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OPTIMIZATION OF OPERATING FRACTURING PARAMETERS FOR IMPROVING OIL PRODUCTION IN LOWER OLIGOCENE E RESERVOIR USING RESPONSE SURFACE METHOD, OFFSHORE VIETNAM: A CASE STUDY

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Abstract. In the recent days, hydraulic fracturing technique has been widely used to improve oil production with different reservoir characteristics such as low or high formation permeability, low or high formation porosity, formation damage. However, previous research did not mention the optimization for fracturing parameters including the injection rate, injection time, and leak-off coefficient to stimulate the Oligocene E reservoir, which is based on optimum oil production performance at which maximum net present value has been achieved. The problems in the Oligocene reservoir are too low production rate due to high reservoir depth, high closure pressure up to 7,700 psi, low reservoir permeability, low porosity and geological structure with heterogeneous reservoir, high temperature, resulting in low conductivity. To deal with these problems, fracturing technique is the best choice to stimulate this reservoir. The study focuses on optimizing fracturing parameters by applying the CCD and RSM by which economic production performance has been maximized at 119 $ in 10 years. The optimum fracturing parameters have been found as injection rate of 47 bpm, injection time of 119 minutes and leak-off coefficient of 0.003 ft/min$^{0.5}$ in 50 pounds per thousand gallons of polymer (HPG). The optimal fracture geometry has been obtained with the fracture half-length of 1,449.44 ft and fracture width of 0.567 in. The rest of experimental laboratory is to measure fracture conductivity at 3,400 mD.ft in terms of proppant fracture concentration of 1.78 lb/ft^2 and high closure pressure of 7700 psi. The post fractured well shows an increase in oil productivity of 7.5 folds.

Keywords: Operating hydraulic fracturing parameters, central composite design, response surface methodology.

INTRODUCTION

In the past decades, a large amount of oil production in White Tiger oil field was from basement reservoir. However, in recent years, cumulative oil production in the basement reservoir has been declining due to high water cut in the amount of water daily injected to the reservoir and the amount of aquifer in the reservoir to maintain reservoir pressure in the secondary oil production. At the present, the best way to increase cumulative oil production in the E deposit sequence Oligocene sandstone reservoir in the Cuu Long Basin, which is located in the Southeast of the continental shelf offshore Vietnam, is widespread distribution in different areas such as the Northeast, Southeast, East and Northwest edges with distinct petro types including claystone, siltstone, sandstone, conglomerate, volcanic sediment (tuff) and extrusive rock. In order to prove the effective hydraulic fracturing, the fracture treatment for a pay zone of a well in the Southeast of the Cuu Long Basin has been undertook, the post fractured well has shown higher oil production rate compared to oil production rate of the base case. Regarding the petrophysical composition of that well, sandstone is mostly interbedded with andesite and dolerite. The E sequence Oligocene sandstone in this region is arkose sand with medium and coarse size aggregate, low to medium selection, granite rock (23.4%), calcite (5–10 % and sometimes up to 40%), zeolite (5–10%, at some areas up to 42%), kaolinite clay (10–15%). The major porosity of the E deposit sequence conducts for several structures in the Northwest with the average quantity of in-situ pore varies from 10% to 15%, sometimes over 20% due to the increase in the secondary porosity from 1% to 2% of the dissolution of unstable minerals. The aim of hydraulic fracturing stimulation is to stimulate the reservoir for improving oil production rate, in which post fractured well has also shown an increase in oil production rate. The Oligocene reservoir has shown potentially high oil production reserves with reservoir pressure up to 4,990 psi and reservoir temperature of 266^{o}F in the reservoir depth varying from 3,211 m to 4,356 m [1]. In the principal stresses, the in situ-stress distributed in the reservoir is normal faulting stress regime at which the vertical stress maximizes value one [2]. During injecting fracturing fluid into the fractures, the fracture length propagation is directly to the plan containing vertical stress and maximum horizontal stress that is perpendicular to the minimum horizontal stress. On the field, the valuable closure pressure is determined by the method of step rate test, at 7,700 psi. This value will be affected by whether bottom hole injection pressure or pump horsepower requirement. The main issues in the Oligocene reservoir are heterogeneous reservoir and complicated geology structure and both reservoir porosity and reservoir permeability are low, with the porosity varying from 12% to 18% and the permeability variation from 0.1 mD to 5 mD, respectively. To deal with these issues, the reservoir needs to be stimulated in order to enhance the oil flow rate which is the purpose of the study. By achieving the calibration test, fracture geometry model in the tight oil Oligocene sandstone reservoir has been determined, with PKN-C [3]. The simple systematic hydraulic fracturing procedure has been briefly introduced, including fracture geometry model, material balance and net present value model. In the previous study of hydraulic fracturing, the research did not mention the optimization of fracturing parameters such as injection rate, injection time and total leak-off coefficient for fracture treatment in the tight oil sandstone Oligocene reservoir. Therefore the study on optimization of fracturing parameters is necessary. Finally, the CCD and RSM [4] allow optimizing operating hydraulic fracturing parameters based on maximum NPV.

FRACTURE GEOMETRY MODEL

In the reality, there are various fracture models used for fracture treatment design, which are 2D fracture geometry without fluid leak-off such as GDK, PKN and Radial [5, 6] and the 2D fracture geometry with fluid leak-off and power law parameter index consisting of PKN-C, GDK-C and Radial-C [3, 7]. Also, the 2D models give the constant fracture height during pumping, therefore, the 2D models without fluid leak-off did not estimate accurately fracture geometry. However, the PKN-C fracture geometry model accounting for the leak-off coefficient and power law parameter index have been proven to calculate these fracture length and fracture width more exactly than the other fracture models such as PKN, GDK and the Radial model. It is also clear that the 2D PKN-C model is sufficient to design fracture treatment in the multi-layer problems as well Rahim and Holditch (1995) [8].

2D PKN - C

The opening time is defined as the time for opening fracture and denoted by τ. The injection time for a fracture treatment is the time t. The leak-off volume rate is given via the fracture surface element as [3]:

$$\frac{\partial V_L}{\partial t} = \frac{C_L}{\sqrt{t - \tau}} \times \partial A \tag{1}$$

When knowing the fracture surface area growth during injection, the function of fracture area of $A(\tau)$ can be inverted to $\tau(A)$. Then the leak-off volume rate into two wings of the fracture surface area is given by the following model:

$$2\int_0^{A(t)} \frac{C_L}{\sqrt{t - \tau(A)}} dA = 2\int_0^t \frac{C_L}{\sqrt{t - \tau}} \frac{dA}{d\tau} \qquad (2)$$

During proppant slurry is pumped into the well under high pressure in order to produce fracture surface area, the volume of spurt loss due to fracture area is yielded by.

$$2S_p \times \frac{dA}{dt} \qquad (3)$$

To estimate the fracture efficiency, the crucial parts of the fracture growth and fracture propagation are presented by the fracture volume, which is given by the model below:

$$w\frac{dA}{dt} + A\frac{dw}{dt} \qquad (4)$$

Cater solved the material balance in terms of constant injection rate into the well and the injection time t since the injection volume rate is injected into one wing of the fractures (q, bpm). The model therefore presents the material balance, which defines the injection volume rate (q) equal to total volume leak-off flow plus fracture volume created:

$$q = 2\int_0^t \frac{C_L}{\sqrt{t - \tau}} \frac{dA}{d\tau} d\tau + 2S_p \frac{dA}{dt} + w\frac{dA}{dt} + A\frac{dw}{dt} \qquad (5)$$

Cater also solved the material balance that is given by the fracture area for two wings of the fractures as [3]:

$$A(t) = \frac{w + 2S_p}{4C_L^2 \pi} \times q\left[erp(\beta^2)erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1\right] \qquad (6)$$

From the fracture area produced, then the fracture half-length has been yielded ($A(t) = 2x_f h_f$) by [3]:

$$x_f = \frac{w + 2S_p}{4C_L^2 \pi h_f} \times \frac{q}{2}\left[erp(\beta^2)erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1\right] \qquad (7)$$

Where: $\beta = \dfrac{2C_L\sqrt{\pi t}}{w + 2S_p}$

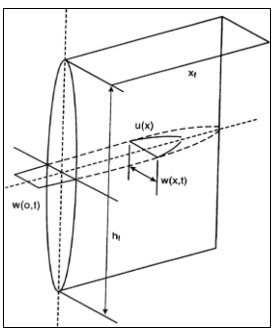

Fig.1. The PKN fracture geometry [10]

MATERIAL BALANCE

Cater solved the material balance that accounts for the leak-off coefficient, spurt loss, injection rate, injection time, and power law behavior n and consistency index, K. During proppant slurry is pumped into the well to produce fracture growth and fracture propagation, the material balance is presented by the equation; $V_i = V_f + V_l$, where V_i is the total fluid volume injected into the well, V_f is the fracture volume designed that is required to stimulate reservoir and V_l is the total fluid volume lost in 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 the ratio of the fracture volume divided by the total volume injected (V_f/V_i). In 1986 [2, 3, 9], Nolte had proposed the relationship between the fluid volumes injected with pad volume and also given a model for proppant pumping schedule.

FRACTURE CONDUCTIVITY

The value of fracture conductivity is usually measured from laboratory data (API standard) based on proppant type, proppant size, proppant shape, proppant damage factor, proppant permeability, proppant porosity under specific closure pressure. The API standard for a real test to measure linear flow through the proppant pack between steel plates under specific pressure is applied to it. The conductivity API is usually tested at a proppant concentration of 2lb/ft^2 that the theory had published by API test [10].

When the proppant permeability under closure pressure is known for the proppant type that is selected, then the in-situ fracture conductivity can be measured by:

$$Fracture\ conductivity(md.ft) = k_f \times w_p \quad (8)$$

PROPPANT MASS REQUIREMENT

Proppant slurry concentration is defined by the total volume injected minus pad volume for a fracture treatment. Then the proppant slurry injected into the fracture was given by the model below [2, 3, 7]:

$$V_{Slurry} = V_i - V_{pad} = V_i - \frac{1-\eta}{1+\eta}V_i = \frac{2\eta}{1+\eta}V_i \quad (9)$$

The proppant mass requirement for the fracture treatment is given by the model below:

$$M_p = \overline{C_p} V_{Slurry} = \eta C_f V_i \quad (10)$$

In which: $\overline{C_p}$ (ppg) is the average proppant slurry concentration during pumping which is given by:

$$\overline{C_p} = \frac{C_f}{1 + \frac{1-\eta}{1+\eta}} \quad (11)$$

C_f is the proppant slurry concentration at end of the job, ppg; η is the fluid efficiency, %, which is defined by the following model [1]:

$$\eta = \frac{V_f}{V_i} = \frac{7.48 \times 2x_f h_f \overline{w}}{V_i} \quad (12)$$

PROPPED FRACTURE WIDTH

For a given proppant mass M_p, which has been injected into the wells to produce both fracture half-length and fracture height, the proppant slurry is assumed to be distributed uniformly among the fracture areas, which is created. Therefore proppant mass among the fractures has been given by the model below [2, 3]:

$$M_p = 2x_f h_f w_p (1 - f_p)\rho_p \quad (13)$$

The proppant concentration among the fractures is defined by the following model:

$$C_p = \frac{M_p}{2x_f h_f} \quad (14)$$

Likewise, the propped fracture width created among the fracture which is defined by the following model:

$$w_p = \frac{C_p}{(1-\Phi_p)\rho_p} \quad (15)$$

DIMENSIONLESS FRACTURE CONDUCTIVITY

The dimensionless fracture conductivity, F_{CD}, defined by Argawal et al., (1979), Cinco-Ley and Samaniego (1981), which is given by the model below [2, 11, 12]:

$$F_{CD} = \frac{k_f w_p}{k x_f} \quad (16)$$

PSEUDO-SKIN FACTOR

S_f is pseudo-skin which is calculated by the relationship from Valko's et al., (1997):

$$S_f = F - \ln(\frac{x_f}{r_w})$$

The F factor is calculated by the model below [2, 12]:

$$F = \frac{1.65 - 0.328u + 0.116u^2}{1 + 0.18u + 0.064u^2 + 0.05u^3} \quad (17)$$

NET PRESENT VALUE (NPV) MODEL

The net present value is defined as the revenue in the forecasted oil production from a fractured well minus the forecasted oil production in the same reservoir with unstimulated well and the total cost of treatment in current dollars in the period of time. In this research, the net present value of the future revenue can be calculated by following equation:

$$NPV = \sum_{j=1}^{N} \frac{(V_F)_j}{(1+i)^j} - \sum_{j=1}^{N} \frac{(V_0)_j}{(1+i)^j} - C_{tr} \quad (18)$$

$$C_{tr} = C_{pr} + C_{tfl} + C_{pu} + FC \quad (19)$$

OLIGOCENE RESERVOIR DATA

The well had been drilled with the objective appraisal well passing through both the fractured basement reservoir and the Oligocene E sandstone reservoir in the Cuu Long Basin offshore Vietnam. The reservoir data for fracture treatment is gathered from the Lower Oligocene E reservoir with the reservoir depths ranging from 3,400 m to 4,000 m that has been described in the table below.

Table 1. Proppant data

Parameters	Values
Proppant type	20/40 CARBO-Lite
Specific gravity	2.71
Strength	Intermediate
Diameter	0.0287 in
Packed porosity	0.35
Conductivity at 7,700 psi closure pressure (at 1.78 lb/ft^2)	3,400 md-ft.
Conductivity damage factor	0.6
Closure pressure	7,700 psi

Table 2. Fracturing fluid data

Parameters	Values
Fluid type	Dowell YF 660 HT without breaker with 2% KCl
Fluid specific gravity	1.05
Viscosity@ shear rate	100 s^{-1}
Temperature	300^{o}F
Hydraulic Diameter	1.995 in

Table 3. Reservoir data in the lower Oligocene E sandstone reservoir [13]

Parameters	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's modulus, psi	5×10^6
Sandstone Poisson's ratio	0.25
Initial reservoir pressure, psi	4,990
Reservoir temperature, ^{o}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
Fracturing parameters	
Fracture height, h_f, ft.	72
Sandstone Poisson's ratio	0.25
Leak-off coefficient, ft/min$^{0.5}$	Available
Young's modulus, psi	3.00×10^6
Injection rate, bpm	Available
Injection time, min	Available
Spurt loss, in	0
Proppant concentration at end of job, ppg	8
Flow behavior index, n	0.69
Consistency index, K, lbf.s^n/ft^2	0.04
Fracturing fluid type: Dowell YF 660 HT without breaker with 2% KCl	
Economic data	
Fracturing fluid cost, $/gal	1
Proppant cost, $/lb.	1
Hydraulic horse power cost, $/hhp	20
Fixed cost, $	15,000
Revenue discount rate, i, %	10
Oil price, $/bbl	100

RESULTS AND DISCUSSIONS

The study researches three operating fracturing parameters including injection rate, X_1, injection time, X_2, and the leak-off coefficient, X_3. Due to fracturing treatment in the lower Oligocene sandstone reservoir, the fracturing parameters have been considered here in which the injection rates must be low pressure loss through pipe systems that varied from 40 bpm to 50 bpm and the injection time must be constrained in order to keep high fluid efficiency that the injection time has been controlled from 60 minutes to 120 minutes and the leak-off coefficient also ranged from 0.003 ft/min$^{0.5}$ to 0.007 ft/min$^{0.5}$ [14]. These parameters are provided to use the CCD [15, 16] that is presented in table 4 and table 5. With the operating hydraulic fracturing parameter condition (k = 3), the replicated tests at the center (n_0 = 3) and the total run cases required about ($2^3 + 2\times3 + 3 = 17$), the results are presented in detail in table 7 with the cumulative oil production periods in 10 years.

Table 4. Three independent variables and their levels for (CCD)

		Low	**Center**	**High**
Variable symbol		-1	0	1
Injection rate (bpm)	X_1	40	45	50
Injection time, minutes	X_2	60	90	120
Leak-off coefficient, ft/min$^{0.5}$	X_3	0.003	0.005	0.007

Table 5. Independent variables and results of post fractured production with simulation observed by (CCD)

Coded level of variables				**Actual level of variables**			**Responses (Simulation observed)**	
Run	X_1	X_2	X_3	bpm	Minutes	ft /min$^{0.5}$	Cumulative oil production (bbl)	NPV, $mm
1	-1	-1	-1	40	60	0.003	1498200	103
2	1	-1	-1	50	60	0.003	1557400	109
3	-1	1	-1	40	120	0.003	1595500	112
4	1	1	-1	50	120	0.003	1660100	118
5	-1	-1	1	40	60	0.007	1134700	88.4
6	1	-1	1	50	60	0.007	1386100	93.1
7	-1	1	1	40	120	0.007	1410700	95.3
8	1	1	1	50	120	0.007	1467600	100
9	-1	0	0	40	90	0.005	1446900	94.1
10	1	0	0	50	90	0.005	1505300	104
11	0	-1	0	45	60	0.005	1427200	96.9
12	0	1	0	45	120	0.005	1514300	105
13	0	0	-1	45	90	0.003	1557400	115
14	0	0	1	45	90	0.007	1406700	94.9
15	0	0	0	45	90	0.005	1477300	105
16	0	0	0	45	90	0.005	1477300	105
17	0	0	0	45	90	0.005	1477300	105

RSM [17–19] is the best tool in order to find optimization of operating fracturing parameters compared with the traditional method of finding single optimal parameter. This method can save the fracture treatment cost due to suitable design leak-off coefficient and the optimal injection rate, pumping time based on the maximum net present value (NPV). The correlation between response and the independent variables has been detailed as the fracture conductivity model below.

$$\begin{aligned} Y = {} & 103.332 + 3.13X_1 + 3.99X_2 - 8.53X_3 - 3.03168X_1^2 - 1.13169X_2^2 + 2.86831X_3^2 + \\ & 4.2134\times10^{-6} X_1X_2 - 0.325X_1X_3 - 0.525X_2X_3 \end{aligned} \tag{20}$$

Table 6. Regression coefficient of the predicted quadratic polynomial model

NPV	Standard Coefficient	Standard Error	P	Confident Interval (±)
Constant	103.332	0.923094	1.19698×10^{-12}	2.1828
X_1	3.12999	0.682187	0.0025192	1.61314
X_2	3.99	0.682187	0.000631345	1.61314
X_3	-8.53	0.682187	4.82224×10^{-6}	1.61314
$X_1.X_1$	-3.03168	1.31794	0.054966	3.11648
$X_2.X_2$	-1.13169	1.31794	0.418948	3.11648
$X_3.X_3$	2.86831	1.31794	0.0659952	3.11648
$X_1.X_2$	4.2134×10^{-6}	0.762708	1	1.80354
$X_1.X_3$	-0.325	0.762708	0.682826	1.80354
$X_2.X_3$	-0.525	0.762708	0.513396	1.80354
	N = 17	Q^2 = 0.825		Cond. no = 4.4382
	DF = 7	R^2 = 0.969		Y-miss = 0
		R^2 Adj =0.930		RSD = 2.1573
				Confident level = 0.95

Main and interaction effect plots. The main effect plots are used to analyze these independent variables and the interaction variable effects on the fracture conductivity. Fig. 4 presents the effects plots of these parameters on the NPV, which can be separated into two regions including negative region and positive region. The first region has presented these factors of the independent variables and interaction variables below zero including X_3, $X_1.X_1$, $X_2.X_2$, $X_2.X_3$, $X_1.X_3$, $X_1.X_2$ that are presented in Equation 20. The second region performs these factors of the variables above zero including X_2, X_1, $X_3.X_3$ as seen in the model 20. Due to those positive factors, when increasing the independent variables and interaction variables, the net present value has an increase in comparison with the increase in the negative factors. The maximum net present value is presented in the top area in fig. 3, then the maximum NPV has been found at 119 million USD according to optimization of the leak-off coefficient at 0.003 ft/min$^{0.5}$, the injection rate at 47 bpm, and injection time at 119 minutes.

Optimization of operating fracturing parameters for hydraulic fracturing in Oligocene reservoir

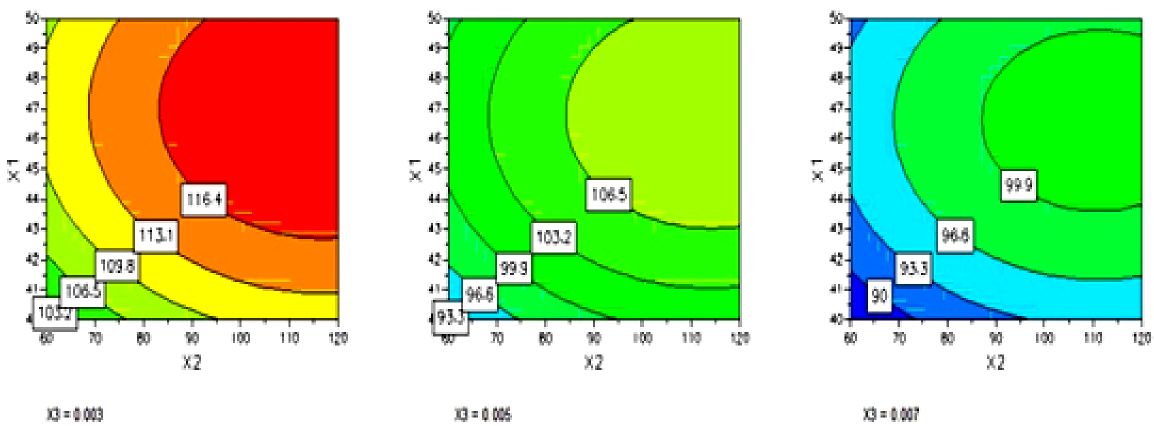

Fig. 2. Response surface plots (2-D) showing the effect of the variables on the net present value

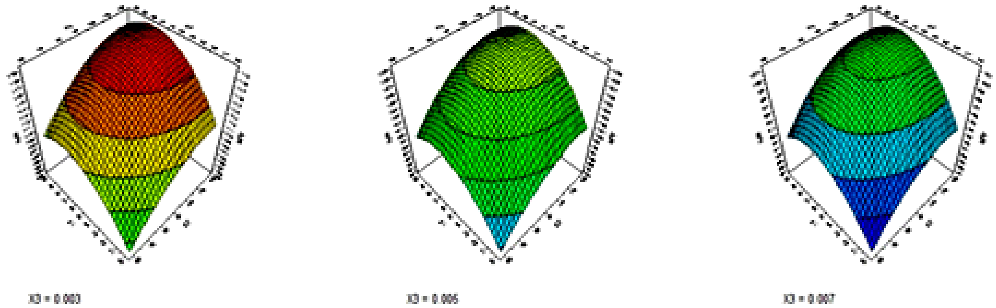

Fig. 3. Response surface plots (3-D) showing the effect of variances to the net present value

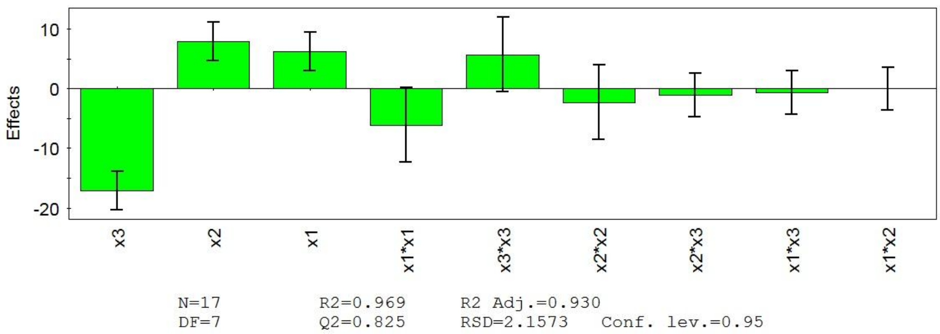

Fig. 4. The degree of factors to effects on the NPV

Results from optimal operating fracturing parameters. Table 7 shows the result of the optimum fracture geometry including fracture half-length and maximum near wellbore fracture width, at 1,449.44 ft. and 0.567 in, respectively. To achieve the maximum fracture geometry, the operating fracturing parameters have been determined as seen in fig. 4–5.

Table 7. Results on optimal fracture geometry

Parameter	Value
Fracture half-length, ft.	1,449.44
Maximum near wellbore width, in	0.567
Average fracture width, in	0.356

Proppant concentration schedule. Fig. 5 has presented proppant loading concentration schedule and described how proppant slurry has been added to the fracturing fluid in order to increase proppant concentration until proppant concentration reached end of the job (EOJ) at 8 ppg. In addition to hydraulic fracturing, there are three stages of pumping schedule; the first stage is to pump the pad volume which is injected to well without proppant. After injecting the pad volume, the proppant is added to the fracturing fluid to make proppant slurry that continues to be pumped into the fractures under high pressure and the third stage is to inject the flush that only contains frac-fluid without proppant. In the more detail, fig. 5 briefly describes the proppant pumping schedule.

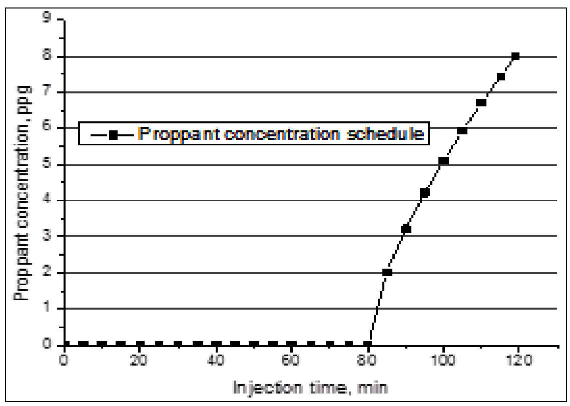

Fig. 5. Proppant concentration schedule during pumping

Table 8. Results

Parameter	Value
Result from material balance	
Fracture area, ft^2.	208,719
Fracture volume, gal	555,842
Total fluid volume injected, gal	234,906
Fluid efficiency, %	19.7
Pad volume, gal	157,524
Time to pump pad volume, min	80
Average slurry concentration, ppg	4.8
Mass of proppant requirement, lb.	370,561
Proppant fracture concentration, lb/ft^2	1.78
Optimum parameters	
Optimal leak-off coefficient, $ft/min^{0.5}$	0.003
Optimal injection rate, bpm	47
Optimal injection time, min	119
Maximum net present value, $ Million	119

Production profile analysis

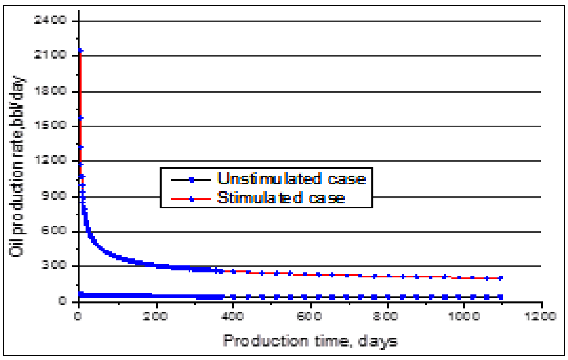

Fig. 6. Transient oil production from unstimulated case and stimulated case

Table 9. Results from fracture conductivity and production stimulation at optimal operating parameters using 20/40 CARBO-Lite Ceramic proppant

Parameter	Value
Closure pressure, psi	7,700
Fracture conductivity, md-ft.	3,400
Dimensionless fracture conductivity, F_{CD}	2.34
Pseudo-skin factor, s_f	-7.18
Effective wellbore radius, ft.	432
Productivity ratio	7.5

Fig. 6 presents the transient oil production from unstimulated case and stimulated case. The figure shows the oil production rate from fractured well higher in comparison with the oil production rate from unstimulated case. Table 9 shows that the post fractured well has experienced an increase in oil productivity of about 7.5 folds, in which oil production rate increases considerably.

CONCLUSIONS

From this work, it is possible to carry out the fracturing stimulation according to optimal operating parameter conditions which could be summarized by the following views.

The RSPM and CCD are the best tools to find the optimum fracturing parameter conditions of hydraulic fracturing in the tight oil sandstone Oligocene reservoir, where the maximum NPV is determined at 119 $ and optimal injection rate, injection time, and leak-off coefficient at 47 bpm, 119 minutes, 0.003 $ft/min^{0.5}$, respectively.

The 2D PKN-C fracture geometry model is suitable for fracturing in the tight oil sandstone Oligocene reservoir in which fracture half-length is greater than the fracture height.

By applying optimal fracturing parameters for a fracture treatment in E sequence Oligocene sandstone reservoir, the fractured well has shown an increase in oil productivity of 7.5 folds, in which oil production rate from stimulated well is much higher in comparison with the oil production rate from the unstimulated well.

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Nomenclatures

C_L = Total leak-off coefficient, $ft/min^{0.5}$; t = Injection time, minutes; q = Injection rate, bpm; S_p = Spurt loss, gal/ft^2; w = Fracture width, in; τ = Time to open fractures, minutes; A= Area fracture created, ft^2; M_p= Proppant mass, lbm; C_f = Proppant concentration at end of the job, ppg; $\overline{C}_p$ = Average proppant slurry concentration, ppg; η = The fluid efficiency, %; V_i = Total volume injected, gals; V_{pad} = Pad volume injected, gals; X_f = Fracture half-length, ft; H_f = Fracture height, ft; $\overline{w}$ = Average fracture width, ft; C_p = Proppant concentration in the fractures created, lb/ft^2; w_p = Propped width created in the fractures, ft; ϕ_p = Proppant porosity under closure pressure, %; ρ_p = Proppant density, lb/ft^3; K= The reservoir permeability, mD; x_f = The fracture length from a fractured well, ft; k_f = The proppant permeability under closure pressure, mD; w_p = The propped fracture width at end of the job, ft; $u = \ln(F_{CD})$; F_{CD} = The dimensionless fracture conductivity; r_w = The wellbore radius, ft; C_{tr} = The total treatment cost; C_{pr} = The total proppant cost; C_{tfl} = The total fluid cost; C_{pu} = The total pumping horse power cost; FC = The total fixed cost; NPV = The net present value of a fractured well; N= The number of year periods; V_F = The fracture value production revenue of a stimulated case reservoir; V_0 = The fracture value production revenue of an unstimulated case reservoir; i = The discount rate in %; CCD = Central Composite Design; RSM = Response Surface Methodology; HPG = Hydroxypropyl Guar.

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