An optimised Hydraulic Fracturing Treatment on Challenging Rizq Field

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SUMMARY

Hydrocarbon production from unconventional reservoirs is often associated with hydraulic fracturing operations. In many cases however, the high in-situ stresses and complex natural fracture network hinder an effective stimulation process. Therefore, different strategies are adopted to increase the success chance of stimulation. These strategies are in many cases field dependent and thus cannot be extended to other fields. In this study, we demonstrate a new work flow to ensure a successful stimulation process in an unconventional gas field in Pakistan. Well Rizq-01 was drilled as an exploration into challenging PAB formation which is tight sandstone with 0.3mD permeability but highly fractured. Exploration wells in offset fields were drilled and stimulated in the same formation and resulted in screening-out and inability to place enough proppant due to fracture complexity and high in-situ-stresses. To overcome these challenges, extensive petrophysical and geomechanical analysis were performed to introduce a new workflow for stimulation of the formations with similar characteristics. The workflow includes a) Extract extensivewell log information for better understanding of stress barriers, stress magnitude and orientation, Young's Modulus, formation fluid information, other essential petrophysical properties, b) Sensitivity analysis on the hydraulic fracturing treatment including the proppant size, type and volume, and fluid systeme.g. the design was based upon geomechanical and petrophysical interpretations of the openhole log data, and c) Redesign of fracturing treatment process utilizing a first-of-its-kind onsite pre-frac test results, showing its helpfulness in the absence of bottom-hole gauge. The study therefore summarizes the challenges, the work flow implemented, and the lesson learnt for successful stimulation job in Rizq Field.

Key words: Hydraulic Fracturing, Natural Fracture, In-situ stress, Petrophysical analysis

INTRODUCTION

Clark(1949) discussed the first commercial hydraulic fracturing treatment, in which the pumping steps of hydraulic fracturing were, explainedand the production increase was evidenced. Since 1949 more than 2.5 million fracturing treatments have been carried out worldwide. In-fact, it is assumed as of today more than 60% of the wells drilled worldwide are fractured, which has significantly increased the world's hydrocarbon production that otherwise, would have been uneconomical.

A very key development in hydraulic fracturingwas introduced byNolte(1979) who presented the idea of interpretation of pressure decline for getting the estimation of fracture parameter. The idea was later (Nolte and Smith 1981) extended to get more precise measurements of the height growth and to avoid problems like screen out. Later, the same concept was used for the Diagnostic Fracturing Injection Test, also known as DataFrac treatment in which G-function derivative plot, after closure analysis and Step Rate test was used.

On the other hand, one of the major issues was to stimulate a formation with natural fractures, as the fluid functionality in those formations is quite disturbed, this was deeply discussed by Brittet al(1994). To eradicate this problem, large pad volumes and fluid loss additives are pumped. However, this practice is not universally acceptable on all natural fractures and a thorough pre-frac study (including proper MiniFrac treatment) is needed for these formations.

There are however some limitations with MiniFrac tests amongst which the assumption of homogeneous formations are of particular importance as discussed by Solimanet al(1990). The similar limitation has been discussed by Lizaket at (2006) who demonstrated how these tests, mainly step rate test can give erroneous results in the formations with near-wellbore frictions or tortuosity, particularly in the absence of bottom-hole gauge. He mentioned the idea of pumping the step rate test with (Initial Shut-in Pressure) ISIP at the end of every rate to eliminate near-wellbore friction's effect.

Such formations are often encountered in Pakistan where there are excessive natural fractures and high near-wellbore frictions, which is always challenging for a successful hydraulic treatment. One such formation was PAB formation in which the treatment failure rates were high. However, after a thorough study on all the wells fractured previously in the same field, proper investigation of well logging data and DataFrac (MiniFrac) results, it was decided to stimulate the same formation of Rizq-01 through hydraulic fracturing

treatment but with newly proposed methodology explained throughout this work. Interestingly it wasn't only a successful operation but also resulted in enormous increase of production.

METHOD AND RESULTS

In order to have a successful hydraulic fracture treatment on such tight fractured formations, the following step framework was introduced:

Logging Data

Logging Data was analysedfor better understanding of stress barriers, stress magnitude and orientation, Young's Modulus, formation fluid information, etc. The data obtained from the Logging information was used in the pre frac modelling stage as well as optimization of fracturing chemical and proppant volumes. The mechanical properties of the formation were extracted from acoustic logs however no size correction was applied at this stage (Roshan et al 2016, Masoumi2016, Roshan et al 2017).

Three zones of interest were indicated as shown in Figure 1. Two of threezones (lower PAB & Upper PAB) were considered for hydraulic fracturing treatment and the third zone was perforated only.The three zones of interest for the PAB formation are highlighted on the log diagram. The yellow box highlights the Lowest PAB section from 2,940 to 2,961 m. The red section highlighted the Upper PAB interval 2,900 to 2,915 m and the green section for the Upper Most PAB from 2,877 to 2,880 m.

Hydraulic Fracturing Treatment Design

Extensive pre-job evaluation and planning which included review of available logs and previous frac data on the same formation with other wells in Rehman field (Injection treatments, optimization of fracturing chemical and proppant volumes) was conductedto get maximum benefit of this major well stimulation job.

Lower PAB formation

For lower PAB formation pre-fracture flow indicated low gas returns, with limited reservoir pressure.

Break Down Test

To estimate the breakdown pressure and decline analysis (MNFO – Mini-fall-off) and to evaluate the formation properties (closure pressure, leak-off type and transmissibility), breakdown test was conducted with 2%KCl. Analysis is presented in Figure 2. Breakdown was observed at a surface pressure of 6256psi @ 3.5bpm.

Step Rate Test (SRT)&Step-Down Test (SDT)

SRT was conducted to estimate the extension rate and pressure, which was not observed in this case. It was also used to evaluate the near wellbore frictions which were estimated to be 700psi wherenumber of open perforations was only 7.

Calibration Injection (CI)

Calibration Injection treatment was performed post Breakdown. Treatment was pumped with crosslinked frac fluid to estimate the frac fluid efficiency. Results showed a very low fluid efficiency of only 5%.

Dynamic Closure Test

As it was discussed earlier, the MiniFRAC treatment could give erroneous results in formations with near-wellbore friction particularly in the absence of bottom-hole gauge. Therefore, Dynamic Closure Test was performed to estimate thetotal closure pressure after injecting the crosslinked fluid (DataFRAC). The total closure pressure value was slightly different compare to closure pressure estimated from MNFO. In this case, it was only managed to achieve a rate of 15.05bpm with a surface pressure limitation of 11,773psi. The possible closure was estimated to be 11,660psi with a gradient of 1.2psi/ft. It again indicated that the formation is highly stressed and the developed fracture was probably connected to a large natural fracture of mini fault. Pressure match based on our estimated closure pressure of 11,660psi for the DataFRAC treatment is shown in Figure 3.

Decision to Plug Lower PAB

After the execution of injection tests, nitrogen kick off job was performedto flow the well but no appreciable results were observed in-terms of production and wellhead pressure. Therefore this zone was plugged with the bridge plug.

Upper PAB formation

After setting the DST-2 and firing the TCP guns, modified Isochronal test was conducted on Upper PAB formation for 4 days. Maximum of 0.7MMSCFD production of gas was observed. Details are shown in Table 1.

Break Down Test

Similar to the Lower PAB, breakdown test was conducted and the pressure of 8,015psi was estimated by pumping a small volume (59.9bbl) of 2%KCl, later decline analysis was observed to evaluate the formation properties (closure pressure, leak-off type and transmissibility) which are shown in Figure 4.

Step Rate Test (SRT) &Step-Down Test (SDT)

After the conducting the SRT for Upper PAB, it was estimated that the extension pressure was very high i.e. 13,251psi at an extension rate of 5.1 bpm. The fracture couldn't hold the fluid; it was thus hypothesized that this tight reservoir has multiplelarge scale natural fractures or possible mini faults. Therefore, it became very necessary to move to dynamic closure test. SDT was conducted to evaluate the near wellbore frictions which were estimated to be 1,383psi and number of open perforations was only 4. Very high ISIP of 7,278psi with a fracture gradient of 1.186 psi/ft was estimated, which is another indicator that the formation was highly stressed.

Calibration Injection (CI)

After doing the breakdown, SRTand SDT, calibration injection treatment was performed. Here, the frac fluid efficiency was ~10%. Although a much better leadoff behaviour was observed but still it was on the lower side.

Dynamic Closure Test

In this case the dynamic closure test showed promising behaviour, it wasmanaged to achieve17.8bpm at the surface pressure of 11,341psi. Extension pressure of 12,400psi and closure pressure of 11,900psi (1.25psi/ft) was observed (Figure 5).

Pressure match for the DataFRAC treatment based on the closure pressure above is given in Figure 6.

Main Fracturing Treatment

Although, the closure pressurewas still high but looking at the pre-frac production results and margin of surface pressure limitations it was decided to conduct Main Fracturing treatment on this formation.

A redesign was made after taking into consideration the fact that the formation was highly stressed and has natural fractures. It was thus decided to pump a larger PAD stage with afluid loss agentin the PAD stages to compensate for the fluid efficiency; also, a 100-mesh slug was planned in between two PAD stages to increase fracture width and to erode the perforations (after observing the pressures).

The Main Treatment started at lower rates of 3.5 bpm to determine pumpability into the formation. Pressure trend was good as can be seen in Figure 7, therefore rate was kept on increasing till 18.5bpm. Since the pressure was very favorable, it was decided to stick with plan of pumping the 100-Mesh sand into the formation. As expected, 100-Mesh appeared to increase fracture width by eroding perforations.

As plan proceeded with success, a conventional approach of started pumping with low proppant concentrations and observing the pressure trends each time a proppant stage hit the formation, was adopted. Till 1.0 ppg of 20/40-ISP, the pressure trend continued to godownward, indicating the fracture was growing. Pressure leveled out when 1.5 ppg was on formation. Pressure trend was then monitored closely to avoid possible screen-out. Formation accepted 2 and 3 ppg, without issue. For 4.0 ppg, pressure trend started increasing when it was on formation, but the pressure increase rate was slow indicating that the formation was still accepting proppant, but was close to the end.

Since it was very close to the end and sand plug had to be pumped for the possible fracturing treatment on the upper formation, , it was decided to stick to a maximum concentration of 4 ppg. Overall the fracture job was pumped to completion without issueand thisoptimizeddesign helped control screen-out behavior that was seen on previous wells.

The well which was only producing 0.7MMSCFD before fracturing treatment started producing ~15times more i.e. 11MMSCFD, as can be seen in Figure 8.

Figures and Tables

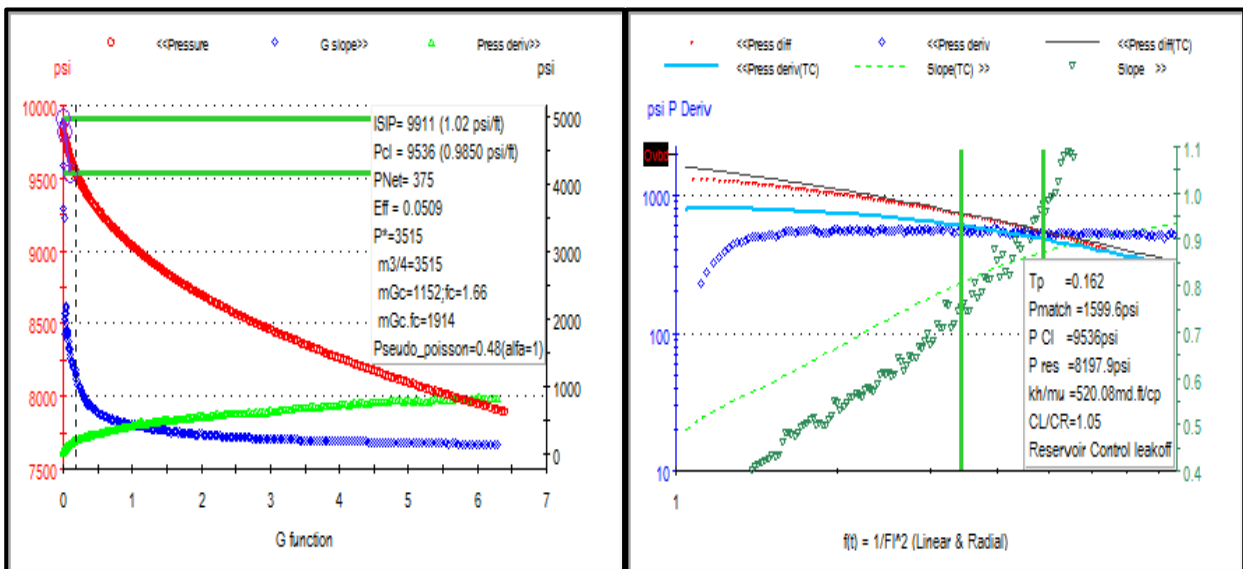Figure 1: Logging interpretation for Rizq-01
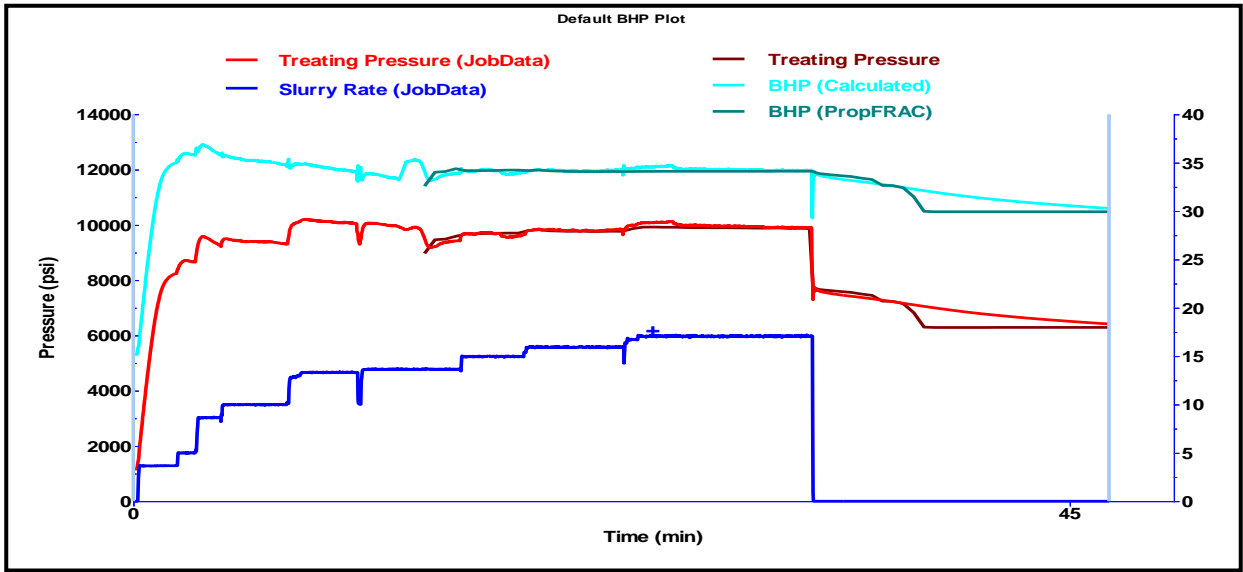

Figure 2: Lower PAB - Breakdown Test Analysis

Figure 3: Lower PAB - DataFRAC Pressure Match

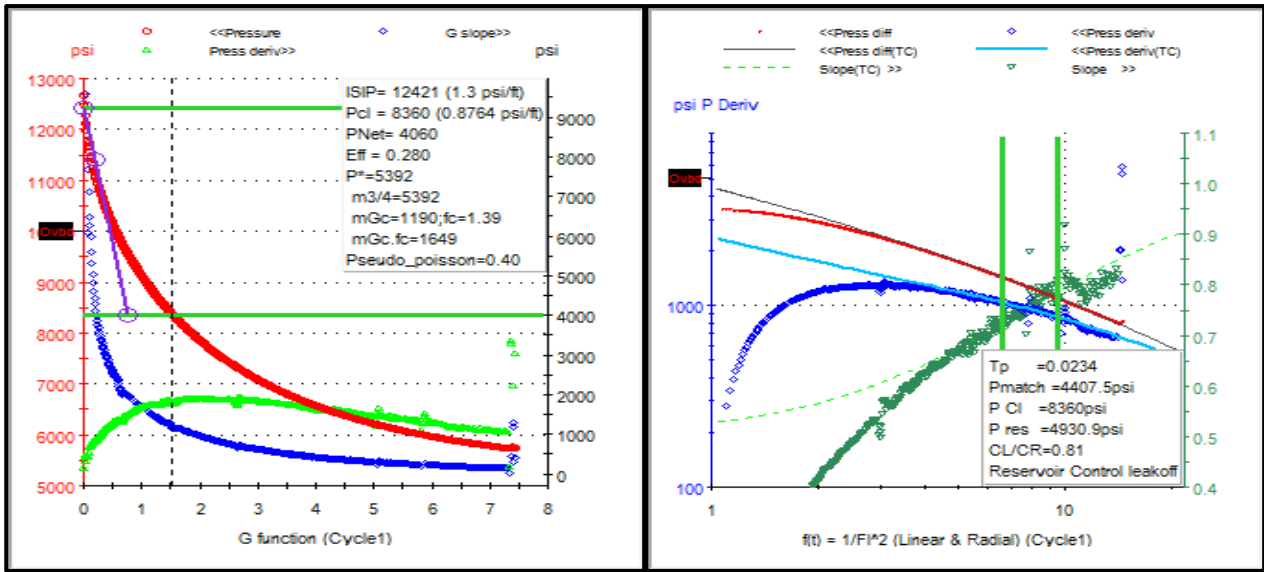|		DST # 2A TESTING RESULTS		
		WELL # RIZQ – 1		
		Formation = Upper Pab		
Test Intervals		2,900.0 - 2,904.0 = 04 m 2912.0 - 2,915.0 = 03 m		Total 07 M
		Production Data During Modified Isochronal test		
		FIX CHOKES		
Date	11/4/2015	12/4/2015	12/4/2015	13/4/2015
Choke Size	16/64"	20/64"	24/64"	28/64" (EF)
Flow Time (Hrs)	4	4	4	12
WHFP (Psi)	452	290	217	184
WHFT (°F)	85	87	90	91
Separator Sep. (Psi)	61	66	63	68
Separator Temp. (°F)	72	80	88	88
Qcond. (BPD)	NIL	NIL	NIL	NIL
QGas (MMSCFD)	0.585	0.618	0.652	0.709
QWater (BPD)	NIL	NIL	NIL	NIL

Table 1: Modified Isochronal Test

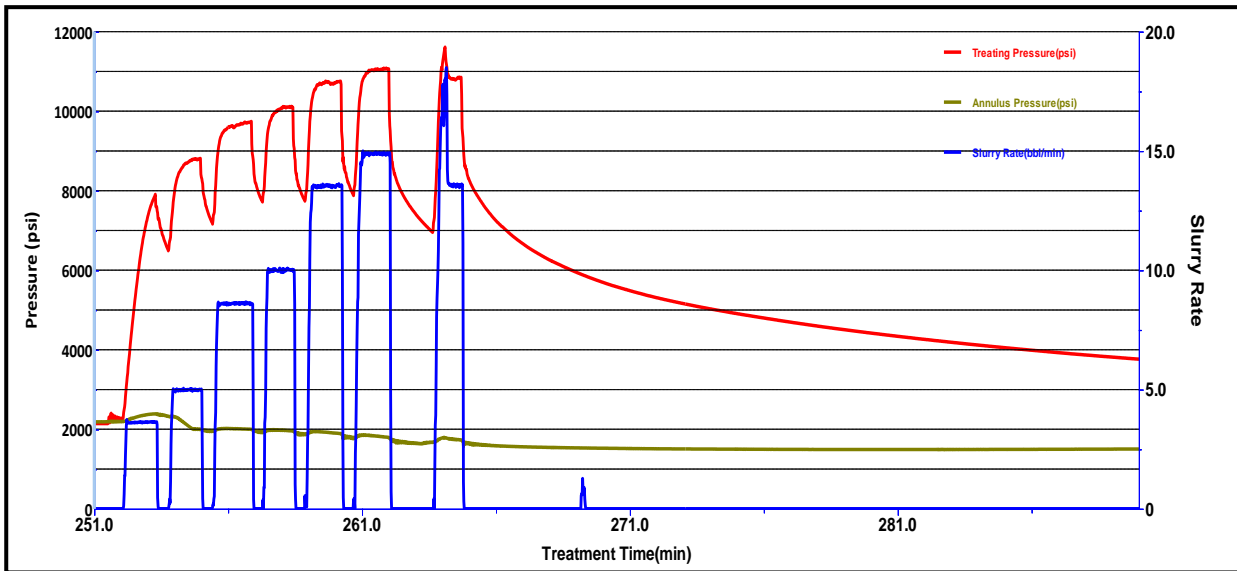**Figure 4: Upper PAB - Breakdown Test**

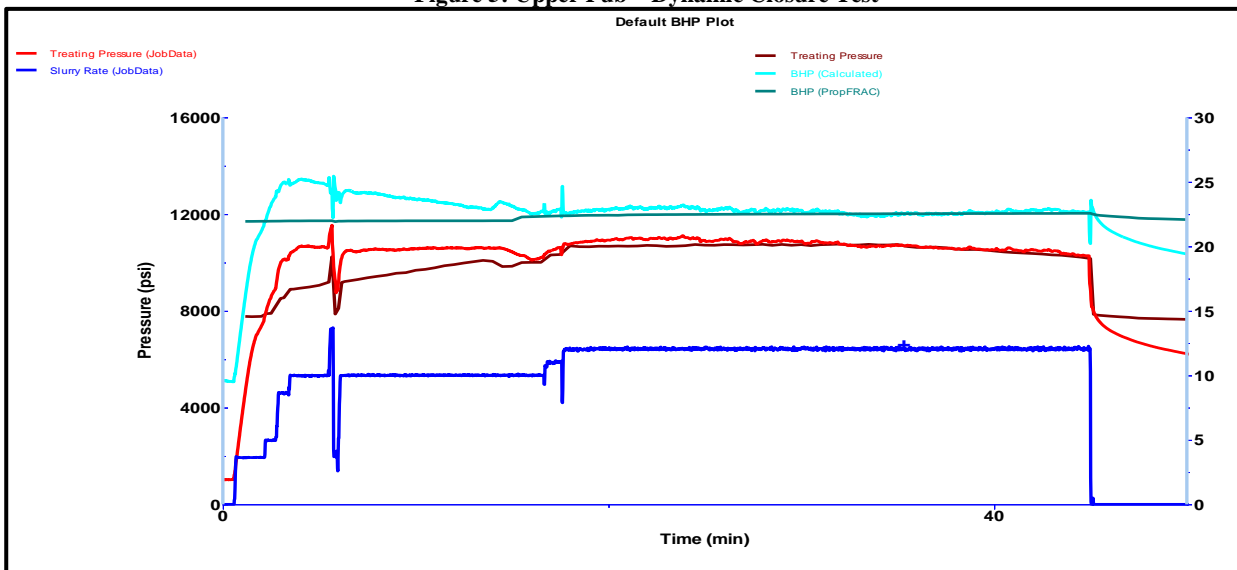
Figure 5: Upper Pub – Dynamic Closure Test

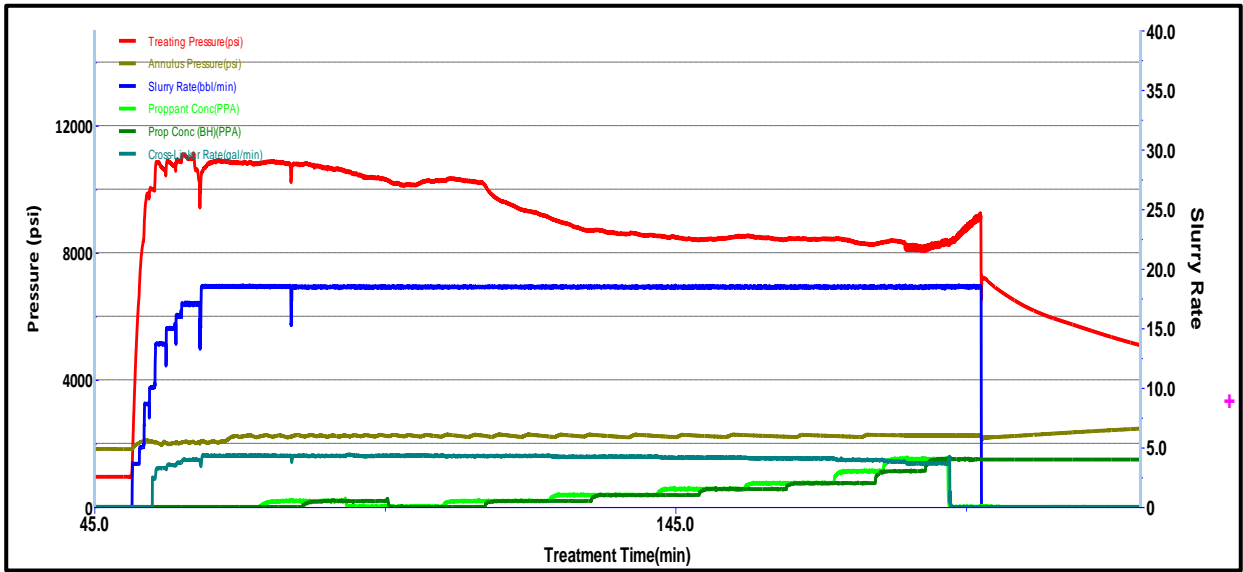**Figure 6: Upper PAB - DataFRAC Pressure Match**
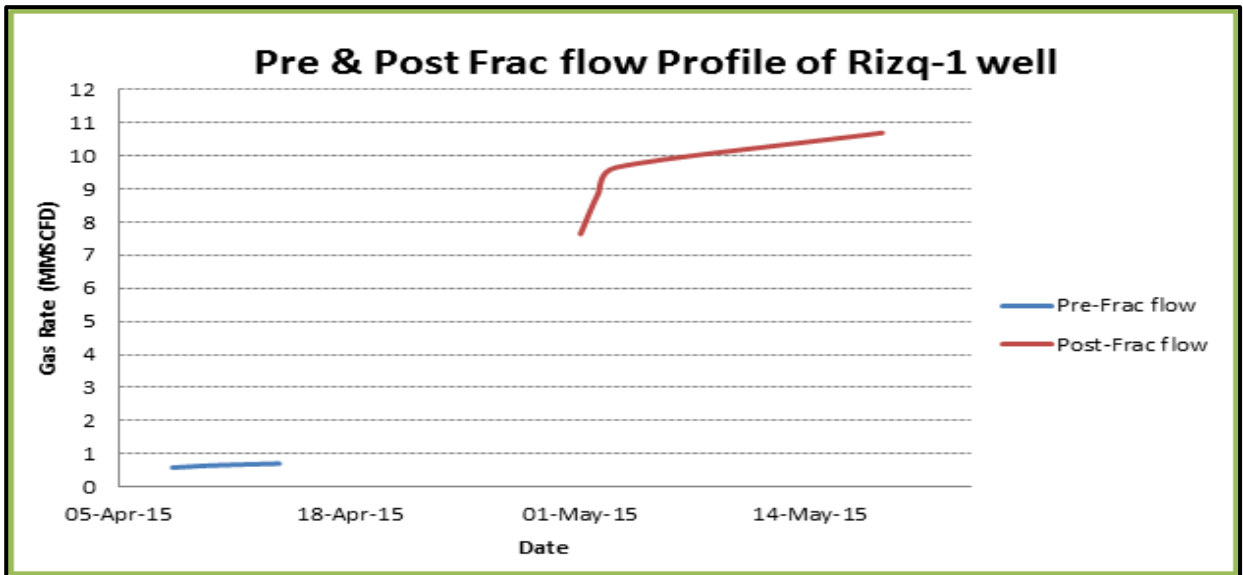
Figure 7: Upper PAB - MainFRAC

Figure 8 : Pre & Post Frac Production for Rizq-01

CONCLUSIONS

Proper execution and analysis of the DataFRAC treatment and accordingly updating the design, as per the study discussed in introduction section, was very helpful in controlling the fracgeometry.As a result of such modification, a significant increase in production was observed. However, there are recommendationsthat could be further usefulfor the future wells in similar formations:

- Size correction of acoustic log should be conducted.
- Real time bottomhole gauges should be used.
- Limited entry perforations can be used to create dominating fractures.
- Using degradable fluid loss additive in the PAD stages can be very useful for this type of formations and can help reduce the damage further.

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