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Increasing Hydraulic Fracturing Success Ratio through Friction pressure management

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Abstract

Hydraulic fracturing operation requires high-pressure system to open the fracture in formation and delivers a number of proppant to be placed in. It has to counter minimum in-situ stress of formation, its tensile strength and friction pressure along the tubing (fracturing string) and near wellbore. Based on hydraulic fracturing job statistics in KS field, friction pressure is consuming up to 70% of the total pressure system. This huge number has to be managed to prevent operational problem in the execution and ensure that treatment designed can be delivered properly to increase the success ratio of the oil production result.

Evaluation of previous hydraulic fracturing job concluded that friction pressure along the tubing and near wellbore affect to the high surface treatment pressure and frequently close to the kick off pump pressure. Thus, pumping rate and maximum proppant concentration have to be limited and the fracturing fluid type also has to be adjusted. Therefore, some efforts have been established to decrease the friction pressure such as changing packer type that allowed increasing the tubing size but still fit to the current completion and changing the perforation method from explosive gun to the non-explosive abrasive jetting.

The results are very promising and affect to the total system pressure. By changing the packer type, it's allowed to increase tubing diameter so that the friction in the tubing decreased to one-third of the previous tubing friction. The near wellbore friction decreased to one-fourth by changing the perforation method. These significant decreases of friction pressure yield the lower surface treatment pressure. Thus, fracturing treatment can be optimized to increase oil production. Moreover, the chance of early screen out can be minimized.

Introduction

KS Field

KS field is located onshore in the Rimau block which approximately 60 km to the northwest of Palembang city, South Sumatra (Figure. 1). The field was discovered in 1996; the main objective reservoir is BRF though all KS wells are penetrated TLS as well. In contrast to the BRF and TAF, TLS has relatively low resistivity (approximately 3 to 7 ohm). Even though the Telisa is a low-resistivity zone, it is a proven hydrocarbon-bearing sand.

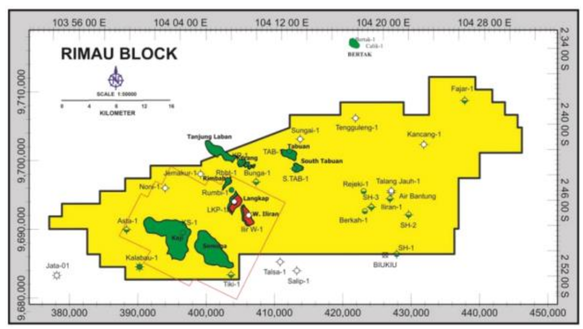


Figure 1-Rimau Block

Production in TLS started in 2002 by successful hydraulic fracturing. The result showed that TLS in KS field confirmedgood productivity with fracture methods. The structure represents two oil and gas accumulations with depth about 2,400 – 2,700 ft subsea.

Hydraulic Fracturing

The purpose of hydraulic fracturing is the placement of an optimum fracture of a certain geometry and conductivity to allow maximum incremental production (over that of the unstimulated well) at the lowest cost. This process combines the interactions of fluid pressure, viscosity and leakoff characteristics with the elastic properties of the rock.

The subjects on the essence of the process, fundamental rock mechanics, and fluid and proppant mechanics demonstrate the influence each component of the operation has on the resulting fracture. An understanding of the fracturing process provides the necessary foundation for the design and implementation discussions. The proppant design subject presents a procedure for conducting a design, and guidelines for design choices. Using the fundamentals of the process and the proppant frac design as building blocks, the essential differences needed for acid fracturing are presented. The subjects of field implementation and diagnosis alert the participants to the types of equipment available in the field and some of the procedures and practices available to help convert good fracture design into a successful fracture treatment.

As shown in figure 2, pressure term that usually used in hydraulic fracturing is below:

- STP (Surface Treating Pressure): Treatment pressure while fracturing job that reads out form surface sensor.
- Friction Pressure (P friction): The friction that occurred while pumping some amount of fluid at specific rate while fracturing job. It's contributed by tubing friction and near wellbore (NWB) friction. NWB friction consists of perforation friction and tortuosity.
- BHP (Bottom Hole Pressure): Treatment pressure while fracturing job that can be reads out form downhole sensor or calculated from other parameters as Equation 3.

$$BHP = STP + P\ hydrostatic - P\ tubing\ friction$$
Eq.1

- ISIP (Instantaneous Shut In Pressure): Instantaneous stabilize pressure after shut down pumping while fracturing job. The difference between STP and ISIP is indicating the friction pressure occurred in the tubing (frac string) and near well bore.

$$ISIP = STP - P\ friction$$
Eq. 2

- Breakdown Pressure: Pressure needed to initiate fracture in the formation. It can be acquired by conducting breakdown test or mini fall off test. Breakdown test can be implemented by pumping at low injection rate (<1 BPM). Breakdown pressure is indicated by suddenly decreased of pressure after gradual increasing.
- Closure pressure: Pressure that indicate formation fracture closure after injected above the fracture pressure.

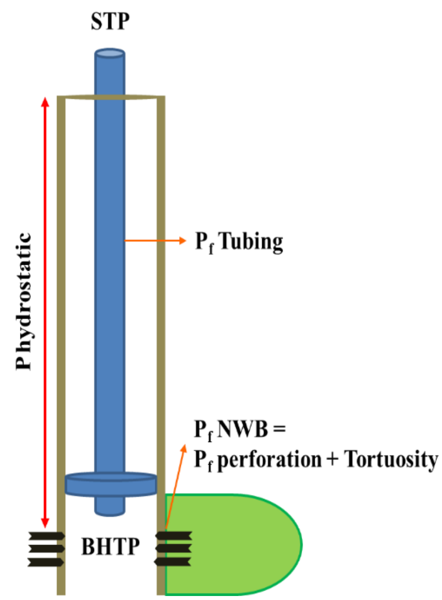


Figure 2-Typical wellbore configuration

Tubing Friction

Friction is an energy loss (actually measure it as a pressure loss) due to viscous shear of the flowing fluid. In a fluid, molecules are free to move past each other but there may be a little resistance. This resistance is due to shear forces which must be overcome.

In a single phase fluid, most of the liquid is moving along together so there is not much shear in the liquid itself and this friction can usually be ignored.

The walls of the pipe, however, will tend to "stick" to the fluid so shear forces between the pipe and the fluid can be quite large and increase as the velocity of the fluid increases. The amount of friction present can be represented by a "friction factor" - f . Given "f" we can calculate the pressure loss from the following:

$$\Delta P = \frac{f \rho v^2}{2 g_c d}$$

Eq.3

Where:
ΔP = pressure loss
ρ = fluid density
v = fluid velocity
gc = gravity constant
d = pipe diameter

As the pipe diameter increases, the velocity, v, decreases by the square of the diameter change so it is reduced drastically. These two factors make an increase in pipe diameter have a large impact on decreasing the frictional pressure losses. Figure 3 describes graphical information about the tubing friction pressure based on tubing size.

Figure 3-Tubing Friction Losses

Near Wellbore Friction

NWB friction consists of perforation friction and tortuosity. Step down test prior to main fracturing is used to quantify perforation and near-wellbore pressure losses (caused by tortuosity) of frac'd wells, and as a result, provides information pertinent to the design and execution of the main frac treatments. Step-down tests can be performed during the shut-down sequence of a fracture calibration test.

To perform this test, a fluid of known properties (for example, water) is injected into the formation at a rate high enough to initiate a small frac. The injection rate is then reduced in a stair-step fashion, each rate lasting an equal time interval, before the well is finally shut-in. The resulting pressure response caused by the rate changes is influenced by perforation and near-wellbore friction. Tortuosity and perforation friction pressure losses vary differently with rate. By analyzing the pressure losses experienced at different rates, we can differentiate between pressure losses due to tortuosity and due to perforation friction.

Pressure drops across perforations and due to tortuosity are given mathematically by the following equations:

$$\Delta P_{perf} = k_{perf} q^2 \quad \text{(a)}$$

$$k_{perf} = \frac{1.975 \gamma_{inj}}{C_d^2 n_{perf}^2 d_{perf}^4} \quad \text{(b)}$$

$$\Delta P_{tort} = k_{tort} q^{\alpha} \quad \text{(c)}$$

Eq. 4

Where:
Δp perf = Perforation pressure loss, psi
Δp tort = Tortuosity pressure loss, psi
Q = Flow rate, stb/d
k perf = Perforation pressure loss coefficient, psi/(stb/d)^2
k tort = Tortuosity pressure loss coefficient, psi/(stb/d)^2
γ inj = Specific gravity of injected fluid
C d = Discharge coefficient
n perf = Number of perforations
d perf = Diameter of perforation, in
α = Tortuosity pressure loss exponent, usually 0.5

For step-down tests, it is essential to keep as many variables controlled as possible, so that the pressure response during the rate changes is due largely to perforations and tortuosity, and not some other factors. It is recommended to maintain relatively short periods for each injection rate, so that the frac remains substantially the same for each injection period. Short injection periods also help prevent the frac from closing prematurely before the test is complete. When the injection rate is changed, the pressure does not change in a stair-step fashion; it takes some time for pressure to stabilize after a change in rate. To make sure the effect of this pressure transition does not obscure the relationship between the injection rate and pressure, injection periods of the same duration are used.

Step-down test analysis is done by plotting the pressure / rate data points with the same time since the last rate change on a pressure-rate plot, and matching the pressure loss model (given by the equations above) to these points. On the basis of the model, the perforation and tortuosity components of the pressure loss are calculated, and the defining parameters are also estimated.

The basic procedure for this type of test is illustrated in the figure 4. Rate is stepped down fairly quickly, typically dropping rate to a lower level, monitoring pressure for about 5 to 10 seconds until pressure somewhat stabilizes, and then dropping rate to the next lower level. Doing this quickly is essential for a true indication of total downhole friction. Slow rate changes can allow significant changes in pressure outside the wellbore, thus disguising the result.

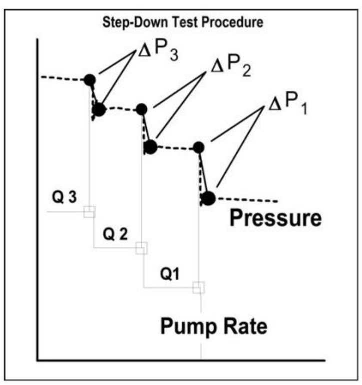


Figure 4-Typical Step down test

The data is analyzed by plotting friction (on the "y" axis) versus pump rate. For the case illustrated above, one would plot the total friction as $(\Delta P_3 + \Delta P_2 + \Delta P_1)$ versus Q3, and then plot $(\Delta P_2 + \Delta P_1)$ versus Q2, and finally ΔP_1 versus Q1. Then, it's plotted on log-log scales as illustrated in figure 36. It is usually best to pump the step-down test using the same fluid as planned for the final stimulation treatment, a completely separate gel injection is normally required for moderate to high fluid loss formations.

Data and Method

In order to increase the success ratio of hydarulic fracturing job, comprehensive evaluation and procedure have been established to find the root cause of the high frictionin the pressure system of hydraulic fracturing. The method is summarized below:

1. Evaluation of hydraulic fracturing job success ratio. Based on historical data, most of hydraulic fracturing job that were failed due to high STP frequently close to the kick off pump pressure. It was suspected caused by high friction pressure. As the result, umping rate and maximum proppant concentration have to be limited and the fracturing fluid type also has to be adjusted.

2. Install additional measurement tool to obtain reliable data about the pressure system in hydraulic fracturing.

   Additional measurement tools proposed is donwhole gauge as shown in figure 6 & 7. In this case, sourcing tools and equipment to service provider related are needed. On the other hand, looking own resources and feasibility to build the tools in-house and its operating procedure are also considered.

Figure 5-Downhole gauge carrier

Figure 6-EMR as downhole pressure survey

3. Evaluate the obatianed data and find the root cause.

   The total friction pressure in hydraulic treatment can be calculated using equation 2. Based on 12 wells that were analyzed as shown in figure 7, averate friction pressure is about 65% of the Surface Treating Pressure.

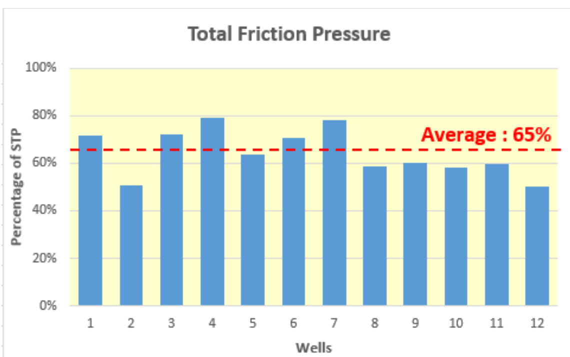


Figure 7-Total Friction Pressure

4. Establish procedure as efforts to reduce the friction system both tubing friction and near wellbore friction. The procedure are:

   a. Increasing ID tubing. As stated in Equation 3, increasing ID tubing leads to decrease the tubing friction. The well configuration, tubing weight for setting packer and material stock in the warehouse has to be considered. In casing 5.5", the option availabe is 2-7/8" tubing, 2-3/8" tubing, 3-1/2" Drill Pipe and 2-7/8" Drill Pipe. Previously, DP 2-7/8" (with ID 2.151") is used because of the requirement of tubing weight for setting packer. It leads to high friction pressure in the tubing. Then, in order to increase the ID by using tubing 2-7/8", the packer type has to be changed to tension packer with mechanical setting. By this packer, the ID tubing is bigger (2.441") and able to reducet the tubing friction.

   b. Increasing entrance hole diameter (EHD) perforation. As stated in Equation 4(a), increasing EHD perforation can decrease the perforation friction. Again, the well configuration and material stock in the warehouse has to be considered. As described in Table 1, EHD comparison between type of gun is evaluated using software Engineering Perforator Analysis (EPA) and product catalog.

Table 1-EHD comparison

Gun Type	Casing Size (inch)	EHD min (inch) - Centre
Through Tubing BH 1-11/16"	5.5	0.26
	7	0.23
Through Tubing BH 2-1/8"	5.5	0.43
	7	0.35
Casing Gun GH 3-1/8"	5.5	0.41
	7	0.23
Sand jet Perforator	**5.5**	**0.46**
	7	**0.43**

5. Implement the procedures and evaluate the result whether any improvement or not.

6. Establish standart procedure to reduce the friction pressure for the future of hydraulic job.

Result and Discussion

Tubing Friction

After changing packer type into mechanical set packer which is not required high tubing weight to set, the tubing configuration for hydraulic fracturing job can be changed to the lower ppf tubing. Lower tubing ppf, will leads to higher ID. While using hydraulic set packer, the tubing used for hydraulic job have to be higher ppf. For well with casing 7", it needs to use DP 3-1/2" tubing and for well with casing 5.5", the available option is only DP 2-7/8”. After packer changes, the use of tubing 2-7/8” (with lower ppf compared to drill pipe) become allowable both for well with casing 7” and 5.5”. It significantly reduce the pressure friction loss in the tubing up to 60% in well with casing 5.5”. Figure 8 describes the comparison of tubing friction of DP 3-1/2”, DP 2-7/8” and tubing 2-7/8”. The friction pressure between DP 3-1/2” and tubing 2-7/8” is comparable. Tubing 2-7/8” is slightly lower than DP 3-1/2”. Tubing 2-7/8” is still preferable becase it’s easier than DP 3-1/2” in the installation.

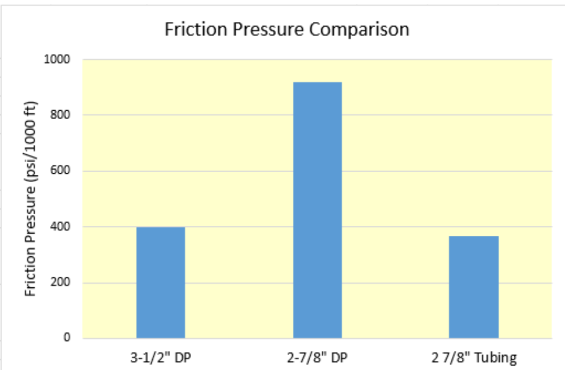
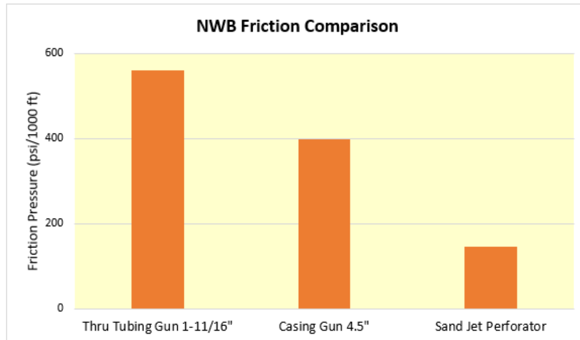


Figure 8-Friction pressure comparison

NWB friction

As previously stated, NWB friction consists of perforation friction and tortuosity friction. Method to decrease perforation friction is by using gun perforator with bigger EHD or using sand slug while execution of main fracturing job. On the other hand, method to decrease tortuosity friction is using oriented gun perforator and it should be shooted paralel with the maximum horizontal stress. This method is more expensive so that is not prefered. This paper discuss how to minimize the NWB friction by using gun with bigger EHD.

Each type of gun and method has been tried in KS field. The lowest NWB friction is resulted by sand jet perforator. Sand jet perforator requires coil tubing unit (CTU) to deploy and utilize sand (as abrassive agent) with gel fluid to make the hole in the casing. The NWB of sand jet perforator is even lower than big casing gun 4.5”. Meanwhile, Thru tubing 1-11/16” yields the highest NWB and it should be avoided especially for high inclination well. It will limit the pump rate and the proppant concentration while main fracturing job. The worse case is early screen out could happen and make the entire hydraulic fracturing job will failed.



Hydraulic Fracturing Success Ratio

In 2017 and 2018, the maximum success ratio of hydraulic fracturing job is about 80%. Most of the failed job is caused by high STP that very close to the kick off pressure. It also leads to early screen out. Early screen out occurred when the STP is suddenly increase significantly so that the pressure exceed kick off pressure. The proppant can not be injected anymore due to proppant bridging in the wellbore. This will impair to the production performance.

In the early 2019, the improvement has been established and applied. It consist of changing the packer type, running tubing with bigger ID and using perforator gun with bigger EHD. The result is quite encouraging. The success ratio in 2019 job increase to 100%. So far, there are no failed job in 2019. Table 2 represents the success ratio of fracturing job from 2017 – 2019.

Table 2-Hydraulic fracturing success ratio

Year	Number of Job	Job Failed	Success Ratio
2017	20	4	80%
2018	14	4	71%
2019	6	0	100%

Conclusions

Hydraulic fracturing job improvement through friction pressure management shows good result. All of the improvement can be summarized below:

1. Changing the packer type for hydraulic fracturing job enables the usage of lower ppf tubing with bigger ID and leads to reduction of tubing friction up to 60%.
2. Sand jet perforation method yield the lowest NWB friction among the other type of gun perforated that have been applied in KS field.
3. Success ratio of hydraulic fracturing job in KS field increased up to 100% in 2019.

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