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Study on Proppant Selection for Hydraulic Fracturing Design in Lower Oligocene Reservoir

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Abstract: In the past decades, a large amount of oil production in the Cuu Long Basin was mainly exploited from the basement reservoir, oil production from the Miocene sandstone reservoir and a small amount oil production of the sandstone Oligocene reservoir. Many discovery wells and production wells in lower Tra Tan and Tra Cu of Oligocene sandstone were high potential oil and gas production reserves where the average reservoir porosity was the range of 10% to 18%, and reservoir permeability was the range of 0.1 md to 5 md. Due to reservoir high heterogeneity, complicated and complexity of the geological in high closure pressure up to 7,700 psi, [12]. . The problem in the Oligocene reservoir is very low fracture conductivity due to low conductivities among the fractures of the reservoirs. The big challenges deal with this problem by using hydraulic fracturing stimulation to improve oil and gas production that is required of the study. In this article, the authors have been presented about proppant selection based on proppant technology for improved oil production. The intermediate strength proppant (ISP) of CARBOLITE- Ceramic with high proppant pack permeability, high conductivity, and proppant strength up to 10,000psi has been selected for hydraulic fracture design in the Oligocene Reservoir. To compare the quality type of proppant as 20/40 Carbolite, 20/40 Jordan sand, 20/40 HSP, the conductivity should be evaluated under closure pressure up to 7,700psi in the Oligocene reservoir. Moreover, the 2D PKN–C fracture geometry account for leak-off coefficient, spurt loss in term of power law parameters on the fracture geometry [5] and accurate fracture geometry in low permeability Oligocene reservoir, offshore Viet Nam.

Key words: Proppant selection, Hydraulic fracturing design, Lower Oligocene reservoir

I. INTRODUCTION

Hydraulic fracturing stimulation is widely used in the petroleum industry for enhanced oil production that applies the vertical well, multistage hydraulic fracturing in horizontal well. In Viet Nam, oil production rate in the Oligocene reservoir was declined in a long time due to many reasons such as pressure of reservoir is declined of oil production, the low reservoir permeability ranges from 0.1 md to 5 md, and low reservoir porosity ranges from 10 % to 18 %, heterogeneity, complicated and complexity of the reservoir. These problems lead to low conductivity among the fractures of the reservoir. To deal with this problem is to stimulate the reservoir of hydraulic fracturing stimulation. In Cuu Long Basin, there are three pay zones oil production that consist of the basement reservoir, Miocene sandstone reservoir, and the Oligocene sandstone reservoir. In the previous report has been estimated the amount of oil production reserves can be exploited from the basin about 5600 million to 5950 million barrel of oil equivalent. That is equal to hydrocarbon reserves potentially about 22.4 billion to 23.8 billion of oil equivalents. At which, the fracture basement reservoir is exploited the amount of 70 % oil production, whereas exploited of 18 % oil production in the Oligocene reservoir (1033 million barrel of oil reserves) and 12 % of oil production in the Miocene reservoir, respectively. One the other hand, total amount of oil production in Oligocene reservoir in the White Tiger oil field is only exploited of 76.7 million barrels of oil which is equal to 4.6 % total amount of oil production in the White Tiger and is equal to 7.4 % of oil in the Oligocene reservoir. These layers in the Oligocene reservoir include Tra Tan of Oligocene C, Oligocene D and Oligocene E, Tra Cu in the Oligocene F. In this article, the authors have been mentioned to the Oligocene E reservoir and have been implemented to select good proppant with high fracture conductivity as well as high proppant pack permeability, high fracture width under specific closure pressure up to 7,700 psi. In a part of proppant selection, the authors also will be correlated between the proppant conductivity versus the fracture conductivity, and fracture width. The study shows that high reservoir depth, fracture complicated, reservoir heterogeneity, are given high closure pressure is resulted the low fracture conductivity.

II. FRACTURING FLUID SELECTION AND FLUID MODEL

Ideally, the fracturing fluid is compatible with the formation rock properties; also it is compatible with fluid flow in the reservoir and reservoir pressure and is compatible with reservoir temperature. Fracturing fluid that is generated pressure in order to transport proppant slurry and open fracture, produce fracture growth during pumping, also fracturing fluid should be minimized pressure drop alongside in the pipe system in order to increase in pump horse power with the aim is increased a net fracture pressure to produce more fracture propagation. In fracturing fluid system, the breaker additive would be added to the fluid system to clean up the fractures after treatment. Due to Oligocene E reservoir is high temperature thus the Dowell YF 660 high temperature (HT) without breaker with 2% KCl [6] is selected for fracturing fluid system. To predict precisely the fracture geometry as fracture half-length, fracture width during pumping in term of the power law fluid model would be applied in this study. Then the most fracturing fluid model [3] is usually given by:

$$\tau = K\gamma^n \qquad (1)$$

Where τ –shear stress, γ – shear rate, K – consistency coefficient, n – rheological index as flow behavior index of non-dimensional but related to the viscosity of the non-Newtonian fracturing fluid model (Refer to Valko's & Economides, 1995), [5]

The power law model can be expressed by:

$$\text{Log } \tau = \log K + n \log \gamma$$

$$\text{Slope} = \left[(N\textstyle\sum XY) - (\sum X \sum Y)\right] / \left[(N \sum X^2) - (\sum X)^2\right]$$

$$\text{Intercept} = (\textstyle\sum Y - n\sum X)/N$$

Where X=log γ, Y=logτ, and N = Data number. Thus n = Slope and K= Exp (Intercept).

III. EFFECT OF CLOSURE PRESSURE ON CONDUCTIVITY AND PROPPED WIDTH

In order to estimate the magnitude of specific fracture conductivity, proppant pack permeability, proppant porosity under closure pressure up to 7,700 psi [3], many factors affect by the fracture conductivity as fracture closure pressure, reservoir pressure, reservoir temperature, type of proppant, reservoir permeability, reservoir porosity, the phase in the reservoir, the geological structure of the pay zone, and fracturing fluid damaged due to reservoir temperature. Currently, the closure pressure is the minimum pressure required to open the fractures and it is affected to porosity, permeability, and conductivity. In the Oligocene reservoir, the minimum pressure required to open fracture up to 7,700 psi [3]. It is equal to minimum horizontal stress (σ_1) of the normal faulting stress regime where the vertical stress is maximum one of the principle stress. These figures below have been shown these quality proppant in comparisons with conductivity, proppant pack permeability. In order to correlate the relationship between closure pressure versus conductivity of 20/40 Jordan sand at various proppant concentration among the fractures of the reservoir. With high confident coefficient factor is reached to 100%, the model is highly significant.

The models below present the relationship between closure pressures versus conductivity by using poly level 6 at various proppant concentration of 20/40 Jordan sand as seen in the equation (1) to equation (3). In which, x is the closure pressure in psi, conductivity is the proppant conductivity in md.ft.

$$\text{Conductivity, (md. ft)} = 10^{-17}x^5 - 7\times10^{-13}x^4 + 10^{-8}x^3 - 9\times10^{-5}x^2 + 0.0272x + 1358.8, \text{ in term of } 0.5\ \frac{\text{lb}}{\text{ft}^2} \text{ and } R^2 = 0.9973 \qquad (2)$$

$$\text{Conductivity, (md. ft)} = 2\times10^{-17}x^5 - 10^{-12}x^4 + 2\times10^{-8}x^3 - 0.0002x^2 + 0.033x + 2664.9, \text{ in term of } 1\ \frac{\text{lb}}{\text{ft}^2} \text{ and } R^2 = 0.9973 \qquad (3)$$

$$\text{Conductivity, (md. ft)} = 4\times10^{-17}x^5 - 2\times10^{-12}x^4 + 4\times10^{-8}x^3 - 0.0003x^2 - 0.0502x + 5118.1, \text{ in term of } 2\ \frac{\text{lb}}{\text{ft}^2} \text{ and } R^2 = 0.9973 \qquad (4)$$

The figure 1 illustrated that the increase in closure pressure is given reduced conductivity. The figure also demonstrated that the increase in fracture proppant concentration as 0.5lb/ft^2, 1lb/ft^2, 2lb/ft^2 on conductivity. Due to the magnitude of conductivity depends on of closure pressure, proppant fracture concentration, proppant type. In the figure 3 depicted the effect of the proppant type with same fracture proppant concentration of 0.5lb/ft^2 on propped conductivity. With the increase in the closure pressure is given lower propped conductivity. The figure 4 is presented the effect of proppant type on propped width based on the same fracture proppant concentration of 0.5lb/ft^2.

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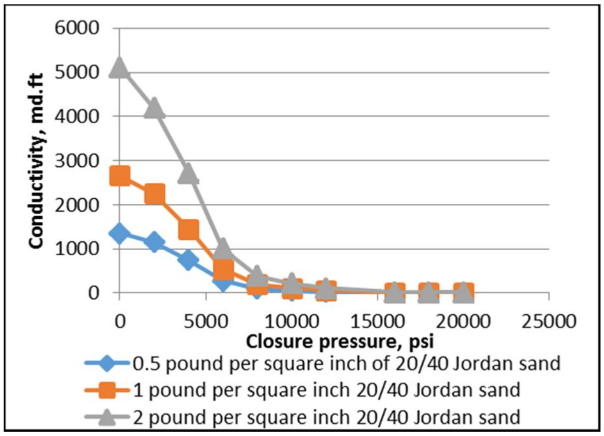

Figure 1. The effect of closure pressure and fracture proppant concentration on conductivity of 20/40 Jordan sand

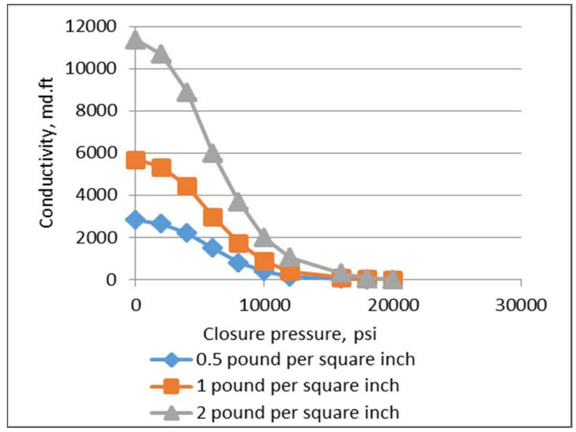

Figure 2. The effect of closure pressure and fracture proppant concentration on conductivity of 20/40 CARBOLITE-Ceramic

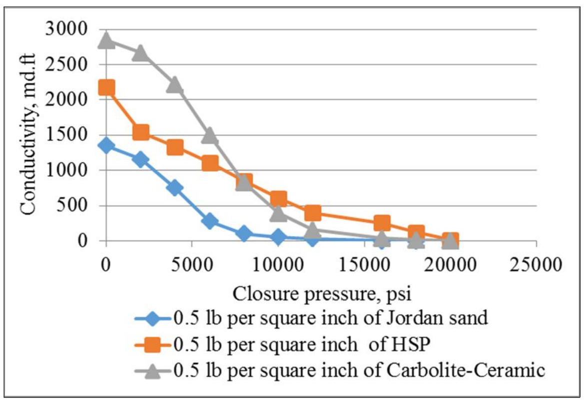

Figure 3. The effect of closure pressure and type of proppant on conductivity

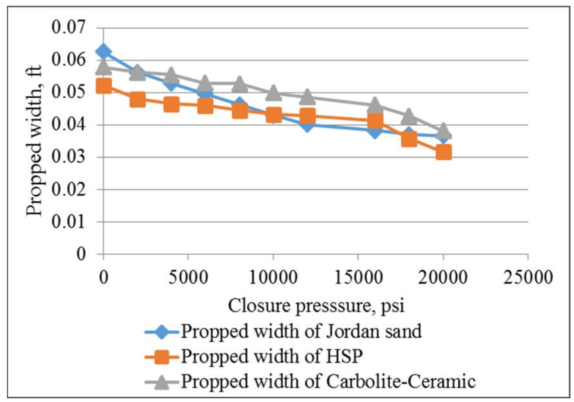

Figure 4. The effect of closure pressure and type of proppant on propped width at proppant concentration of $0.5lb/ft^2$

A. Proppant selection

To understand the size proppant, the mesh size of proppant is followed the ASTM (American standard sieve mesh). To accurate selection proppant, the two criteria proppant selection has been chosen as proppant technology and considering the cost of proppant that affects to fracture treatment. Therefore, proppant selection should be based on maximum fracture conductivity and considering the cost of proppant. Moreover, the proppant conductivity depends on several variables among the fractures as proppant type, proppant size, proppant shape, proppant porosity, proppant permeability and proppant conductivity, strength proppant under effective stress pressure of the fracture in order how to evaluate precisely the fracture conductivity of the fractures with proppant damage factor. Due to proppant is used to open fractures and maintain the fractures open for a long time in high fracture conductivity while pump pressure is shut down and fracture begins to close due to effective stress and overburden pressure. Therefore, proppant selection usually would be stronger to resistant the crushing, erosion, and resistant to corrosion in the well by intermediate strength proppant (ISP) with the proppant was made by high aluminum concentration (Al_2O_3) is greater than 50%. Due to closure pressure up to 7,700 psi [12] ,proppant selection should be considered these Carbo Lite Ceramics proppant with proppant size 20/40, high strength proppant with proppant size 20/40 Carbo-HSB that contains greater than 83 of Al_2O_3 (Gene Kim , AM2F energy 2013) refer to (Economides, 2002), [8]. Here are given some suggestion about types of proppant properties of intermediate strength proppant (ISP). In order to compare the conductivity among CARBOLITE-Ceramic proppant, High strength proppant, and Jordan sand proppant size 20/40 of containing 91% SiO_2(Gene Kim , AM2F energy 2013) , these conductivity have been evaluated under the same closure pressure and same proppant fracture concentration as $0.5lb/ft^2$, $1lb/ft^2$,and $2lb/ft^2$. The more aluminum capacity is often high cost than one. Here is suggested high strength proppant of 20/40 Carbo-HSP is given high cost than one without market.

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By selecting proppant strength follows the Economides et al, 2002.

Table 1. Types of proppant properties, [6].

Parameter	Value	Value	Value
Proppant type	20/40 CARBOLITE-Ceramic	20/40 CARBO-HSP	20/40 Jordan sand
Proppant density , ρ_p	2.71	3.27	2.648
Strength	Intermediate strength	High strength	Less
Average diameter	0.0287	0.026 inch	0.0248 inch
Proppant porosity, ϕ_p, %	35	43.7	41.7

Furthermore, proppant selection is also considered to proppant settling, proppant transport follows Stoke's Law regime. Proppant settling depends on many factors as proppant density, average proppant diameter, and the important factor is the apparent fluid viscosity. If the project is chosen the proppant large diameter and high density, leading to require high fracturing fluid viscosity as providing more polymers and fracturing fluid added to the fluid system as increasing the cost of fracture treatment.

The Stoke's Law model is given as equation below

$$V_s = \frac{2(\rho_p - \rho_f)}{36\mu} \times gD^2 \qquad (5)$$

In which, V_s is settling velocity in meter per second, g is the gravity of 9.81 meter per square inch, the ratio of ρ_P / ρ_F is the proppant density divided by fracturing fluid density (kg/m^3/ kg/m^3), and D is the average proppant diameter in meter.

To good type of proppant selection, 20/40 Carbo-lite Ceramic should be selected due to the strength propped up to 10,000 psi, and density is to 2.71. To selection Jordan sand of strength proppant is less than 7,700 psi that is not selected. Of course 20/40 high strength proppant for the project is not economical due to proppant is the high cost, high strength; high density lead to design more polymers to generate the fluid viscosity to transport that proppant. However, considering both economic and proppant technology is to choice 20/40 CARBOLITE-Ceramic ISP for the project. The cost of proppant depends on the material made to proppant without market. Thus, the cost of 20/40 high strength bauxite proppant is the high cost than one due to it is made of high Al_2O_3 concentration up to 83% (Gene Kim , AM2F energy 2013), high strength propped up to 15,000 psi and then spends more polymer to proppant transport this proppant, leading to effect the treatment cost. Finally, the good proppant selection of type and proppant properties is given in the table 2.

B. Fracture geometry model

In this study, the 2D PKN fracture geometry model (Two dimension PKN; Perkins and Kern, 1961; Nordgren, 1972) [5] in figure 5 is used to present precisely fracture geometry for hydraulic fracturing stimulation in low permeability, low porosity and poor conductivity such as an Oligocene E reservoir, that is required high conductivity as high fracture half-length of fracture design and evaluate the fracture geometry. After incorporation of cater solution II, the model is known as 2D PKN-C (Howard and Fast, 1957)[11] had incorporated of the leak-off coefficient, in term of consistency index (K), flow behavior index (n), injection rate, injection time, fluid viscosity, fracture height. The detail model refers to (Valko's and Economides in 1995) shows in the figure 5.

Table 2. Optimal proppant type of 20/40 CARBOLITE-Ceramic, [1]

Parameter	Value
Proppant type	20/40 CARBO-Lite
Proppant density, SG	2.71
Strength	Intermediate
Diameter	0.0287 in
Packed porosity	0.35
Conductivity damage factor under closure pressure up to 7,700 psi	0.5

C. PKN with fluid leak-off

Cater solution for material balance in term of fluid leak-off into fracture area and describe the magnitude of fracture geometry as fracture width, and fracture half-length during injection for fracture propagation alongside fractures, that is resulting from PKN-C fracture model refers to Valko and Economides (1995). The aim of the solution is to predict the magnitude of the fracture area increasingly in the reservoir account for the fluid leaking into the formation and fracture propagation, which derived from Carter Equation (Howard and Fast, 1957)[12] . The material balance in term of injection rate to the well at injection time t, and τ is the

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time for open fracture. The open time fracture depends on rock properties such as young's modulus, Poisson's ratio, fracture toughness. The material balance is implemented the relationship between injection rate (q) with fracture volume and fluid volume lost to the total fracture area. Thus, the material balance can be presented as equation below.

$$q = 2\int_0^t \frac{C_L}{\sqrt{t-\tau}} \times \left(\frac{dA}{d\tau}\right) d\tau + 2S_p \times \frac{dA}{dt} + w \times \frac{dA}{dt} + A\frac{dw}{dt} \quad (6)$$

An analytical solution for constant injection rate (q), Cater solved the material balance that is given the fracture area for two wings as:

$$A(t) = \frac{w_a + 2S_p}{4C_L^2\pi} \times q\left[\exp(\beta^2)\,\mathrm{erfc}(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1\right] \quad (7)$$

Hence fracture half-length with the fracture surface area ($A(t) = 2x_f h_f$) is given by

Where is $\beta = \frac{2C_L\sqrt{\pi t}}{w_a + 2S_p}$

D. PKN-C fracture model

Valko and Economides (1995)[5] had been improved the fracture geometry from the limited result of Nordgren (1972).

The maximum fracture width in term of the power law fluid parameters that is given by:

$$w_o = 9.15^{\frac{1}{2n+2}} \times 3.98^{\frac{n}{2n+2}} \left(\frac{1+(\pi-1)n}{n}\right)^{\frac{n}{2n+2}} K^{\frac{1}{2n+2}} \times \left(\frac{(q_i/2)^n h_f^{1-n} x_f}{E\prime}\right)^{\frac{1}{2n+2}} \quad (8)$$

Where: E' is the plain strain in psi, ($E' = \frac{1}{1-\nu^2}$)

Where n is the flow behavior index (dimensionless) and K is the consistency index (Pa.sec^n), ν is the Poisson's ratio and μ is in Pa.s. (M.M Rahman, 2002), the power law parameters are modeled with fluid viscosity of fracturing fluid as:

$$n = 0.1756 \times (\mu)^{-0.1233}$$

$$K = 47.880 \times (0.5\mu - 0.0159)$$

By using the shape factor of π/5 for a 2D PKN fracture geometry model, the average fracture width (w_a) is given by $\pi/5 \times w_f$ as equation.

By using the Carter Equation II [5] in term of average fracture width, the expression fracture width from the fracture area is to generate the fracture half-length:

$$x_f = \frac{(w_a + 2S_p)}{4\pi C_L^2 h_f} \times \frac{q}{2}\left[\exp(\beta^2)\,\mathrm{erfc}(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1\right] \quad (9)$$

Where, $\beta = \frac{2C_L\sqrt{\pi t}}{w_a + 2S_p}$

Equation (9) is often to calculate the fracture half-length during proppant slurry injection into the fractures and that equation also is described the fracture propagation alongside the fractures with them, in which fracture half-length depends on several parameters as an injection rate (q), injection time (t), leak-off coefficient (C_L), spurt loss (S_p), and fracture height (h_f), the average fracture width (w_a). The valuable fracture half-length is calculated by an iterative method based on spurt loss, fracture width, injection time, injection rate, fracture height, leak-off coefficient,

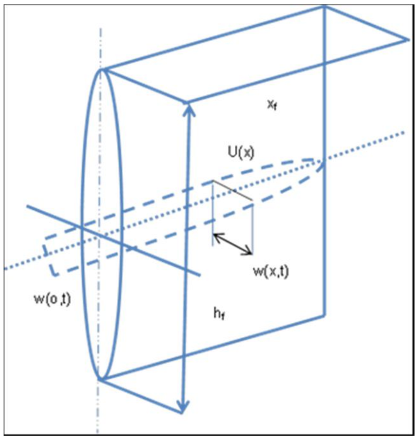

Figure 5. The PKN fracture geometry model

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IV. MATERIAL BALANCE

Cater solution for the material balance account for the leak-off coefficient, spurt loss, injection rate, injection time, and power law parameters n, K. During proppant slurry is pumped to the well to produce fracture growth and fracture propagation. In the reality, the material balance is presented as equation; $V_i = V_f + V_l$, [3] where V_i is the total fluid volume injected to the well, V_f is the fracture volume that is required to stimulate reservoir, and V_l is the total fluid volume losses to the fracture area in the reservoir . The fracture volume, V_f, is defined as two sides of the symmetric fracture by $V_f = 2x_f h_f w_a$, the fluid efficiency is defined by V_f/V_i. In 1986, Nolte proposed the relationship between the fluid volumes injected with pad volume and also proposed a model for proppant schedule. At the injection time t, the injection rate is entered into two wings of the fractures with q, the material balance is presented as the constant injection rate q is the sum of the different leak-off flow rate plus with fracture volume as:

The fluid efficiency at the end of job calculates by the equation below:

$$\eta = 1 - \left(\frac{V_f}{V_i}\right) \qquad (10)$$

Equation 10 shows that high fracture volume at the post fracture is provided high fluid efficiency.

V. FRACTURE CONDUCTIVITY

The magnitude of fracture conductivity usually is measured from laboratory data (API standard) that is based on proppant type, proppant size, proppant shape, proppant damage factor, proppant permeability, closure pressure, proppant porosity are under closure pressure. The API standard for a test such as data to measure linear flow through the proppant pack between steel plates under specific pressure is applied to it. Then the standard API is usually tested at a proppant concentration of 2lb/ft^2. This theory most published data measured by API test (Smith, 1997)[11].

If the proppant permeability under closure pressure is known for the proppant type was selected, then in-situ fracture conductivity can be evaluated by

$$\text{Fracture conductivity} = k_f \times w_p \qquad (11)$$

For simulation fracture conductivity if the closure pressure, proppant fracture concentration in (lb/ft^2) is known by using Mfrac software also can be calculated a fracture conductivity, proppant permeability, proppant porosity under closure pressure as seen in these figure 1, Figure2, figure 3, and figure 4.

VI. DIMENSIONLESS FRACTURE CONDUCTIVITY

The dimensionless fracture conductivity, F_{CD}, can be defined as (Cinco-Ley et al., 1978) [7], [3] is given by:

$$F_{CD} = \frac{k_f \times w_p}{k \times x_f} \qquad (12)$$

In which:

k is the reservoir permeability in mD and x_f is the fracture length of fractured well in ft.

k_f is the proppant permeability under closure pressure apply on the proppant laden, and w_p is the propped fracture width at end of the job.

VII. TRANSIENT PRODUCTION FLOW REGIME

Based on the constant bottom hole pressure situation the oil production from fractured well in transient flow regime can be calculated by (Economides et al., 1994), [3].

$$p_i - p_{wf} = \frac{162.6 q_0 B\mu}{kh}\left(\log t + \log\left(\frac{k}{\phi\mu c_t r_w'^2}\right) + s_f - 3.23\right) \qquad (13)$$

In which, r_w' is the effective wellbore radius as given by: $r_w' = r_w e_f^{-s}$, s_f is pseudo-skin is calculated by the relationship (Valko's et al., 1997): $s_f = F - \ln\left(\frac{x_f}{r_w}\right)$, where x_f is the fracture half-length, and r_w is the wellbore radius. The F factor can be calculated by:

$$F = \frac{1.65 - 0.328u + 0.116u^2}{1 + 0.18u + 0.064u^2 + 0.005u^3} \qquad (14)$$

Where $u = \ln(F_{CD})$ and F_{CD} is the dimensionless fracture conductivity which is calculated by $F_{CD} = \frac{k_f w_p}{k x_f}$, also F_{CD} is related to proppant number which is along the penetration ratio ($I_x = 2x_f/x_e$) and $k_f w_p$ is the fracture conductivity which can be calculated by laboratory experiment or conductivity simulation when knows a proppant fracture concentration in lb/ft^2 among fractures under closure pressure apply on the proppant laden. Basically, the proppant number is defined by (Economides et al., 2001), [8].

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$$N_{propp} = \left(\frac{2k_f}{k_{res}}\right) \times \frac{V_{prop}}{V_{res}} \quad (15)$$

Where k_f is the effective proppant pack permeability; k is the reservoir permeability; V_{prop} is the propped volume in the pay zone (two wings, including void space between the proppant grains); and V_{res} is the drainage volume. In the transient production period is often short time oil production.

VIII. RESERVOIR DATA IN THE LOWER OLIGOCENE RESERVOIR AND HYDRAULIC FRACTURING PARAMETERS

Reservoir data are taken from the IPTC-16966 [12]. that mentions in the lower Oligocene sandstone reservoir as a tight oil reservoir. The details of the reservoir parameters show in the table 3. The important parameters are reservoir depth up to 12,286 ft and fracture closure pressure up to 7,700 psi. The sandstone reservoir properties have shown the young's modulus up to 5,000,000 psi. This reservoir selected for hydraulic fracturing stimulation due to production rate is very low compared to the potential reserves. Moreover, the reservoir is covered and bounded by shale with high young modulus. In the hydraulic fracturing parameter is considered by the field experience and fracturing fluid properties.

Table 3. Hydraulic fracturing parameters

Parameter	Value
Fracture height, h_f, ft.	72
Sandstone Poisson's ratio	0.25
Leak-off coefficient, ft/min$^{0.5}$	0.003
Young's modulus, psi	5.00×10^6
Injection rate, bpm	20
Injection time, min	90
Spurt loss, gal/ft^2	0.1
Proppant concentration end of job, ppg	8
Flow behavior index, n	0.57
Consistency index, K, lbf.s^n/ft^2	0.024
Fracturing fluid type: Dowell YF 660 HT without breaker with 2% KCl	

Table 4. Oligocene reservoir data of X well in offshore Viet Nam, [1]

Parameter	Value
Target fracturing depth, ft.	12,286
Reservoir drainage area, acres	122
Reservoir drainage radius, ft.	1,300
Wellbore radius, ft.	0.328
Reservoir height, ft.	72
Reservoir porosity	0.121
Reservoir permeability, md	0.5
Reservoir fluid viscosity, cp	1.5
Oil formation volume factor, RB/STB	1.4
Total compressibility, psi^{-1}	1.00×10^{-5}
Young modulus, psi	5×10^6
Sandstone Poisson Ratio	0.25
Initial reservoir pressure, psi	4,990
Reservoir temperature, ^{0}F	266
Oil API	36.7
Gas specific gravity	0.79
Bubble point pressure, psi	1,310
Flowing bottom hole pressure, psi	3,500
Closure pressure, psi	7,700

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IX. RESULTS AND DISCUSSIONS

The results show the fracture geometry of fracture half-length of 587 ft, and the average fracture width of 0.303 inches based on the material balance is to generate the fracture geometry. Furthermore, a large fracture volume is the longer fracture half-length and wider fracture width due to fracture half-length is directly proportional to fracture width. Inversely, the thin fracture volume is given shorter fracture half-length as well as narrow fracture width. The post fractured well is used to predict the production rate. However, the production rate of the post fractured well depends on many parameters as fracture conductivity among the fractures of the reservoir, the magnitude of 405.11 is the actual value fracture conductivity among the fractures in the Oligocene reservoir that the fracture closure pressure up to 7700 psi and proppant fracture concentration up to 1.89 lb/ft^2, proppant pack permeability, propped width and the result of production rate is referred to parameters in table 6. For a long time oil production rate is declining due to decrease in the fracture conductivity under decreasing parameters as closure pressure, proppant crushing, proppant embedment, proppant fracture concentration. The post fractured well shows the fold of increase in oil production of 4.5 and the effective wellbore radius of 119.7 ft at pseudo skin of -5.9 that is clearly shown high fracture conductivity. The figure 6 is clearly shown the cumulative production of stimulated well is large cumulative production compared to unstimulated well. The transient time is directly proportional to square fracture half-length and inversely proportional to reservoir permeability. The model explains that if the fracture half-length is halved, leading to dimensionless time is given by one quarter. The dimensionless time is given by the equation below:

$$t_{Dxf} = \frac{2.634 \times 10^{-4} kt}{\phi \mu C_t x_f^2}$$

Where the k is the reservoir permeability in md, t is the transient time in hours,μ is the reservoir fluid viscosity in cp, Ct is the total compressibility in psi^{-1}, x_f is the fracture half-length in ft. In the figure 4 clearly demonstrated that the fractured well of cumulative production is much more than unstimulated well. This explanation the fold of productivity is 4.5.

Table 5. Results from material balance

Parameters	Value
Proppant mass	160097
Fracture half-length, ft	587
Average fracture width, inch	0.303
Near wellbore fracture width, inch	0.484
Injection time, minutes	90
Net pressure, psi	117
Fracture area, ft^2	84528
Total volume required, Vi , gal	75600
Efficiency, η	26.5
Pad volume, gal	43926
Time to pump pad vol., min	52
Average slurry conc, ppg	4.68
Prop. conc. in fracture, lb/ft^2	1.89

Table 6. Production model

Parameters	Value
Closure stress, psi	7,700
Fracture conductivity, mD-ft.	405.11
Dimensionless fracture cond., FCD	1.71
Pseudo-skin	-5.9
Fold increase in productivity	4.5
Effective wellbore radius, ft	119.7

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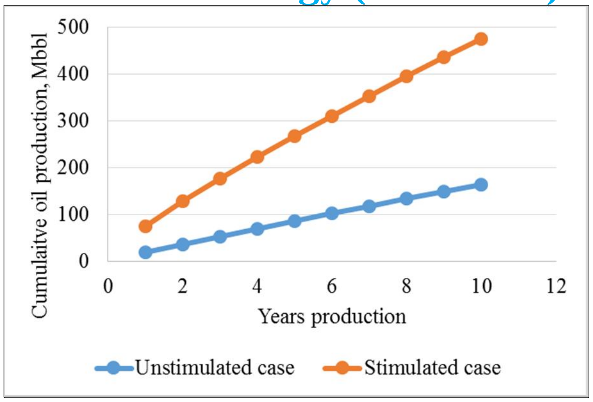

Figure 6. The cumulative oil production of unstimulated case and Stimulated case versus year's production

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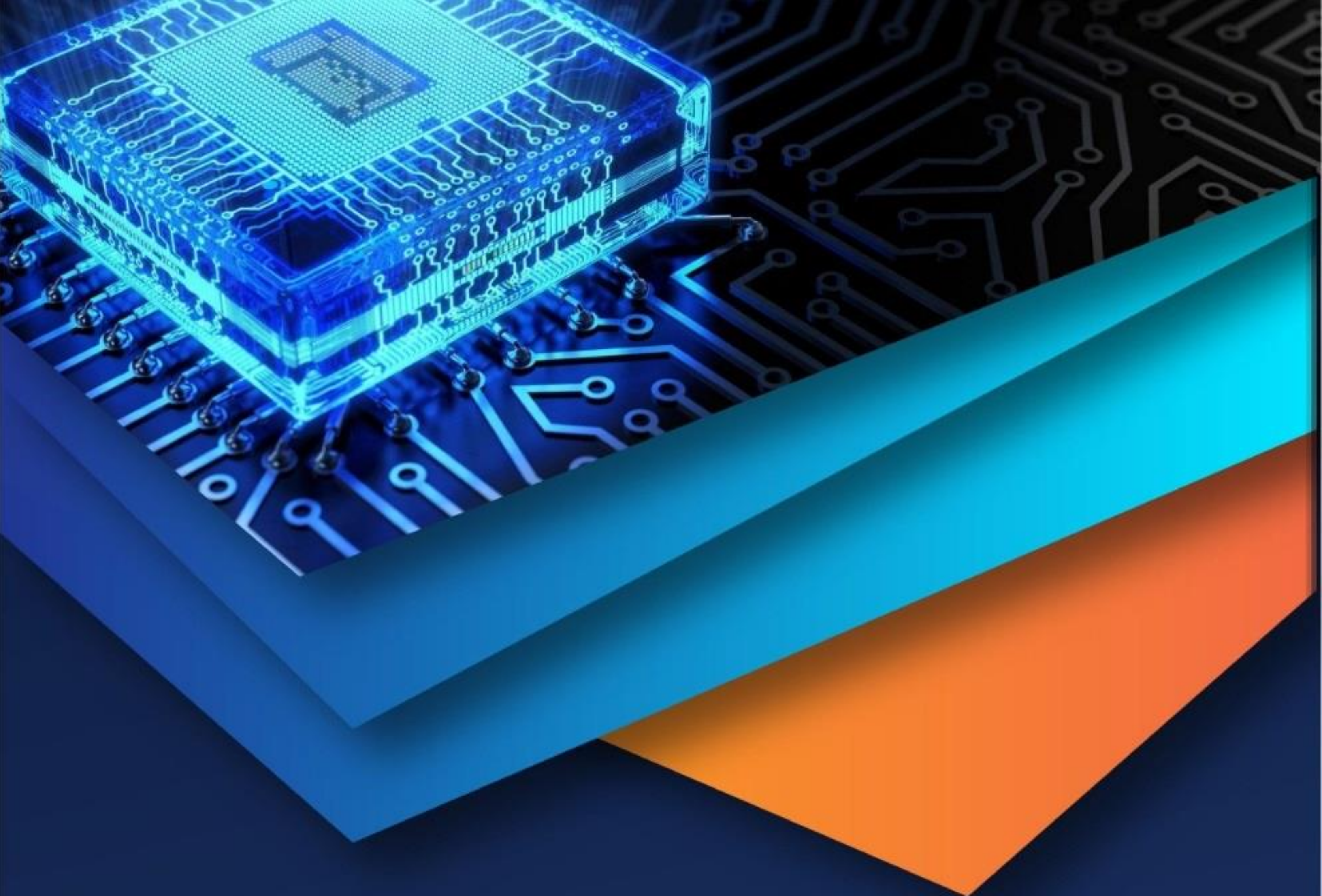

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