

Optimization of Proppant Size and Concentration in a Marcellus Shale Fracture Treatment

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Abstract

The purpose of this study was to determine the optimum proppant size and end-of-job proppant concentration for a hydraulic fracture treatment in the Marcellus shale. Although the Marcellus shale is known to contain huge reserves of natural gas, only a tiny fraction of that gas would be recoverable without effective stimulation methods. In this study, data from an actual well completed in the Marcellus shale, along with some estimated rock properties, was entered into the MFrac hydraulic fracturing simulator in order to determine which set of proppant variables yielded the highest fracture conductivity. Out of the four sizes of proppant tested, it was found that 20/40 mesh sand yielded the best fracture conductivity, 200 md-ft, using a constant proppant concentration of 0.2 ppg, and a total proppant mass of 200,000 lb. Data from the actual fracture treatment used on the subject well was also entered into the simulator in order to estimate the results of that treatment. It was found that the 1.0 ppg proppant concentration and 303,163 lb of total proppant mass only yielded a fracture conductivity of 17 md-ft, using 100 mesh sand. Discrepancies in the required amount of sand calculated by the simulator and the actual amount pumped into the subject well indicate that some error exists in the data set. Most likely, the assumed rock properties and/or certain assumptions used in the simulator are not quite accurate.

Introduction

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Theory and Definitions

Hydraulic fracturing is a method of stimulating hydrocarbon production from wells in low to moderate-permeability reservoirs. By injecting fluid down the wellbore at high pressures, a fracture is created and propagated in the reservoir. The fracture acts as a conduit for the flow of formation fluids from the rock matrix to the wellbore. It is particularly necessary in tight gas plays like the Marcellus shale because the naturally occurring reservoir permeability is too low to allow an economic rate of hydrocarbon fluid production.

Several models exist for describing how a hydraulic fracture will propagate in a reservoir with respect to certain parameters. There are the PKN, KGD, and three-dimensional models, as well as others. Each one describes fracture width, height, and length and accounts for fluid leakoff, proppant transport, and other phenomena in different ways and with varying levels of complexity. The major simplifying assumption of the PKN and KGD models is that the created fracture will stay within the pay zone or between some other pre-determined boundaries. Because of this simplification, fracture geometry calculations using the PKN and KGD models can be done quickly by hand. However, three-dimensional models are more complex and require a computer to simulate fracture behavior. They also require extensive rock-property data for the pay zone and the formations above and below it. The benefit of three-dimensional modeling of a hydraulic fracture is that it shows how the fracture evolves with time and space in all three dimensions by taking into account the elastic behavior of the rocks encountered (Freeman, 2009). Meyer's MFrac software, a three-dimensional simulator, was used for this study.

Knowing the rock properties of the reservoir and the formations surrounding it is crucial to understanding how the well will respond to a given fracture treatment. In-situ stress, Young's modulus, Poisson's ratio, and fracture toughness must be known in order for the simulator to accurately predict how a fracture will propagate. Formation permeability and leakoff coefficient are important for determining how efficient the fracturing fluid will be at creating and extending the fracture. This data can be correlated from logs or generated in a laboratory, but often engineers derive standard values for these properties based on their experiences. The rock properties of three layers were considered in this study. These layers were, from top to bottom, the Angola shale member, the Marcellus shale, and the Onondaga limestone.

Fracturing fluid is used to transmit pressure for opening and extending the fracture in the formation. It also serves to transport proppant along the fracture length. They can be water-based, oil-based, acid-based, foam, or gel, depending on the needs of the operator. One of the most important characteristics of a fracturing fluid is viscosity, because it promotes fracture width and aids in proppant transport. The viscosity of a fluid can be increased by the addition of polymers like GUAR, a naturally occurring material (Freeman, 2009). Other considerations for a fracturing

fluid are that it maintains low friction pressure during pumping, provides fluid-loss control, can be “cleaned-up” from the formation after propping the fracture, is compatible with formation fluids, and is economical to use. This study only considered the use of slickwater, a water-based fracturing fluid that has been treated with a friction reducer such as potassium chloride. Slickwater is currently the most common type of fracturing fluid used in the Marcellus shale because it is readily available and relatively inexpensive (Arthur, 2008).

Proppant refers to particles that are transported by fracturing fluid into a hydraulic fracture in order to hold it open after the fracturing fluid is flowed-back to the surface. It is categorized according to material and mesh size. Natural proppants, like sand, are mined from the earth, while synthetic proppants, like sintered bauxite, are man-made to meet special needs. Some synthetic proppants can withstand extreme pressures, exceeding 10,000 psi, and are highly uniform in shape (Economides et al, 1994). Natural sand products have a lower resistance to crushing and feature more irregularities in shape, but they are much less expensive and more widely available. Because extreme pressures are not typically encountered in the Marcellus shale, only natural sand proppants were considered in this study. Mesh size refers to the particle size distribution of proppant grains. Mesh size is notated with a fraction, which increases as grain diameter decreases. For example, 12/20 proppant is smaller in diameter than 20/40 proppant.

Besides coming in various sizes, proppant can also be used in varying concentrations, that is, the number of pounds of proppant suspended in one gallon of fracturing fluid. The concentration of proppant in the fracturing fluid is related to the concentration of proppant in the fracture, which is in turn related to the fracture conductivity. Therefore, in order to make the well as productive as possible, it is important to use the right concentration of proppant in the fracturing fluid.

In this study, the effectiveness of a hydraulic fracture treatment was based on the resulting fracture conductivity, F_{CD} . Fracture conductivity is defined as:

$$F_{CD} = k_f * w$$

where k_f and w represents the permeability and average width of the propped fracture, respectively (Meyer 2008). The result of increasing F_{CD} is that formation fluids enter the wellbore at a higher volumetric rate at a given difference between reservoir pressure and bottomhole flowing pressure. Therefore, higher dimensionless fracture conductivity indicates a more successful hydraulic fracture treatment, in terms of the incremental increase in hydrocarbon production.

Methods

The well used as the basis of this study is an actual Marcellus shale vertical well drilled in West Virginia (Beardmore, 2009). The well was modeled as a three-layered system, as shown in Figure 1 below. The depths of each layer were taken from the subject well. The rock properties used for each layer are standard values supplied by a company that actively drills the Marcellus shale (Arnold, 2009). A summary of some of the most important rock properties for each zone is given below in Figure 2.

The simulation consisted of calculating the conductivities of fractures created with slurries of varying proppant concentration. The corresponding total proppant mass was also calculated. Several fracture treatment parameters had to be assumed and held constant throughout the series of simulations (Arnold, 2009). These assumptions are summarized below in Figure 3.

After constructing plots of fracture conductivity and total proppant mass vs. end-of-job proppant concentration, an approximate average value of fracture conductivity was chosen for each proppant size. Then a value of proppant concentration which corresponded to a relatively low total proppant mass while yielding a fracture conductivity near the average was chosen. This represents the optimum balance between cost, which increases with total proppant mass, and well performance, which increases with fracture conductivity.

Zone	Depth Interval (TVD)
Angola shale	4997'-5967'
Marcellus shale	5967'-6047'
Onondaga limestone	6047'-6257'

Figure 1 - Three Layered System

Zone	Formation Permeability (md)	Young's Modulus (psi x 10 ⁶)	Stress (psi)	Poisson's Ratio	Fluid Leakoff Coeff. (ft/min ^{1/2})
Angola shale	-	2.9	6564	0.19	0
Marcellus shale	0.025	10.5	6047	0.25	0
Onondaga limestone	-	12.0	6883	0.30	0.0004

Figure 2 - Important Rock Properties

Perforated Interval	5950'-6028'
Fluid Type	lickwater (1 gal/1000 friction reducer)
Proppant Type	Natural Sand
Pump Rate	90 bpm
Slurry Volume	1,100,000 gal (26,000 bbl)
Initial Proppant Concentration*	0.2 ppg
*Except when ultimate concentration < 0.2 ppg	
Incremental Proppant Concentration	0.2 ppg
lin. Concentration/Area for Propped Frac	0.75 lb/ft ²

Figure 3 - Simulation Constants

Data and Results

Four different mesh sizes of proppant were evaluated using the simulator: 100, 16/30, 20/40, and 12/20. The plots in Figure 4 summarize the relationship between end-of-job proppant concentration, total proppant mass, and fracture conductivity for each proppant mesh size.

Figure 5 shows the optimum end-of-job proppant concentration and corresponding fracture conductivity and total proppant mass for each proppant size, based on the plots above.

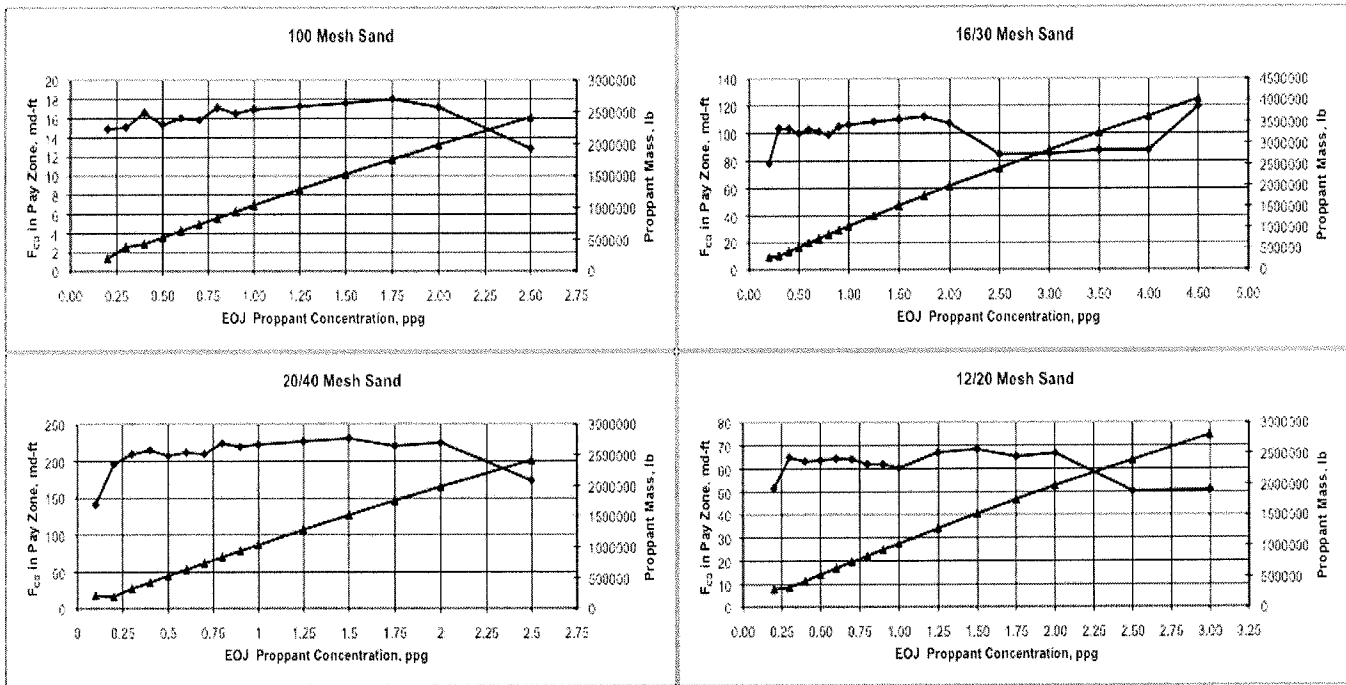


Figure 4 – F_{CD} and Total Prop. Mass vs. EOJ Prop. Conc. for Various Proppants

Mesh Size	"Average" F_{CD} (md-ft)	EOJ Prop. Conc. (ppg)	Total Prop. Mass (lb)	Actual F_{CD} (md-ft)
100	17	0.4	500,000	16.5
16/30	105	0.3	250,000	105
20/40	220	0.2	200,000	200
12/20	63	0.3	250,000	65

Figure 5 – Optimum Conditions for Each Proppant Size

Conclusions

The actual fracture treatment employed on the subject well used 100 mesh sand with an end-of-job proppant concentration of 1 ppg. The total amount of proppant pumped was 303,163 lb. Using the plot for 100 mesh sand in Figure 4 to correlate, the resulting fracture conductivity is 17 md-ft. However, also notice that Figure 4 indicates a required total proppant mass of nearly 1,000,000 lb of proppant. This is much greater than the 303,163 lb that was actually pumped. The difference in calculated and pumped values is probably due to errors in the assumed rock properties from Figure 2 or in the simulation constants from Figure 3.

As shown in Figure 5, the highest fracture conductivities are generated when 20/40 mesh sand is used. Using a constant proppant concentration of 0.2 ppg, a fracture conductivity of 200 md-ft is generated. It is interesting to note that the total amount of proppant required, 200,000 lb, is less than what was actually pumped on the subject well. While the discussion in the previous paragraph indicates there may be a substantial amount of error in the simulations, it seems likely that better fracture conductivities could be achieved, while using a smaller mass of proppant, if 20/40 mesh sand was used instead of 100 mesh sand. Figure 6 below is a comparison of the actual fracture treatment used on the subject well and the optimum treatment found using the simulator.

	<u>Actual</u>	<u>Optimum</u>
<i>Proppant Mesh Size</i>	100	20/40
<i>EOJ Slurry Conc. (ppg)</i>	1.0	0.2
<i>Total Proppant Mass (lb)</i>	303,163	200,000
<i>F_{CD} (md-ft)</i>	17	200

Figure 6 – Comparison of Actual and Optimum Treatments

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