GEOLOGICAL CHALLENGES IN HYDRAULIC FRACTURING OPERATION: A CASE STUDY IN UNDISCLOSED PETROLEUM FIELD IN OMAN

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ABSTRACT

Production of hydrocarbons is hampered by obstacles known as formation damage. This damage needs to be removed or bypassed to retain well productivity. Hydraulic fracturing stimulation is one of the techniques used to overcome formation damage and enhance the productivity of the formation by maximizing the ultimate recovery. It was highlighted that there are some challenges associated with this technique and the most difficult challenges in hydraulic fracturing design and implementation are those related to geology of the reservoir. This study was, therefore, aimed at addressing the main geological challenges and providing the best low-cost solution and practice that leads to easy and successful stimulation operation. As an engineering solution in this study, fracturing geometry design was addressed to overcome geological challenges using advance simulator tool. Multiple fracking design by using computer simulation for a set of geological parameters aid on predicting the result out and avoid any complication in future production. Other challenges addressed by intelligent numerical evaluation used as a best practice in well stimulation to maximize the benefits of well production recovery. Optimizing fracturing fluid is also an important element covered in this study. An investigation was conducted on formation permeability variation for heterogeneous rock formation as one of the geological challenges faced by hydraulic fracturing operation for further understanding the geometry of fracturing for the success of stimulation operation. By fixing all other formation and pumping variables it was observed that formation permeability influences the length of fracture geometry, which could lead to stimulate out of pay zone.

Keywords: *hydraulic fracturing, geology, fracking, treatment fluid, geological challenges, frac treatment*

INTRODUCTION

Petroleum products and natural gas provide a higher percentage of the world energy demand recently [1]. Following the drilling of the well to the final depth where the hydrocarbons accumulate, the well needs to be turned to production stage for the purpose of getting cash flow from extracted black gold and compensate the drilling cost. Some of the wells deliver hydrocarbons easily and others are not and as a result they need treatment called Well Stimulation [2]-[4]. The rock formation which should produce hydrocarbons has in natural bulk of rock with voids/pores between rock grains. The pores store some hydrocarbons in both liquid and gas phases. In many instances, production of hydrocarbons was hampered by obstacles known as formation damage in the petroleum industry. This damage blocks voids which are close to the wellbore. Consequently, the needs of hydraulic fracturing stimulation are to bypass the damaged region and induce new paths to succour the flow of hydrocarbons from rock formation to wellbore [5].

Hydraulic fracturing is a technique of injecting fluid mixed with additives at both high rate and pressure inside reservoir formation to create paths [6]. Statistics show that the oil extracted with hydraulic fracturing techniques could be enhanced by about more than 51% of the crude oil produced from treated wells [7]. Most of the additives in hydraulic fracturing are naturally extracted and used to enhance the properties of the treatment fluids. In some type of hydraulic fracturing, an extra material called "proppant" could be pumped with the slurry to prevent fractures from close. The productivity gained from hydraulic fracturing stimulation can also sustain for period. A study stated that 25% of porosity of proppant-pack can sustain up to 40 days in well temperature of 300°F with closure stress of 6000 psi [8].

Besides the huge production gain from this type of stimulation, the cost of this technique is relatively high and, in some cases, it makes up about 14- 41% of well's total cost. The difficulties of pumping fracturing fluid in geological challenges such as in-situ stress of formation can raise the consumption of frac pump horsepower. The more consumption of horsepower the more cost would be. Besides, the number of stages, chemical usage and fluid volume will impact the total cost. Subsequently, there would a need to maximise the benefits obtained from hydraulic fracturing by performing better stimulation execution.

There are some challenges faced prior to treatments. Some of them relate to geomechanics and others correspond to fluid treatment design [9]. In some instances, though operations are successful, productivity might not be as expected because of the treatment slurry design [10]. In-situ stress, low porosity, low permeability, high variation in pore pressure, high fracture gradient, extreme formation temperature are the significant challenges in deep wells [11]. High variation in confined rock stress influence the fracturing strategy perforation spots location as well as the completion of the well. Developing tight gas reservoir is very critical. Formation stresses can be superior at deep wells ranging from 4000-5000 m. Fracturing tight formation requires successful initial propagation that depends more on formation stresses. A core sample is important to analyse rock geomechanics to know the magnitude of in-situ stresses [12].

Temperature is a critical factor in designing hydraulic fracturing fluid. By wireline operation, a logging tool runs into the well to record formation temperature for hydraulic fracturing treatment design. This tool has difficulties to read temperature ranging 160-190°C and it sometimes fails [9].

Inducing fracturing in formation requires pressure to overcome the in-situ formation stress. Sometimes it is quite hard to create fracturing because of the overstressed formation and the limitation of surface equipment especially when pumping high viscous fluid inside formation throw perforation. In this case, hydraulic fracturing engineers would look in the possibility to have lower friction pressure and implement it in fracturing propagation [13]. Hydraulic fracturing treatment design is also one of the challenging factors in the stimulation process. The fluid must be stable during the injection period for successful proppant transportation inside treating pipeline wellbore and formation. and this can be difficult in HPHT wells [14].

Poor carrier fluid viscosity can also lead to unsuccessful fracturing treatment placement inside the formation. Fluid should provide sufficient suspension to transport proppant inside open fracturing. If the viscosity is not enough, bridging will occur inside the wellbore and blocks the perforations and latterly causes screen out [15]. Geological challenges are the most difficult challenges in hydraulic fracturing design and implementation. Many of hydraulic fracturing jobs can end up with unsuccessful treatment due to geological characteristics of formation, surface equipment and well completion limitation. It is a sophisticated process that requires a high level of professionalism and competence to do a successful fracturing job. The objective of this study is, therefore, to investigate the main geological challenges and provide the best low-cost solution and practices that lead to easy and successful stimulation operations.

METHODOLOGY

Many field blocks could be very challenging in terms of geology since the formation might be heterogeneous and the block is faulted and has many natural fractures as well. Hydraulic fracturing stimulation is also one of the challenging designs in the well life cycle. Fracturing shallow depth reservoir can cause sometimes an increment in water production which is unwanted in well economics and it could harm the aquifer if the design does not implement carefully.

Oil well has been selected as a case study in Oman field, 91°C, low reservoir pressure of approximately 1400-2000 psi, with stimulation of Acid fracturing technique. The formation thickness which needs to be stimulated was in the range of 25-40 m. Most of the geological challenges can be addressed by hydraulic fracturing design based on advanced design simulator. It was utilised designing tool to do multiple evaluations on the formation parameters to understand and figure out the effect of those parameters on overcoming faced challenges.

Along with utilising the latest technology in stimulation design, an eye-ball evaluation is a crucial element to understand the geology interpretation and predict any upcoming challenges that may occur and ensure the readiness of solution to be implemented.

Numerical analysis was used in this study to evaluate stimulation cost-effectiveness prior to stimulation operation implementation. The cost of the treatment was evaluated including materials and tools following the treatment fluid optimization to attain the best treatment plan. The key to understand and overcome hydraulic fracturing operation challenges is to utilize all methods of evaluation correctly. Such a thing will aid uncovering the best solution. Since the selected field reservoir formation is suffering from in-situ stress variation, it means there is also a chance of formation layering and this has been observed as formation challenge in the field. This also gives an in-situ variation of porosity and permeability. The terms are playing a big role in fracture length design.

RESULTS AND DISCUSSION

Figures 1-4 show the effect of permeability on the fracture half-length geometry. When permeability increases the half-length of fracturing tends to be shorter and vice versa. Figure 1 shows that for low formation permeability (5 md), the geometry expected of half-length will be longer than higher permeability.

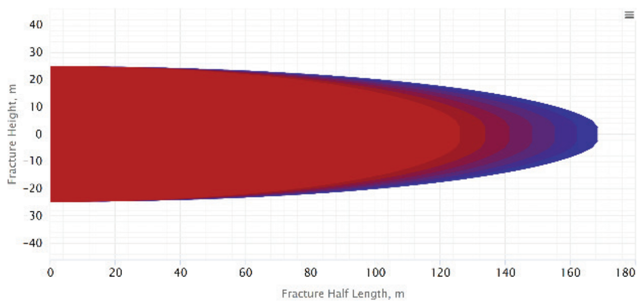

Figure 1 Formation permeability (5 md) vs fracture half length (168 m)

Figure 2 shows formation permeability versus fracture half-length when permeability magnitude changed to 10 md. It was observed that permeability increment affects shortening the fracture length geometry.

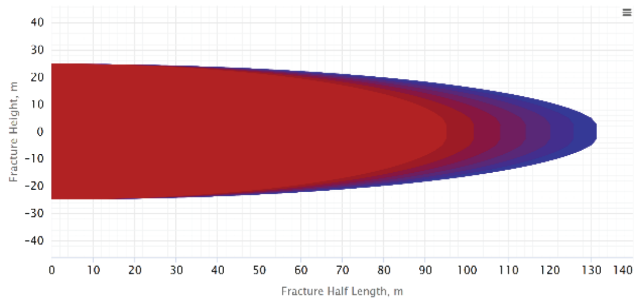

Figure 2 Formation permeability (10 md) vs fracture half length (132 m)

Figure 3 shows formation permeability for fracture half-length when permeability magnitude changed to 15 md. It was observed that when the permeability was made higher, the half-length became shorter.

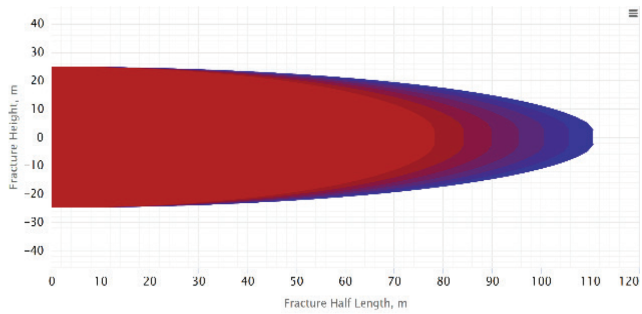

Figure 3 Formation permeability (15 md) vs fracture half length (111 m)

Table 1 explains the variation in fracturing half-length in terms of formation permeability while the rest of the formation parameter and pumping parameter are fixed.

Table 1 Formation permeability vs fracture half-length

Permeability magnitude "k" (md)	Fracture Geometry	
	Half Hight (m)	Half Length (m)
5	25	168
10	25	132
15	25	111

It is obvious from the design, permeability influences the fracture length, when the permeability increases, the fracture length decrease. Therefore, for low reservoir permeability, it can be expected that the fracture geometry takes deeper in the formation section. A graphical explanation of the relationship between formation permeability and fracture half-length is depicted in Figure 4. It was observed that when permeability increases, the fracture half-length decreases.

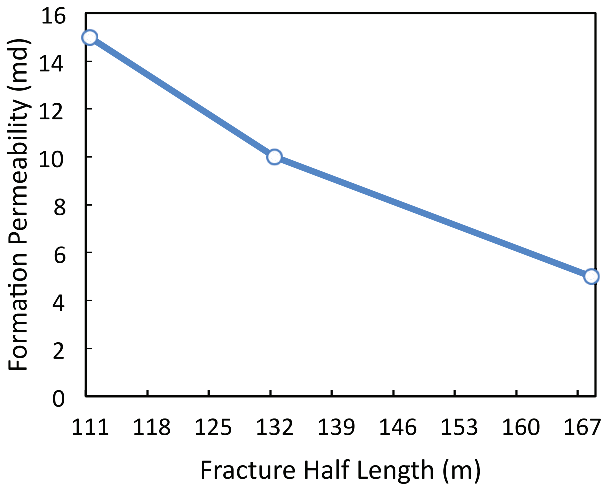

Figure 4 Formation permeability vs fracture half length

Fracture barriers and identifying them is one of the important parameters to control fracture height. Barriers can contain the height and prevent it from growing. The viscosity of fracturing fluid and injection rate also affect the height growth. Both were fixed and thickness of the formation going to be vary based on the below design.

The effect of varying the formation thickness on the fracture height propagation was investigated. Figure 5 shows fracture height versus fracture half-length when the formation thickness was 39 m. Changing the thickness to 69 m on the fracture height versus fracture half-length is also depicted in Figure 6. Both results prove the effect of formation thickness identification in fracture geometry. The design simulator gives different half-height and length for different fracture containment thickness. If the formation barriers are not identified precisely, the simulator will give the wrong interpretation. And unfortunately, this kind of mistake has a very strong impact on the well production and could lead to unwanted water production which will cost additional well treatment cost to get rid of this impact.

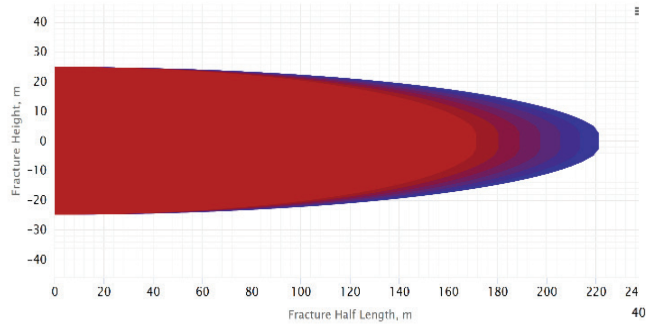

Figure 5 Fracture height vs fracture half length, when formation thickness is 39 m

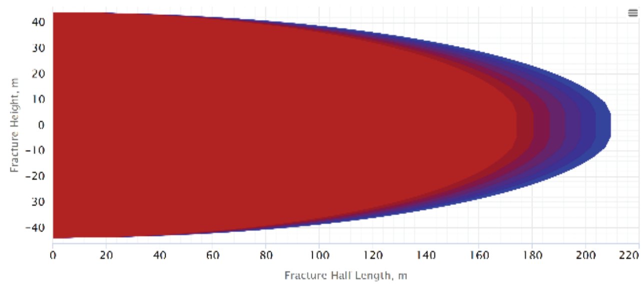

Figure 6 Fracture height vs fracture half length, when formation thickness is 69 m

Table 2 shows that fracture half-height is effected more by formation thickness while the rest of the formation parameter and pumping parameter is fixed. A slight change in half-length has been observed.

Table 2 Formation thickness vs fracture height

Formation Thickness (m)	Fracture geometry	
	Half Height (m)	Half Length (m)
39	25	222
69	45	210

It could be understood that from the design, when the treated formation thickness increase, the height of the fracture geometry increases to fully stimulate the formation. Figure 7 interprets the correlation given by the simulator design between formation thickness variation and the fracture half height.

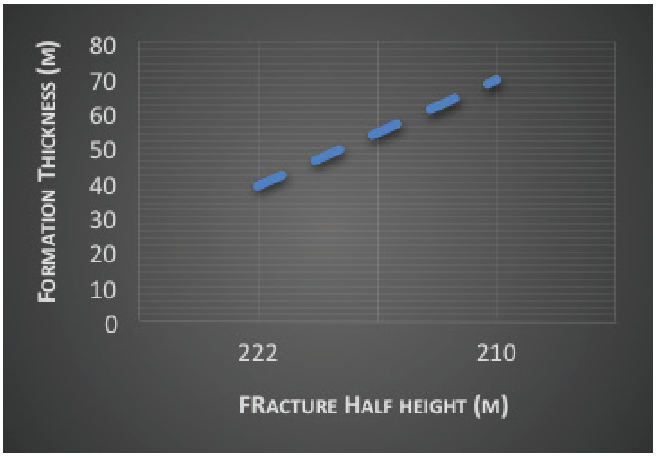

Figure 7 Formation thickness vs fracture half height

As it was observed, formation thickness plays a major role in fracture height geometry. It is quite important to identify formation barrier in frac stimulation design.

Another geometry that can lead to fracking out of the formation thickness is the formation barrier. This happened when the log interpretation failed to identify the fracture containment which is normally accomplished by dens layer of formation "Shale". This is why the FBI (Fracture Barrier Index) method is an important tool to identify where the perforation should be placed and how much the thickness of the formation should be only treated.

Methods of Optimizing Fracture Fluid

As discussed earlier, optimizing fracture treatment fluid has been looked for by the oilfield company. This approach has a big impact on reducing formation damage and treatment cost reduction. It will address the polymer additives used to make the gelation of fracture fluid in terms of formation damage and cost reduction.

The main aim of stimulating well formation is to increase permeability. But in the real field experiment, the treatment fluid used to increase the productivity of the well has an impact on formation damage as well.

Cost Reduction: The cost of hydraulic fracturing varies a lot from one well to another. Stimulating challenging formation could cost a lot. Low Permeability, the over-stressed formation, HPHT formation, large stimulation volume, Fluid and additives types and some other factors are playing a major role in the cost of stimulation. Figure 8 low has the most expensive additives and material used in Hydraulic fracturing stimulation.

Figures 8 and 9 show the differences in terms of cost between the most expensive types of proppant and additives widely used in hydraulic fracturing in Oman. Figure 8 specifically gives an idea about the average cost of each additive relative to the other. Figure 9 illustrates the cost of one proppant type and four types of additives for certain successful Frac jobs conducted in Oman.

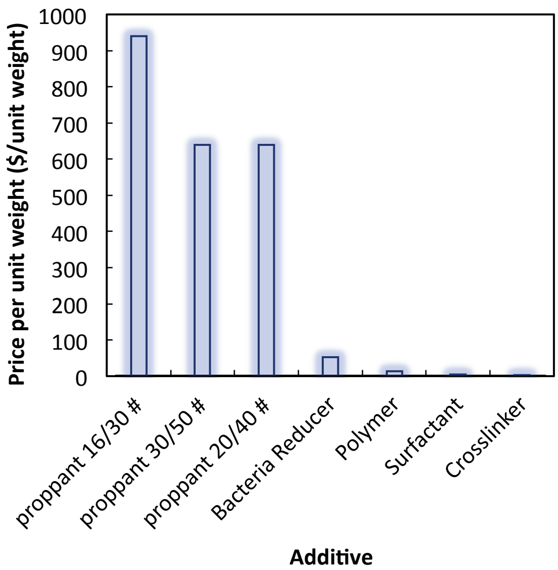

Figure 8 Cost comparison between proppant sizes and four most expensive additives used in hydraulic fracturing stimulation

From Figure 9, Proppant types are the most expensive material used to pump along with treatment slurry. A huge amount of proppant designed to be placed inside the formation. It was observed that in practical stimulation job most of the hydraulic fracturing job failed in proppant pumping stage especially for challenging tight formation. If the job screenout before successful proppant place in the formation, the amount of proppant inside the wellbore, tubing and surface pipe connection will be lost and more cost will be added to the final treatment cost. Careful screenout sign indication needs to be identified earlier.

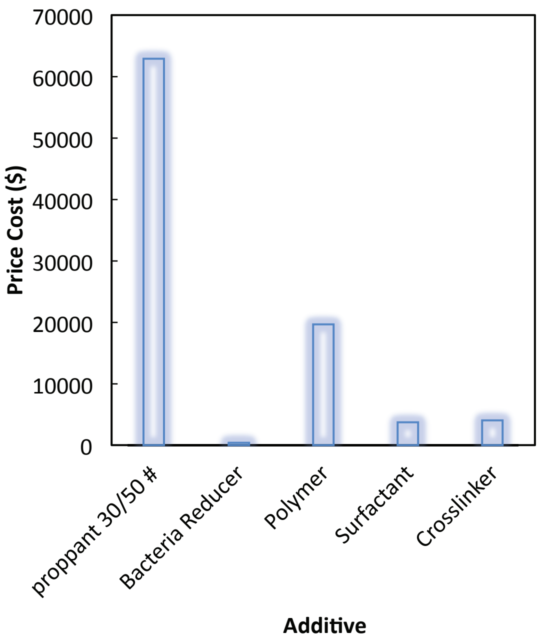

Figure 9 Cost of proppant and four types of additives for a successful small, easy frac job done in oilfield without any geological challenges

Proppant is the responsible material for enhancing the permeability of the formation. Since it is costly, the material should be evaluated from different perspectives to ensure the quality of this material. Roundness and sphericity of proppant effect the permeability of proppant pack, the irregular shape of proppant lower the permeability and if the rate of residual polymer increase too, the proppant pack will be badly affected. Another factor that needs to be evaluated is the crush strength, wrong selection of proppant in a high stressed formation leading to proppant failure and permeability will be affected. Another important factor is the proppant sieve analysis since this analysis ensures that the proppant has a 90% correct size or it is mixed from different sizes. Through experience, some provider has pad proppant quality and that material going to be rejected and discarded from the treatment plan. Proppant should give intensive attention along with the stability of the treatment slurry.

After proppant cost, Bactericide additives comes first but this is going to be used in less amount in job design. In Figure 9 clearly shows that the final cost of Bactericide is the lowest among the other four additives.

Polymer as discussed earlier, optimizing fracturing fluid by reducing the concentration of polymer is an effective method in formation damage & cost reduction. Since the geological challenges associated with fracturing operation has a very strong impact on polymer usage. For HPHT wells, the amount of polymer has to be increased to withstand highly elevated well temperature in turn to sustain the rheological properties of the fracture fluid. On the other hand, a high concentrated polymer in the overstressed formation may cause high friction and more pump horsepower will be consumed and lost. In overall, polymer concentration needs to be optimized carefully for better fluid performance and cost reduction. This is a critical element that needs to be evaluated in the early stage of designing.

Normally, surfactant pumped as a constant rate for mostly all types of wells and it is believed that the fixed concentration which utilized in each job needs to be revised and proved experimentally. Crosslinker additives concentration typically increase with the increase in polymer concentration since this is used to link polymers particles with each other to form semisolid fluid. Obviously, this is also going to be a change in concentration or even the type of additives if geological challenges exist. Some Crosslinker additives are very costly and applied for special formation environment such as very high formation temperature ranges from 300°F and above.

CONCLUSION AND RECOMMENDATION

From the understanding of the geological challenges that could face hydraulic fracturing stimulation, the following solution could be concluded to maximize the benefits of hydraulic fracturing and improve reservoir ultimate production recovery:

For new stimulated field: It would strongly be recommended that any company needs to try this technology to invest on the geological evaluation techniques for the knowledge of the nature of the geology structure and the success of the stimulation techniques. It is obviously each new field development will be unaffected cost in the early stage and the company pay a lot for that.

1. Allowed to conduct further expandable and intensive studies in each stimulation attempt (ex. Log analysis, treatment design, etc) for better understanding the geology nature for a future attempt. Conduction more analysis leads to more chance of success in stimulation.
2. Understanding log interpretation is the first key element of success in hydraulic fracturing stimulation. Understand the logging tool accuracy and evaluate the same in well condition (eg. Some tool attend to lose it is accuracy at high elevated temp) and use of eye-ball evaluation to read log tool data.
3. Run multiple frac design using computer-based numerical simulation design for a set of geological parameters, upper and lower ranges and see how the overall stimulation design will vary. This method helps a lot on predicting the result out and to avoid any complication in production (For example, permeability could be taken as a range, in situ stress, pore pressure etc).
4. Hydraulic fracturing cost should be evaluated before conducting a treatment. Since this type of stimulation is expensive and production gain after stimulation would not compensate for the treatment cost in some cases.
5. Optimizing treatment design is the first step in cost reduction and should be implemented all the time. Large frac geometry design is expensive and not always increase hydrocarbon production but can even cause production problems like water break-through or scale build-up. Optimizing treatment design will also help in reducing formation damage caused by polymer and it is an effective method to reduce the cost of the treatment.
6. Utilize better additives performance to deliver clean frac and reduce the damage within the formation after stimulation to maximize the ultimate recovery of hydrocarbons.
7. FBI (Fracture Barrier Index) is an effective tool to determine the frac containment to not stimulate the unwanted formation and avoid the extent of fracture geometry out of the layer.
8. Careful in selecting and evaluating proppant material for overstressed formation since this is going to affect the permeability of the proppant pack after the treatment. Proppant could cost a lot and needs to ensure pumping high-quality proppant.

ACKNOWLEDGEMENTS

The authors would like to thank the International College of Engineering and Management for the support provided.

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