SIMULATION OF HYDRAULIC FRACTURING AND INVESTIGATION OF PARAMETERS AFFECTING FRACTURE DESIGN IN AN OIL RESERVOIR

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Abstract

Most reservoirs in Iran are in the second half of their lifespan, and their production rate has been reduced since they exist in a pressure decline phase. Hydraulic fracturing is a technique used to increase production in these reservoirs. Hydraulic fracturing is a well-stimulation technique, which is proper for low and medium-permeability reservoirs that cannot provide cost-effective production even after the removal of the damage caused by acidization. Acid is injected into the formation under a pressure that is higher than the pressure of formation fracture. This kind of stimulation creates a new fracture and enlarges the previous cracks and fractures opening a way for oil or gas to flow from the formation to the well. In this study, sensitivity analysis has been done on parameters of fracture design, including permeability and fracture opening within various scenarios. The extant study examined the effect of these parameters' variation on the oil production rate of the reservoir and introduced the best production scenario.

Keywords: Hydraulic Fracturing, Hydraulic Fracture Design, Oil Production, Fracture Opening Rate, Fracture Permeability

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1. Introduction

The oil extraction rate is not optimal in many reservoirs due to low or declining permeability of formation caused by asphaltene sedimentation or other problems. In these cases, oil flow into the well is decreased, and this phenomenon reduces the efficiency rate and oil recovery percentage in these reservoirs [1]. Various techniques are used for good stimulation to overcome the mentioned problems, enhance the oil recovery rate, and increase the injection of fluids into the wellbore [2].

Many techniques, such as acidizing are used to stimulate well and increase permeability; however, the extant study examines the hydraulic fracturing that has a considerable effect on high-permeable reservoirs. The appropriate fluid and required additives are pumped into the well in hydraulic fracturing. After the pressure is increased exceeding the sum of in-situ (or in-place) stresses and tensile strength of the rock, the areas around the rock are broken, and some cracks appear. The high flow rate and pumping pressure, which exceed the capacity and bearing rate of the reservoir rock will break the reservoir rock creating cracks in it. The created fracture and crack increase the rock permeability. The higher the pumping rate, the wider the fractures’ length and width. Acid or water is used in the pumping process then a substance called proppant is used with water to prevent the broken and cracked stone from being closed again and allow fluids to flow while maintaining permeability. In this method, a fluid with low viscosity but high pressure is injected into the well to create a crack and expand it. The major fluid its viscosity is higher than the viscosity of a pre-injection fluid with retaining elements injected into the well in the next step, which expands the width of the crack. Moreover, the retaining elements available in the well prevent the crack from being closed. The major fluid decreases viscosity, so a channel with high hydraulic conductibility for oil flow remains.

Ding (1996) conducted a numerical method to model the fractured wells using a reservoir simulator. This study carried out the modeling on the fractures with high conductivity assuming that fractures can be a part of the well. It is important to consider the flow type (steady-state or pseudo-steady-state) around the well. Moreover, Ding introduced a formula for pressure distribution in the steady-state flow. This formula is general and applicable to all kinds of fractures. The results of the simulation were acceptable for large grades, and this technique could be used for modeling steep fractures [3].

Perkins and Gonzalez (1985) developed a numerical method to calculate horizontal stress changes resulting from temperature or pressure change in a region of elliptical cross-section and limited thickness. According to examples that used suitable thermoelastic features of stones, injection of cooled ware can considerably reduce the ground stresses around the injection well causing a break in the pressures that are lower than the expected rate in the absence of upper-elasticity [4].

Hegre (1996) simulated the hydraulically fractured horizontal wells. In general, the fracture must be modeled, and small cellular networks should be applied near the fracture to simulate the initial transient pressure of a horizontally fractured well. Hegre does not recommend cellular networks-based modeling for fracture with infinite conductivity, but simply connects the well opening to each cell of the network adjacent to the fracture and models the fracture by determining the suitable connectivity factors of the well. If the fracture is explicitly modeled, computer numerical stability is suggested to reduce time and problems, which increases the fracture's width. Moreover, decrease the permeability to maintain the fracture's conductibility. Moreover, the concept of wellbore effective equivalent radius has provided accurate results for multiphase problems and reservoir management objectives. This technique is applicable only If the horizontal fracture well is completely placed in one cell of the network [5].

Pengwei Mou et al. (2021) found the influence of hydraulic fracturing on the microfractures of coal (10-1000μm) as an important part of the simulation mechanism of Coalbed methane (CBM) hydraulic fracturing, which is important for improving CBM productivity. In this study, coal samples were selected from CHENGZHUANG and SIHE Mine for hydraulic fracturing simulation experiments, by using stereoscopic microfracture scanning and image processing method. Moreover, some parameters, such as mean aperture, surface density, mean length, fracture porosity, and permeability changes were measured under the different in-situ stress conditions before and after hydraulic fracturing. It was found that hydraulic fracturing could increase the permeability of microfractures. The permeability of microfractures after hydraulic fracturing was 0.43-14.82 times greater than the rate before fracturing. Hydraulic fracturing does not create new microfractures but expands the original microfractures, which causes an increase in mean aperture (39.85%), mean length (47.70%), and porosity of microfracture (115.59%). Under the conditions of hydraulic fracture, interlayer differences exist in the coal samples with stronger heterogeneity. Hydraulic fracture prioritizes the microfractures in the direction of parallel bedding planes. The minor the horizontal in-situ stress difference, the more expanded the microfractures uniformly during hydraulic fracturing, which is more proper for the connection of microfractures [6].

Ahamed et al. (2021) studied the impact of proppant loading, type of coal, and fracture roughness on the fluid flow characteristics of proppant-containing fracture by doing a series of triaxial permeability experiments along with micro-CT imaging. The results indicate that proppant application in coal is only effective for deep gas reservoirs with effective stress greater than 6-8 MPa. In these reservoirs, the permeability of the proppant-containing fracture can be one or two times greater than the permeability of the fracture that does not contain proppant. Proppants in the hydraulic fracture are prone to be accumulated in uneven borders of high and low surfaces that can stimulate the major leave propagation in formation by creating higher loading in these areas [7]. The effectiveness of proppants in hydraulic fracture depends on the coal mass maturity. According to results obtained by Ahmed and colleagues, coals with a smaller roughness rate will increase proppant loading, while coals with higher roughness cause crushing proppants and stressing the layers [8].

Mingyang Zhai et al. (2022) presented a three-dimensional flow-stress-damage (FSD) model to simulate hydraulic fracture propagation and stimulated reservoir volume (SRV). The results showed that injection rate, fluid viscosity, and horizontal stress difference are the key factors that control SRV. It is difficult to increase the injection rate for SRN improvement at the higher horizontal stress differently than the lower horizontal stress difference. This model could effectively optimize the hydraulic fracture geometry and SRV. The results of the model could provide an insight into the fracture geometry in deep fractured sandstone reservoirs, and be a solution for design and optimization of the well performance [9].

2. Numerical Method

The hydraulically created fractures take fluids from the reservoir's matrix and move the fluid to the well opening by developing the canals. The efficiency rate of fractured wells depends on two phases of fluid received from the formation and transferred to the well opening. The efficiency rate of the first phase depends on the length and height of the fracture, while the efficiency of the second phase depends on the permeability of the fracture. The importance of each option is expressed by the concept of fracture conductivity.

$$F_{CD} = \frac{k_f w}{k x_f} \quad (3\text{-}1)$$

F_{CD}: conductivity of fracture without dimension

w: width of fracture based on the foot

x_f: half-length of fracture based on the foot

k_f: Permeability of fracture based on the foot

When the coordinate of fracture is less than the well's collapse area, the efficiency rate of the fractured well can be estimated based on the assumption of pseudo-radius flow in the reservoir. Therefore, the equation of the internal flow rate is written as follows:

$$(3\text{-}2) \quad q = \frac{kh(P_e - P_{wf})}{141.2B\mu(ln\frac{r_e}{r_w} + S_f)}$$

Guo (1999) expressed an analytical solution to estimate the enhanced production rate of wells:

$$the\ (3-3)\ \frac{j}{j_n} = \frac{0.72(ln\frac{r_e}{r_w} - \frac{3}{4} + S_n)}{(Z_e\sqrt{C} + S)(\frac{1}{1 - e^{-\sqrt{cx_f}}} - \frac{1}{2x_f\sqrt{C}})} C = \frac{2K}{Z_e w K_f}$$

where $\frac{j}{j_n}$ indicated enhanced production, and Z_e shows the distance between the fracture and collapse area's border.

Reservoirs with low permeability tend towards the fracture with high conductivity and gain high profit from the fracture's length, while reservoirs with high permeability naturally tend towards fractures with low conductivity. Valko et al. have expressed this case in the following equation:

(3-4) $$S_f + ln(\frac{x_f}{r_w}) = \frac{1.65-0.328u+0.11u^2}{1+0.18u+0.064u^2+0.05u^3} u = ln(F_{CD})$$

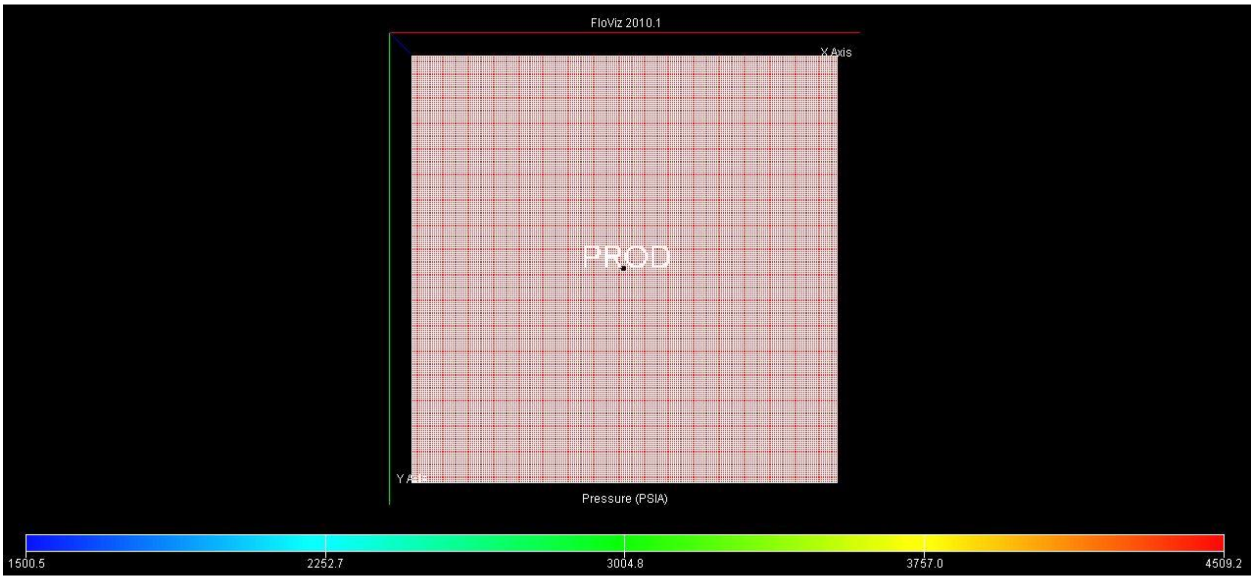
3. Modeling

3.1. Studied Reservoir

In this study, all data were gathered from a real reservoir located in the southeast of Iran, and one synthetic model was designed to examine the impact of fracture parameters on oil production through Eclipse software. This reservoir has 640000 grades. Fluid phases in this only include oil, which is created from a production well. This reservoir has 16 layers, and this model includes 200*200*16 grade. Table 1 reports the data of the studied reservoir.

Table 1. Characteristics of rock and fluid of studied reservoir

Characteristics	**Value**
Oil density	50 lb/ft^3
Matrix compressibility	5E-6 1/PSI
Porosity	0.15
In-situ oil	STB476000
Number of blocks in the simulation	640000
Matrix permeability	3md
Kv/kh	0.1md
Base depth	4000 ft
Reservoir' top	4000 ft
The initial pressure of the reservoir	4500 Psi
Radius of well	0.625ft



3.2. Characteristics of fracture

Table 2. Characteristics of fracture in different scenarios

Scenarios	**Permeability of fracture**	**Openness rate**
Scenario 1	100	0.1
Scenario 2	500	0.1
Scenario 3	1000	0.1
Scenario 4	1500	0.1
Scenario 5	100	0.05
Scenario 6	100	0.1
Scenario 7	100	0.15
Scenario 8	100	0.2

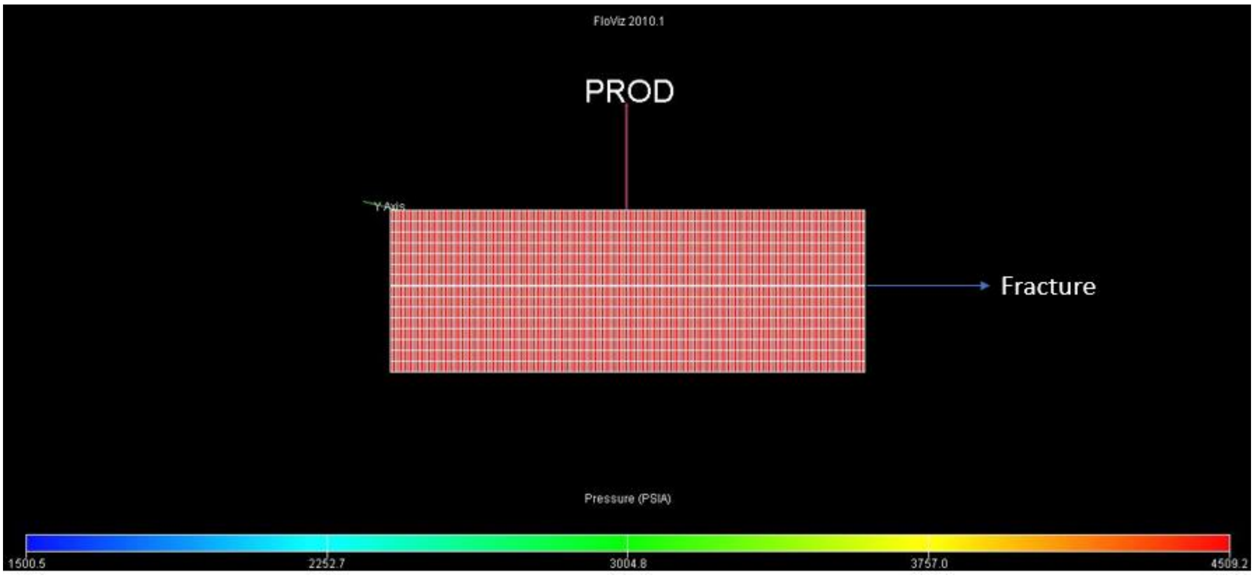
Two fractures exist in the middle of this reservoir. The fracture of each scenario horizontally exists in layer 8. In scenarios 1-4, the openness rate of fracture equals 0.1, and the permeability of fracture equals 100, 500, 1000, and 1500 in these scenarios, respectively. The permeability rate is fixed (100) in scenarios 5-8 with an openness rate of 0.05, 0.1, 0.15, and 0.2, respectively.

3.3. Characteristics of Fracture's Grade

Table 3. Characteristics of fracture's grade

	I_1	I_2	J_1	J_2	K_1	K_2
Fracture	1	200	1	200	8	8

Block's dimension equals 4ft along the x-axis, and it equals 4ft and 4ft along the y and z-axes, respectively.



4. Discussion and Simulation Results

4.1. Sensitivity Analysis

4.1.1. Impact of fracture's permeability

- **Field Oil Production Total (FOPT) and Reservoir's Pressure**

The impact of fracture's permeability equaled 100, 500, 1000, and 1500 milli Darcy (MD) (which are shown in green, blue, red, and black colors, respectively in Figure 1), considering other parameters constant. The results have been shown below.

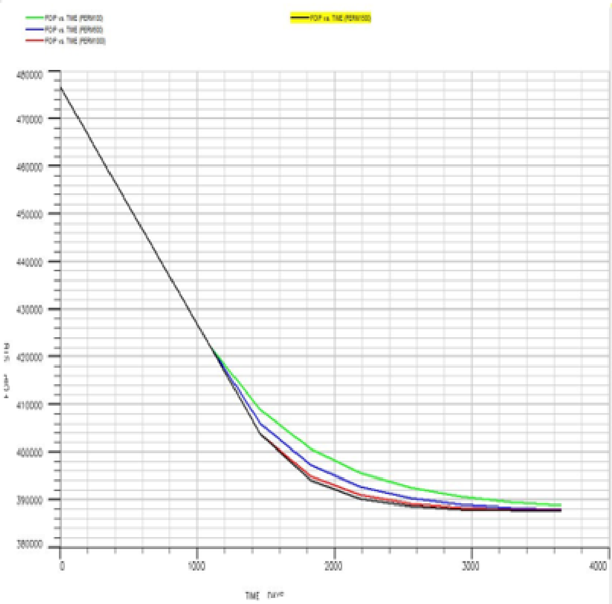


Figure 2. Comparison of FPR in different permeability rates of fracture (100,500,1000,1500 md)

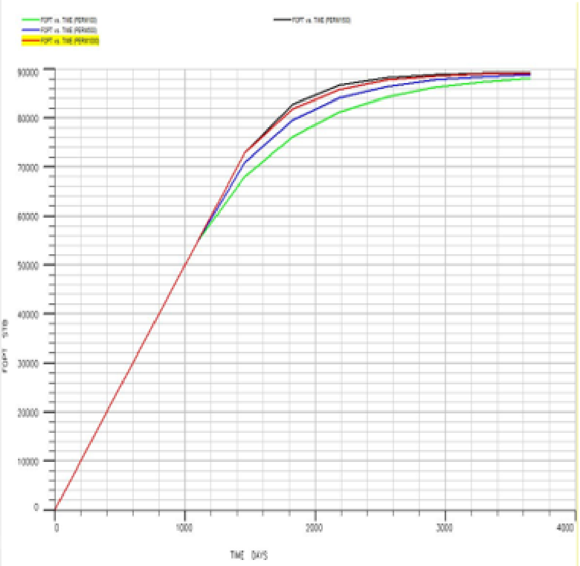


Figure 1. Comparison of FOPT in different permeability rates of fracture (100,500,1000,1500 md)

The FOPT diagram is greater for fractured reservoirs with higher permeability because the horizontal fracture with higher permeability results in more oil production so is cost-effective (the black diagram indicates the FOPT of the fractured reservoir with permeability of 1500md). According to the Figure, the fracture with a permeability of 1500md could produce 90000 oil barrels after 3650 days, while the fracture with a permeability of 100md produced 8000 barrels. Finally, these four diagrams get close to each other due to the reservoir's oil production and the decline in the oil volume of the reservoir.

The Field Pressure Rate (FPR) diagram is shown for the hydraulically fractured reservoir. Pressure changes are higher in the fractured reservoir with greater permeability (the black diagram indicates the FPR of the fracture with the permeability of 1500md) because more oil volume moves towards the well in the presence of a fracture with higher permeability, so the pressure decline rate of it is increased.

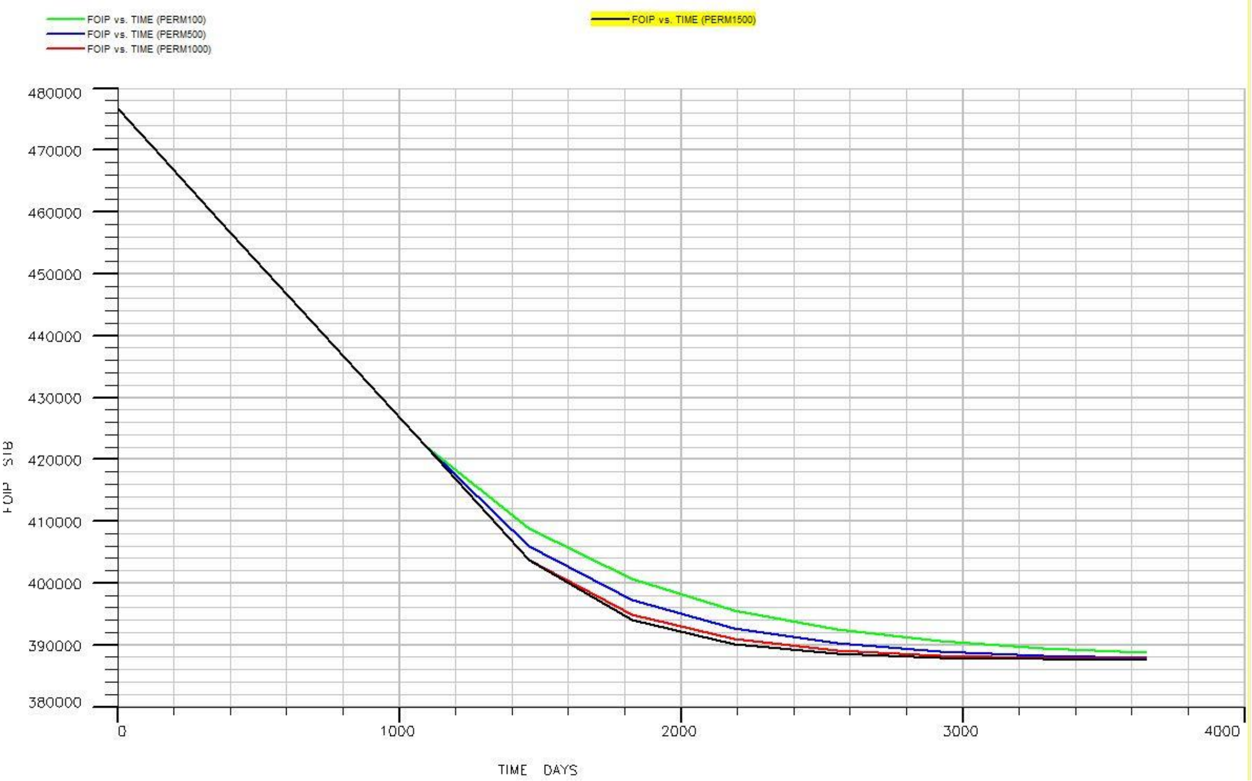


Figure 3. Comparison between in-situ oil rates in different scenarios of fracture's permeability (100,500,1000,1500md)

- **In-situ Oil**

The in-situ oil in the fractured reservoir with higher permeability is decreased rapidly because the reservoir's oil is increased while in-situ oil is reduced in the presence of the high-permeable fracture.

4.1.2. Impact of Openness of Fracture

- **FOPT and FPR**

The impact of fracture's openness equaled 0.2, 0.15, 0.1, and 0.5ft (which are shown in green, blue, red, and black colors, respectively), considering other parameters constant. The results have been shown below.

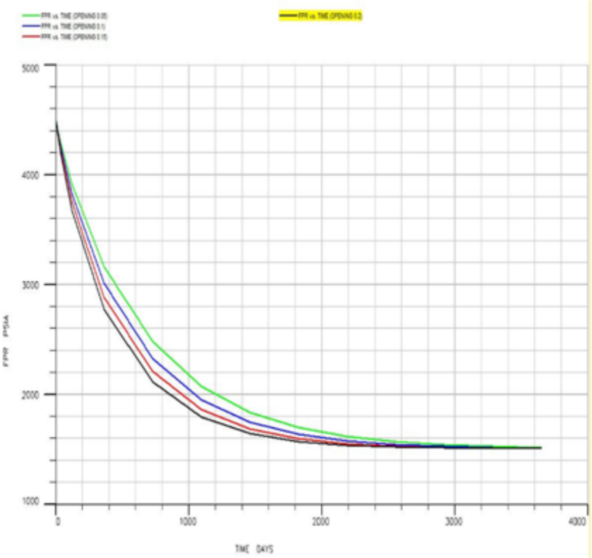


Figure 5. Impact of openness rate of fracture on the FPR (0.05, 0.1, 0.15, 0.2ft)

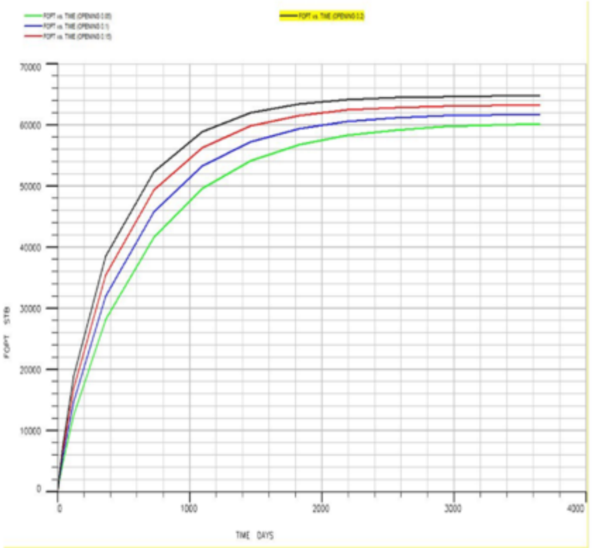


Figure 4. Comparison between FOPT and openness rate of fracture (0.05, 0.1, 0.15, 0.2ft)

According to the diagram of FOPT of the reservoir with a high-permeable, fracture is higher because the horizontal fracture with greater width results in higher fluid production. The black diagram indicates the FOPT rate of the fractured reservoir with an openness rate of 0.2ft, which its FOPT equals 65000 standard barrels after 3650 days while this rate equals 60000 standard barrels for an openness rate of 0.05ft.

According to the diagram of the FPR of the hydraulically fractured reservoir, FPR is higher in the reservoir with a wider fracture (the black diagram indicates the FPR of the fracture with an openness rate of 0.2ft) because an increased openness rate of fracture results in higher fluid production.

5. Conclusion

1. The results of simulation through Eclipse software indicate better production by creating hydraulic fractures in the studied well.
2. To design the proper hydraulic fracture of the considered reservoir, sensitivity analysis was done on the openness and permeability of fracture, and its impact on the oil production of the reservoir was shown.
3. According to the output of the reservoir simulation, increased openness and permeability of fracture rises the pressure decline and oil production of the reservoir.
4. The creation of hydraulic fracture and the increase in openness and permeability of fracture causes the discharge of in-situ oil in a shorter time. Therefore, hydraulic fracture is effective in producing oil in the short term.

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