summarized as follows.

- Aiming at the problems of traditional methods in predicting the production of offshore low-permeability reservoirs with natural fractures and the inappropriateness of traditional methods in capacity evaluation, the fractal theory is introduced to reasonably characterize the permeability of low-permeability reservoirs with natural fractures, and the steady-state capacity prediction model of vertical and horizontal wells are established, which comprehensively considers the effects of fractal fractures, threshold pressure gradient, and stress sensitivity of low-permeability limestone reservoirs. To further reveal the strong longitudinal heterogeneity during the drilling of vertical wells, it is suggested that considering the longitudinal gradient through logging curves in the evaluation of vertical well capacity can more accurately evaluate the capacity of this type of reservoir and characterize the strong longitudinal heterogeneity of this type of reservoir.

- Application examples demonstrate that our method significantly outperforms conventional models, with an average error reduction to less than 15%.
- A high-density fracture network increases the permeability and fluid mobility of the rock, which significantly improves well capacity. In addition, the increase in fractal dimension reflects the increased complexity of the fracture network, which further increases the probability of intersection between horizontal wells and effective fractures, thus facilitating the oil recovery. A lower connectivity coefficient θ is associated with higher production capacity, indicating that optimizing the connectivity of the fracture network is critical for the aggregation and seepage of crude oil. A lower threshold pressure gradient is favorable to achieve higher oil recovery efficiency under smaller producing pressure difference. The relationship between the production pressure difference and productivity index is not a simple linear relationship; it is not recommended that horizontal wells in low-permeability reservoirs containing natural fractures produce under an excessive producing pressure difference.

Therefore, a comprehensive consideration of the non-Darcy flow, stress sensitivity of porous media, random distribution of natural fractures, and strong longitudinal heterogeneity is essential for the capacity evaluation of low-permeability reservoirs containing natural fractures, which can establish a theoretical foundation for the efficient development of low-permeability reservoirs and assist in upgrading and transforming low-permeability reserves. Additionally, the derived production capacity formulas can be applied to different types of oil reservoirs including low-permeability reservoirs with or without natural fractures while changing some prerequisites. Except for vertical and horizontal wells, the capacity evaluation model of multi-lateral wells of low-permeability reservoirs containing natural fractures will be further studied in our future work.

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Conflicts of Interest: Authors Kun Wang, Mingying Xie, Weixin Liu, Li Li, Siyu Liu, Ruijie Huang, Shasha Feng and Guotao Liu were employed by the company Nanhai East Petroleum Research Institute, Shenzhen Branch of CNOOC Limited. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest. The authors declare that this study received funding from Nanhai East Petroleum Research Institute, Shenzhen Branch of CNOOC Limited. The funder was not involved in the study design, collection, analysis, interpretation of data, the writing of this article or the decision to submit it for publication.

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