Interpretation of Hydraulic Fracture in Low Permeability Hydrocarbon Reservoirs system

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Abstract

A new approach to make decision on fly while monitoring hydraulic fracturing pressure with the help of improvement in Nolte smith plot. Simplification and validation - Use of FRACPRO software to completely design fracturing treatment for PKN type fracture and use the same parameters to calculate design properties using MS – excel. Hydraulic Fracturing Process Steps include is to formulate the geologic model of the reservoir that should include the estimated pressure in each of the geologic layers encountered in the zones of interest. This data used to determine the needed Fracture Conductivity “FCD” and associated fracture stimulator treatment “FOI” for various proppant and fracture lengths. During this treatment modelling process fracturing fluid loss is then estimated. During the study, A fracture geometry model is designed from various rock stresses, modulus pressure, net pressure and fluid loss. This model is then calibrated, and treatment schedule is constructed using the Nolte process.

Keywords: Hydraulic Fracturing, FRACPRO, Reservoir Simulation, Fracturing Model.

Introduction

The objective of reservoir engineering is to optimize and balance the optimal benefits from a prospect area. All the individual reservoirs must be recognized and outlined by the team along with their physical properties, deducing the performance of each reservoir, preventing the drilling of unnecessary wells, initiating operational
control at an appropriate time and proper consideration of all-important economic factors. Early and precise identification and definition of the reservoir system are crucial for well-reasoned engineering. Geological studies should be complemented along with the engineering data and tests in order to provide the required information to the engineer for this purpose because the traditional geologic techniques do not provide sufficient data. Reservoir management requires an in-depth knowledge of the reservoir that can only be achieved through its characterization by the process of acquiring, processing, and integrating many basic data. [1]

In this paper, a low-permeability reservoir is one that has very low tendency of fluid to flow through porous medium. Permeability of reservoir is less than 0.1 md. In many formations due to chemical and/or physical processes changes the pore distribution including the pore size and geometry that will alter the pore openings and reduce the ability to flow of a fluid through the porous medium. To improve the Low permeable reservoir required the reservoir stimulation with the process of acid stimulation, Acid Fracturing and Hydraulic fracturing. There might be other reason for permeability reduction near by the wellbore region during the drilling and production operation where formation damage can lead to the reduction in permeability. Damage occurs as completion and drilling fluids leak off into the reservoir near wellbore area which leads to change the wellbore environment in terms of reservoir rock properties. Due to this plugging of the pores this may lead to reduction in permeability and reduction changes in flow rate. Formation Damage can be very problematic for the fractured reservoirs and for desired solution this further stimulation required as a artificially fracture while injection high pressure injection rate fracturing fluid inside the formation which leads to permeability enhancement near by the well bore area.

If this type of cases like damaged reservoir, low permeable formation and layered horizontal wells would be uneconomical unless proper action should not be taken such as hydraulic fracturing treatment. The stimulation engineer would be taken care of economic success of the project while using optimal fracture treatment design and implemented this process successfully.
Methodology

Material Balance

The growth is dominated by material balance once the fracture forms

Fracture volume = volume pumped − volume lost to fluid loss. These three volumes can be idealized as

Fracture volume   = \( H \times L \times w \) (where \( H \), \( L \) and \( w \) are the average values of height/length/width).

Volume pumped   = \( Qt_p \) (\( Q \) is the constant pump rate and \( t_p \) is total pump time).

Volume lost       = \( 4 \times CHP \times L \times t_p \) (\( C \) is the “fluid loss coefficient” discussed in the succeeding text, \( HP \) stands for the permeable or leak-off height, and \( L \) signifies tip-to-tip length). These combine to give providing the very first fracture “model”

\[
L = 2x_f = \frac{Qt_p}{4CH_pV \sqrt{t_p} + 2H_pV_{spurt} + \bar{w}H}
\]

In this case, a 1D model where \( H \) and \( w \) are specified and then length, \( L \), can be calculated. That is, when talking about the dimensions for fracture models, it refers to height, \( H \); length, \( x_f \); and width, \( w \). Alternatively, a desired \( L \) is specified and this can be solved as a quadratic for \( t_p \), that is, a design equation. This “model” then serves to illustrate which are the main variables for frac design.

Fracture Width

This still leaves width and height as major unknowns. Historically, \( w \) was the first parameter to be tackled. Assume a “slit” in the earth held closed by a far-field stress, closure stress, or closure pressure. Now, begin to increase the pressure in the slit (\( P \)) until it is greater than this closure pressure. The slit opens into an elliptical crack with width given by (Sneddon, 1946)

\[
w = \frac{2(P - \sigma_{ct})d}{E'} = \frac{2P_{net}d}{E'}
\]

\( E' = \) plane strain modulus \((\sim E, \) Young’s modulus\))

\( d = \) Characteristic dimension

\( P - \sigma_c = \) net pressure
Figure 1- Fracture Width Sneddon Equation

Here, \( w \) is the maximum width of the created fracture, \( P \) signifies the fluid pressure inside the fracture and \( \sigma_{CL} \) is the minimum in situ stress, \( d \) stands for the dimension of the original slit, and \( E' \) denotes the plane strain modulus (\( E' = E/(1 - \nu^2) \)) with \( E \) being Young’s modulus and \( \nu \) being the Poisson’s ratio for the formation (note that for \( \nu = 0.2, \ E' \) only differs by 4% from \( E \)). For a very high value of 0.35, this effect will be about 15%, which could be important in low modulus formations. Unfortunately, in terms of our 1D design equation, this does not help much—we simply traded one thing we do not know, \( H \), to another thing we do not know, \( P_{Net} \). In fact, we made things worse by introducing a brand-new variable, \( E' \). Despite these drawbacks, this variable change from \( w \) to \( P_{Net} \) is essential to the problem solution. What we need to know is fracture width; however, we can neither measure nor predict \( w \). However, \( P_{Net} \) can be both measured and predicted, and assuming one can measure or predict \( P_{Net} \) (as discussed in the following text), this has become a 2D model. That is, for a given fracture height, one calculates the width and length; but which model do we use? This started the second big debate in fracturing (the first being vertical vs. horizontal) with some companies choosing the GdK model to build 2D fracture simulators and others using the PKN approach.

2D fracture models:

We can choose from among the three common 2D models using this drop-down list.

**PKN 2D:** For 2D Fracture modelling with a constant height and width, which is proportional to the height. This PKN model is frequently used for the determination of high gel viscosity fracturing fluid injection along with water to create fracture nearby well bore region.
KGD 2D: KGD model is different than PKN model in terms of width is proportional to length with a (specified) constant height. It can infrequently be used to match measured pressures (except perhaps with forced use of back stress).

Radial: If a fracture is unable to models these above two models radial model is best to assume for radial fracturing. The model assumes axi-symmetry in radial growth.

Interpreting hydraulic fracture treating pressures helps in the recognition of periods of controllable height extension, along with the height growth as well as critical pressure. During the processing treatment of fracture extension if pressure reaches critical pressure condition, fracture extension reduced at screen out condition along with undesirable fracture height growth during stimulation process. We are going to assume in our discussion that hydraulically creation of fracture leads to be in vertical plane. In addition, for deeply penetrated fracture required limited and controllable height growth due to certain limitation. Therefore, the focal point is limited further to fractures having a horizontal penetration appreciably larger than their vertical height. The two basically diverse concepts for the spread of a constant-height vertical fracture that lead to complex result are; one concept is in which the width is constant across the height of the fracture. It is based on the assumption which states that the formation bed being fractured remains independent of the beds formed above and below it and they can slip freely at their boundaries. This ultimately leads to the hypothesis that the fluid pressure needed for the lengthening of fracture decreases with time.

For the fracture design concept specially, we were focused on the fracture height measurement concept (Perkins and Kern), which is based on the assumption that there is no, or negligible, slip of boundaries along the horizontal planes that restrain the fracture height. This postulation gave this conclusion that for the fracture extension required sufficient fluid pressure. This concept was further refined by Nordgren, which predicts that for a Newtonian Fluid creating a confined-height fracture, the well bore pressure was found to be increased proportionally to time raised to an exponent "e" at a constant injection rate:

\[ P_{net} \propto t^{e} \quad \frac{1}{8} \leq e \leq \frac{1}{5} \quad \ldots \quad \text{eq 1} \]
There would be a larger value for the assumption relative to the injection rate if the rate of fluid loss is small, whereas, if the rate of fluid loss is large then the value of the exponent would be small. For Eq. 1 and various other cases in this discussion, reference to pressure implies pressure above the fracture closure pressure. Fig. 11 shows the well bore treating pressure, above the in-situ closure pressure, vs. time for three gigantic treatments. For this configuration the treatment can be pumped down the annulus, with the surface pressure on the static line giving the bottomhole pressure after a correction for hydrostatic head. The closure pressures for the formations were determined by a pump-in/flowback of DFIT procedure. Briefly, this procedure uses the same tubing/annulus configuration and consists of injecting a volume of fluid at a sufficient rate to initiate or open a fracture in the formation. After the injection, the well is back flowed at an appropriate constant rate (e.g., through a surface choke) that varies for different formations. In the desired range of flowback rates (e.g., one-quarter of the injection rate), a plot of pressure vs. flowback time will exhibit a characteristic reversal of curvature (increasing rate of decline) when the fracture closes. The figures also demonstrate the time at which proppant was introduced into the wellbore.

**Figure 2 - Examples with the different characteristic slopes**

**Case Definition**

Following is the data obtained for Fracturing pressure Vs time by digitizing graph available in Nolte Smith paper SPE 8297. Pressure vs. time is the only output data available during real time fracturing process.
Table 1 - Pressure time and calculated e value

<table>
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<tr>
<th>S. No.</th>
<th>Time (min)</th>
<th>Pressure (psi)</th>
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Common Nolte smith plot for the following data –
Results and Discussion

From the case study we can see that fracture propagation is not a continuous process, the original Nolte-Smith analysis assumes that the fracture continuously and smoothly propagates with time. Some of the recent field observations through micro seismic monitoring especially in fractured shale formations imply that a fracture may grow in spurts. This sporadic fracture growth implies that a fracture might go through periods of ballooning followed by periods of growth. Identifying the periods of ballooning and growth will help in diagnosing problems and identifying potential sand out very early.

Comparing the original Nolte smith plot with the new “e” plot helps in determining time for which fracture is actually extending i.e. Confined height unrestricted extension.
Conclusion and Future Scope

20/40 ceramic Proppant with fracture length of 600 ft has payout period of 2.98 years which is second lowest, as the one with lowest payout period is best which eases us to recover our capital investment as early as possible. We can now look Internal Rate of Return (IRR) which is also highest i.e. 43% which puts 2 economic criteria in favour of 20/40 ceramic fracturing with fracture half length of 600 ft.

40# cross linked gel with 20/40 ceramic proppant with fracture length of 600 ft is the best as per economic analysis.

For simulation in FRACPRO by using same parameters and same proppant schedule we can see that fracture length achieved is 450 ft so we are 90% accurate in predicting fracture length.

Second important criteria is Net pressure so as per Figure 38 we can see that maximum net pressure is 800 psi while we have calculated it to be max 625 psi in which we are 78% accurate. However we have assumed the average shale-sand stress gradient difference to be 0.12 psi/ft if we had assumed it to be slightly higher 0.15 psi/ft we would be much more accurate.

For the innovation part the new e plot is only valid with constant proppant concentration but however in field we slowly increase the concentration to desired level. So in future we can incorporate the effect of proppant concentration in e plot for accurate determination.

Here we have constructed fracture process design for PKN type fracture so for other type of model such as GDK model, Radial model, and more complex 3-D model Fracture Design process can also be prepared.

References


