Volver

# Why are Conventional Perforating Systems Deployed on Unconventional Reservoirs?

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## Abstract

Many aspects of completions and stimulation treatments for unconventional reservoirs have benefitted from the development and optimization of new technologies. However, perforating gun systems have remained largely unchanged. Perforating systems historically used in conventional reservoirs are the same for plug and perf completions within unconventional plays. These systems create long, spiral-pattern perforations that were originally designed to provide effective omnidirectional drainage pattern along the entire perforated length. Is this optimal for unconventional wells and should we continue to use them?

To create hydraulic fractures perpendicular to the wellbore axis, the orientation of horizontal wells is typically parallel to the least principal stress in unconventional reservoirs. This geometry limits the contact area between the primary hydraulic fracture and the wellbore. Yet, in order for traditional perforating systems to provide sufficient inflow geometry for stimulation, they must create multiple entry points along the axis of the wellbore. This may cause initiation of several competing hydraulic fractures instead of one dominate fracture. Multiple fractures in the near wellbore region ('fracture tortuosity') may cause the development of a choke that limits the ability to perform the treatment. Furthermore, the perforations are typically not oriented despite the direction of the perforation playing a key role in the pressure required to initiate the hydraulic fracture. In short, a current multiple entry system extended along the axis of the wellbore reduces the efficiency of the treatment. It therefor makes sense to design a perforating system that would mitigate these factors and increase the reliability of hydraulic fracturing treatments in unconventional reservoirs.

An optimized unconventional perforating system should axially consolidate the link between the well and the hydraulic fracture and orient the perforations with the aim of reducing the variability and magnitude of the fracture initiation pressure. This paper presents a novel and proven perforating system that features only three orthogonally oriented shaped charges.

Field trial results presented here reveal positive indications concerning breakdown pressures, near wellbore friction, and treatment pressures. More importantly, this design exhibited faster and more stable injection rates at reduced treatment pressures. This paper will compare the fracture treatment performance on stages perforated using conventional systems against those stages perforated with the new system. It will also discuss the system qualification and operational planning, and discuss the merits of new perforating designs for unconventional stimulations.

## Introduction

As the industry looks forward to completing complex multi-stage horizontal unconventional wells with increasing focus on operational efficiency, perforation methodologies (Behrmann and Nolte 1998) are gaining much attention since they influence the critical processes of relevant stimulation treatments and the overall well productivity. In particular, several studies have shown the importance of perforating for hydraulic fracturing and demonstrated that perforating for hydraulic fracturing is not the same as perforating for production (Behrmann and Nolte 1998, Underwood et al. 1996, Pongratz et al. 2007). Perforation design therefore has a significant impact on fracturing efficiency and production performance.

In recent years, it has been generally acknowledged that while conventional, spiral-clustered or zero degree phase perforating systems enable effective hydraulic fracturing in vertical wells, using this conventional design in unconventional horizontal wells lead to fracturing inefficiencies. In horizontal wells, where the wellbore is perpendicular to the least principal stress plane, conventional perforating systems create long, spiral-patterned or linear perforations along the well trajectory that often lead to flow inefficiencies thereby leaving formation under stimulated or even untreated because fluid and proppant are not effectively directed. Moreover, these conventional perforations can lead to near wellbore tortuosity and also create a network of competing fractures near the wellbore that can all lead to reduced fracture lengths/widths, screen-outs and impair overall communication with the reservoir. Hence, if we reduce the energy restricted by these effects, we can maximize the energy directed to the fracture system.

Recent works (Daneshy 2009, 2014, LeCampion et al. 2015) have clearly emphasized the above issues and have also highlighted the immediate need for a customized perforating system that can truly engineer a multi-stage horizontal well completion. In this context, the design criteria that may be worth noting are listed below:

- Alignment of all perforations in each cluster in a single plane perpendicular to the borehole axis to create a unified fracture plane (Daneshy 2009). In fact, recent work of Albert et al. 2016 presented a system that utilizes standard guns with angled shaped charges to create a focused fracture plane. Similar alternate system was also discussed by Barker et al. 2007. However, it is important to note that formation in homogeneities (bedding planes, natural anomalies in the rock), water gap, stand-offs and clearances, uncertainties in shaped charge performance can all affect the performance of angled shaped charges and may not lead to a single-fracture plane.
- Uniform partitioning and distribution of fluid through engineered staging, spacing and limited entry.
- Shortest possible gun system in order to optimize fracture treatments. The longer the guns are, the higher the possibility of wellbore tortuosity and multiple initiation fractures that can compete with each other.
- The higher the number of holes in a cluster, the harder it is to manage friction pressure and design a fracture treatment.
- Is there a possibility to use different shaped charges (mix of big-hole, good-hole or deep penetrating charges) to maximize flow area/penetration, optimize perforation friction and enhance proppant distribution?

Motivated by the above, we were set with a goal on developing a novel perforating system that is aimed towards providing a solution for perforating unconventional reservoirs. We have successfully leveraged our expertise in shaped charge and gun systems development along with a comprehensive evaluation of pressure pumping strategies and unconventional well completion challenges. In this paper, the design philosophy is presented first, followed by a discussion on system development and qualification. Subsequently, the paper also talks about a successful field-trial conducted recently in the Utica Shale to realize and highlight the benefits of the system.

## Design Philosophy

The objective was to develop a novel frac-optimized system that optimizes fracture treatment and improves reservoir access in unconventional wells. The development of the system involved a comprehensive evaluation of technical/operational aspects that encompassed the integrated areas of perforating, unconventional completions and pressure pumping. Critical design factors related to mitigation of tortuosity (competing fractures), maximizing perforation flow area, achieving a unified fracture plane for effective proppant treatments etc. were thoroughly evaluated to develop the concept of this system (see Fig.1). Consequently, the system design was developed based on the following driving factors:

- Number of perforations
- Maximize and axially consolidate the flow area.
- Orienting the flow entry to the high side of the lateral
- Compact and efficient design
- Improved reliability
- Reduced impact on health, safety and environment.

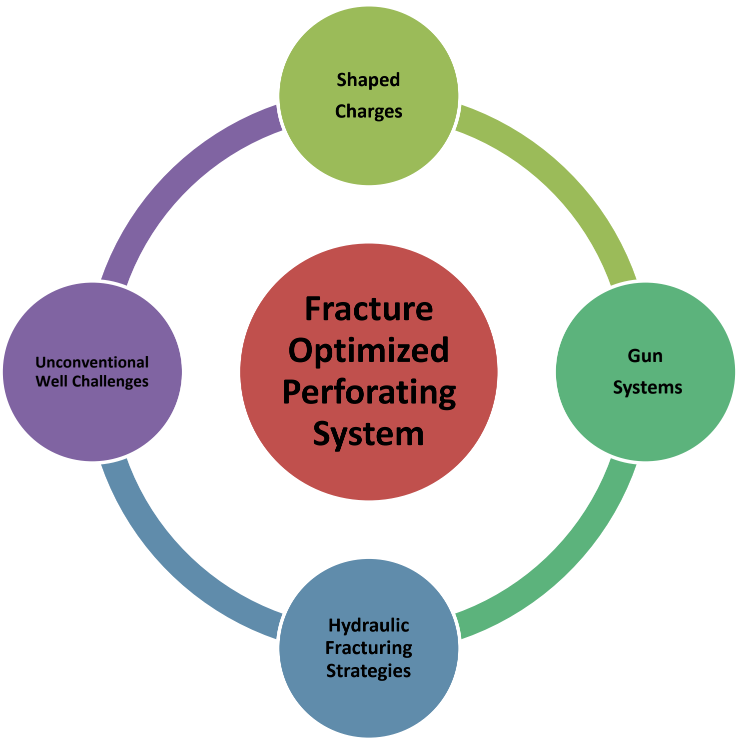


Fig. 1. Key elements of a fracture optimized perforating system

**System Development & Validation**

The frac-optimized system used only three shaped charges to achieve an optimized perforation pattern. The shaped charges are orthogonal to each other. Two big-hole charges on the sides and a deep penetrating charge on the high side (**Fig.2**) provide an optimal area-to-penetration ratio, and satisfy typical requirements relating to friction pressure and pumping rates. The design consideration for the deep penetrating charge oriented parallel to the maximum principal stress serves to reduce breakdown pressures. The presence of a wellbore at depth magnifies the in-situ stresses around, and in close proximity to the wellbore. The increased compressive stresses - often referred to as hoop stresses - are of primary importance for this work. The magnitude of the hoop stress is not necessarily equal, and is largely a function of the difference between principal stresses acting orthogonally to the wellbore axis. Given anisotropic stress conditions, the resultant hoop stress is at a minimum in the direction parallel to the maximum principal stress. For horizontal wells, in normal faulting stress regimes, this direction is vertical. The design utilizes a depth of the charge selected to reach as deep as possible, in order to mitigate the impact of hoop stresses on fracture initiation, while maintaining a reasonable perforation diameter for sufficient flow during early fracture development. Once the fracture develops the large diameter perforation charges - set at -90 and 90 degrees from the top, deep-penetrating charge-dominate the flow path for proppant slurry to enter the fracture.

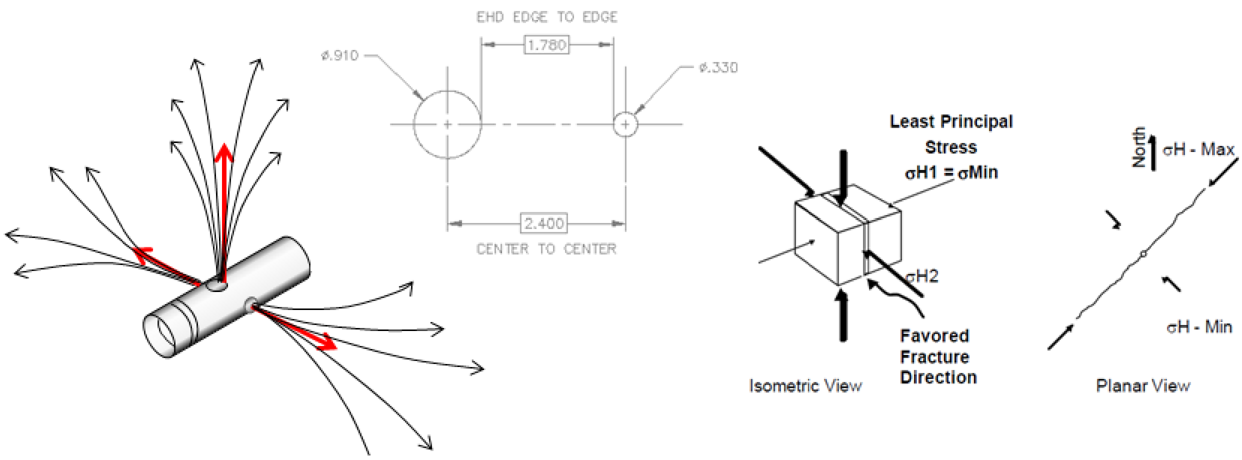


**Fig. 2. Details of the frac-optimized system**

Unlike the limitations mentioned by Albert et al. 2016, we were able to axially consolidate the shaped charges (edge-to-edge spacing being only 1.78 in) to achieve a unified fracture plane. The total flow area achieved with this system was 1.69 in$^2$, which is higher than that achieved with conventional gun systems (e.g. a standard 2 ft, 6SPF with a standard charge would provide 0.8 in$^2$ . Note that by axially consolidating the shaped charges and careful engineering of other gun hardware components, a compact gun measuring only 18 in. in length was developed, thereby ensuring easier handling and improved operational efficiency.

As part of system qualification, testing was conducted to quantify shaped charge performance. Multiple tests were shot decentralized in a 5-1/2” 20# P110 casing using both big-hole and deep penetrating charges. The charges were setup in our engineering laboratory using the appropriate internal standoff, water gap and casing as shown in table below. The **Table 1** and **Figure 3** also show entry hole diameter and total target penetration measured from the casing plate and concrete targets. The big-hole charge provided an average entry hole diameter (EHD) of 0.91” with an average penetration (TTP) of 5.13”. The deep penetrator charge provided an average hole diameter of 0.33” with an average penetration of 22.0”. Subsequently, survival tests (**Figure 4**) were also conducted on the full- scale system, whereby the gun had a maximum of 2.78% swell after shooting which correlates to a maximum diameter of 3.470” in a typical 3-3/8” gun system. Further, the system was thoroughly inspected to ensure there were no cracks or splitting of the system.

<table>
<tr><th>Shot #</th><th>Charge type</th><th>Internal standoff (in.)</th><th>Water Gap (in.)</th><th>Average TTP (in.)</th><th>Average EHD (in.)</th></tr>
<tr><td>**1A**</td><td>BH</td><td>0.570</td><td>0.804</td><td rowspan="2">5.13</td><td rowspan="2">0.91</td></tr>
<tr><td>**1B**</td><td>BH</td><td>0.570</td><td>0.804</td></tr>
<tr><td>**2A**</td><td>DP</td><td>0.360</td><td>1.608</td><td rowspan="2">22.0</td><td rowspan="2">0.33</td></tr>
<tr><td>**2B**</td><td>DP</td><td>0.360</td><td>1.608</td></tr>
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**Table 1. Shaped charge qualification testing**


**Fig. 3. Entry hole diameter visualization for the big-hole (top) and deep penetrating (bottom) charges**

| | Body Swell (in) | Dia Swell % |
|---|---|---|
| Gun 1 | 3.470 | 2.777% |
| | 3.460 | 2.481% |
| | 3.460 | 2.481% |
| Gun 2 | 3.450 | 2.184% |
| | 3.470 | 2.777% |
| | 3.470 | 2.777% |
| Ave | 3.463 | 2.579% |
| Max | 3.470 | 2.777% |
| Min | 3.450 | 2.184% |

| | Before (in) |
|---|---|
| OD | 3.380 |
| | 3.380 |
| | 3.380 |
| | 3.370 |
| | 3.370 |
| | 3.380 |
| | 3.380 |
| | 3.370 |
| Ave | 3.376 |

**Fig. 4. Measured data obtained from "gun swell" tests**

## Field Trial Results

The frac-optimized system was recently tested in a multi-stage horizontal well in the Utica shale, Ohio. The operator elected to run the frac-optimized system in two stages of the multi-stage completion, in the mid-section of the well. The plan was to acquire data during fracture treatment operations and compare the performance of the system with conventional perforating stages in the same well. The standard design called for five clusters per stage, with a hybrid treatment schedule at a target stage rate of 95 BPM. The only changes to the treatment were the perforation design; all other stage design parameters were constant. The stage and cluster spacing, treatment volumes and mass and pumping schedule were the same for all stages, regardless of the perforation geometry. The conventional stages were perforated with standard charges (0.4 in. hole diameter) with 8 holes per cluster (40 total perforations per stage) at 60 degree phasing. The frac-optimized stages consisted of perforation clusters with the three orthogonally oriented charges described in the preceding section.

The treatment data (injection rates, pressures, and proppant concentrations) was analyzed in detail for different sequences during each stage of the treatment (breakdown, pad, proppant and flush stages). **Table 2** lists quantitative comparisons of the data, which we describe further in this section. We thoroughly analyzed each stage, however in the interest of making a fair comparison, the analysis presented here focused on a subset of stages in close proximity to the frac-optimized stages (13 stages run with conventional guns in close proximity to two stages run with frac-optimized system). **Figure 5** shows an example of the surface treating pressures and the slurry rates for one frac-optimized stage and an adjacent conventional stage. We have selected one representative component of analysis for each sequence in the treatment (breakdown, pad, proppant and flush) to illustrate the effectiveness of the frac-optimized system. For simplicity, this section focuses on surface treating pressures.

Comparing the magnitude of breakdown may be insufficient for quantification of performance, especially if injection rate or fluid system viscosity varies during breakdown. **Figure 6** compares the magnitude of surface treating pressure and injection rate during breakdown. Though not the absolute lowest in magnitude, breakdown pressures of the frac-optimized stages were on average 4% lower than the conventional perforation stages. The injection rate during breakdown was on average 10% higher. Therefore, our analysis shows a positive & measureable impact on the reduction of breakdown pressures with the frac-optimized system. The volume of fluid for the pad was consistent for each stage. However, each stage started proppant prior to reaching full designed rate (**Fig. 6**). Consequently, the impact of proppant on erosion of perforations and near wellbore tortuosity presents difficulty in directly comparing treating pressures during the pad sequence of the treatments. Nevertheless, during the pad, the frac-optimized stages exhibited a 4% decrease in maximum surface treating pressure and an 8% increase in maximum injection rate compared to the conventional perforated stages.

In addition to comparing only the clean fluid sequence, the analysis was also extended to encompass the time required to reach full injection rate. The rational was based on the observation that injection rates were controlled real-time and rates were increased only as surface treating pressures allowed (see **fig. 5** for example of treating data). Accordingly, the time required to reach full rate represents how efficient the perforation design is at mitigating problems with the near wellbore friction pressures. The time required to reach designed injection rate was 12 minutes for frac-optimized stages, while standard perforations required, on average, 16.4 minutes to reach designed injection rate. This represents a 35% decrease in time required to reach designed injection rate, for the frac-optimized stages. To quantify the fluctuations in injection rate required to maintain safe surface treating pressures, we calculated the standard deviation in the treatment injection rate, after achieving full designed rate. As illustrated in **fig. 7**, frac-optimized stages exhibited some of the quickest times to full rate, while exhibiting an 82% decrease in the standard deviation of injection rates. A few of the standard perforation stages exhibited quicker times to full rate, however they subsequently required more fluctuations in rate (higher standard deviations) to maintain safe surface treating pressures. The results of this analysis suggests the frac-optimized stages exhibited an optimized balance between consistent and stable injection rates during the treatment and reduced times to achieve designed injection rate.

**Table 2. Frac-optimized Vs Conventional Perforating Data Analysis**

| | | | **Avg. Frac-Optimized** | **Avg. Conventional** | **% DIFF** |
|---|---|---|---|---|---|
| Breakdown | STP | (psi) | 9180 | 9498 | -3.5% |
| | Slurry rate | (BPM) | 56.5 | 50.6 | 10.3% |
| Pad | STP max | (psi) | 9482 | 9832 | -3.7% |
| Pad & Initial Proppant Stage | Time to Full Rate | (min) | 12.2 | 16.4 | -35.1% |
| Proppant Stages | Total avg. mass rate | (lb/min) | 5386 | 5135 | 4.7% |
| | Avg. slurry rate | (BPM) | 94.0 | 90.0 | 4.3% |
| | STD dev. slurry rate | (BPM) | 2.04 | 3.72 | -82.3% |

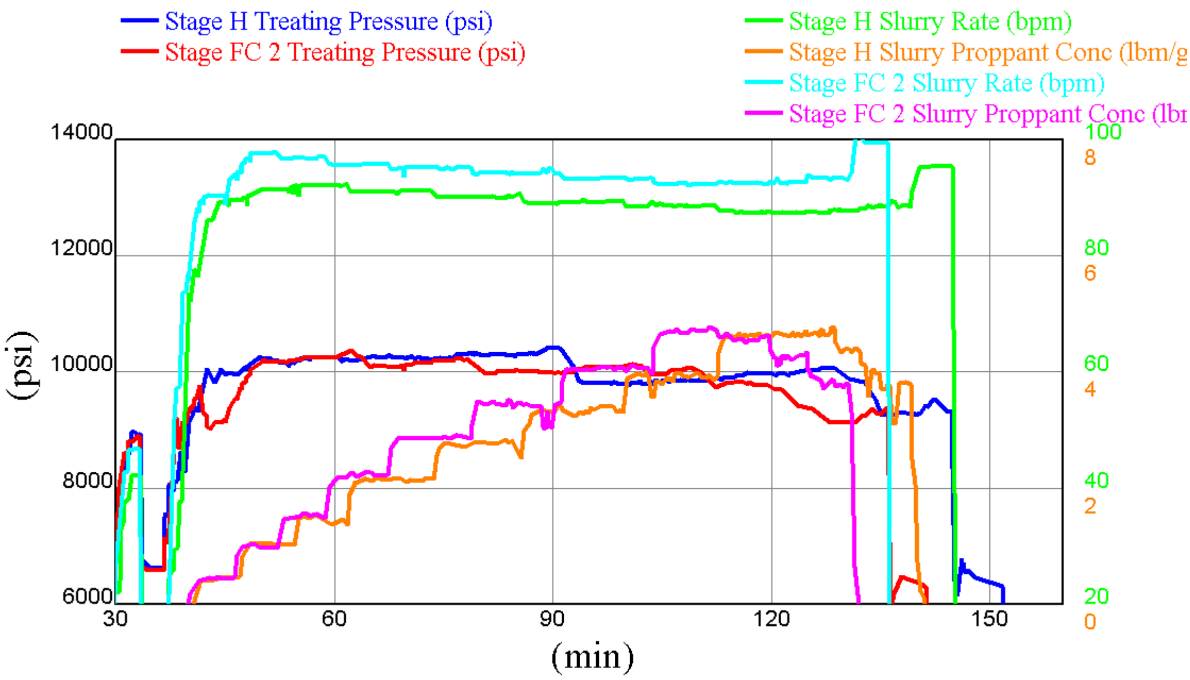



**Fig. 5. Stage pumping data: FC 2 is a stage completed with frac-optimized system**

**Stage H is the previous stage completed with conventional perforating system**

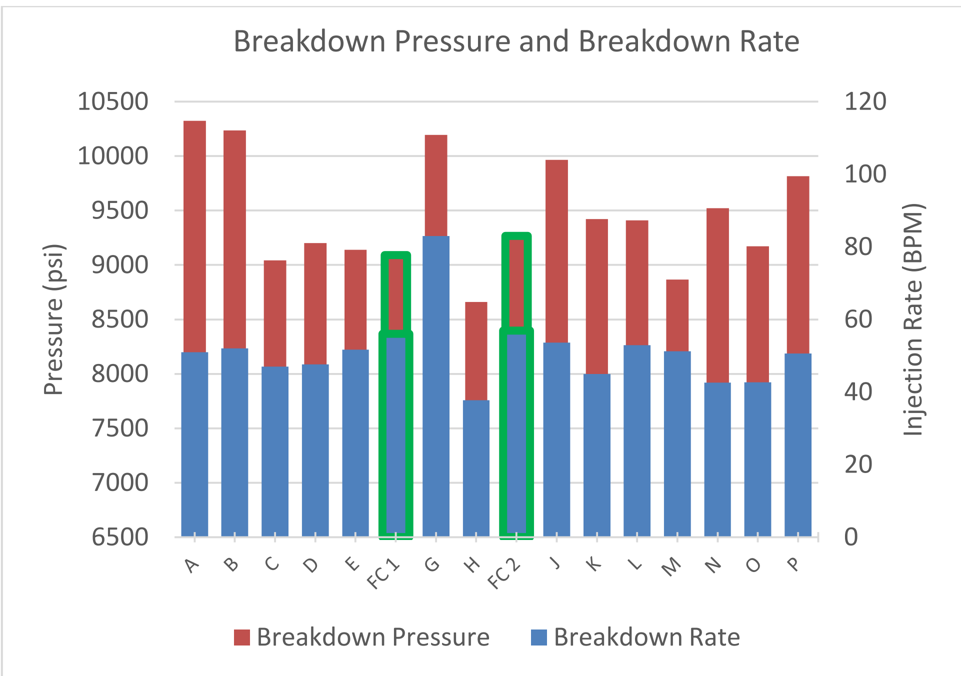



**Fig. 6. Plot of Breakdown Pressure and Rate**

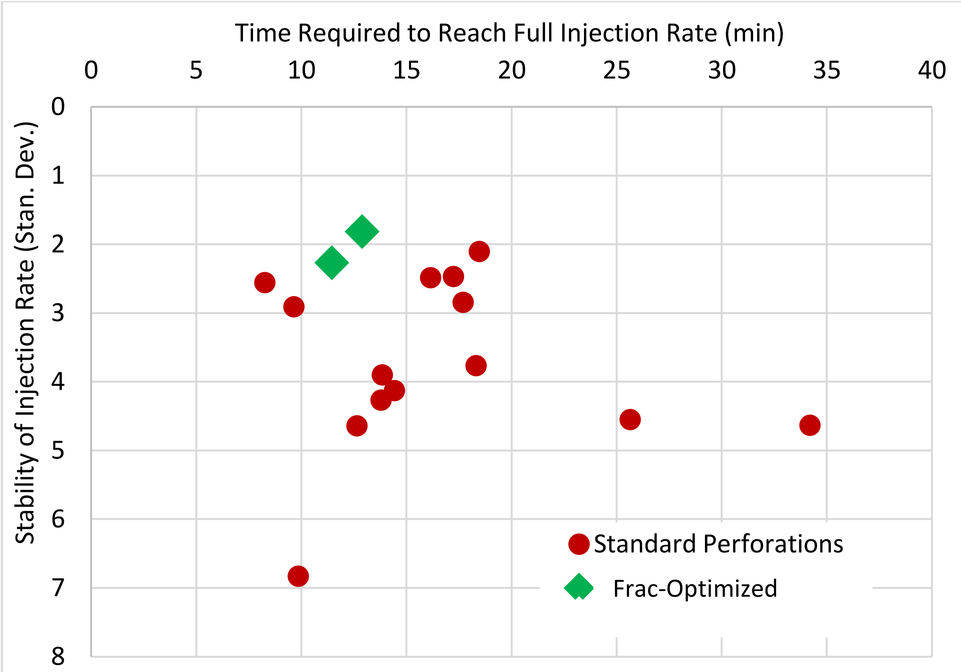



**Fig. 7. Time required to reach full injection rate vs. standard deviation of injection rate**

**Figure 8** compares pumping performance during only the proppant stages. Frac-optimized stages had some of the highest average injection rates during the proppant stages, and proppant mass rate, still they still exhibited the highest stability in injection rates. The data show the frac-optimized stages exhibited 5% higher average injection rate during proppant with an 82% reduction of standard deviation of injection rate. This indicates that near wellbore friction pressures were reduced with the frac-optimized system allowing for more aggressive treatment rates at moderate surface treating pressures.

To evaluate the differences between near wellbore friction pressures, we calculated the difference between bottom hole instantaneous shut in and final treating pressures during the flush stage. A more sophisticated analysis necessarily requires some form of diagnostic (such as step down tests). Yet this simple calculation provides a qualitative gauge of system performance. Estimates of near wellbore friction pressures at the end of the job exhibited a 32 % decrease for the system relative to standard perforations.

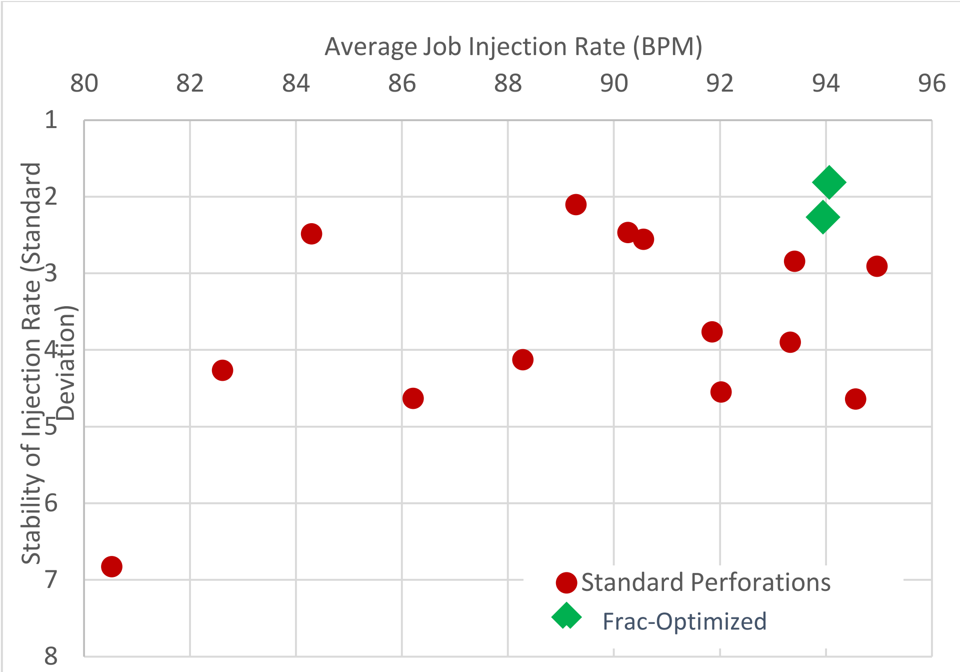


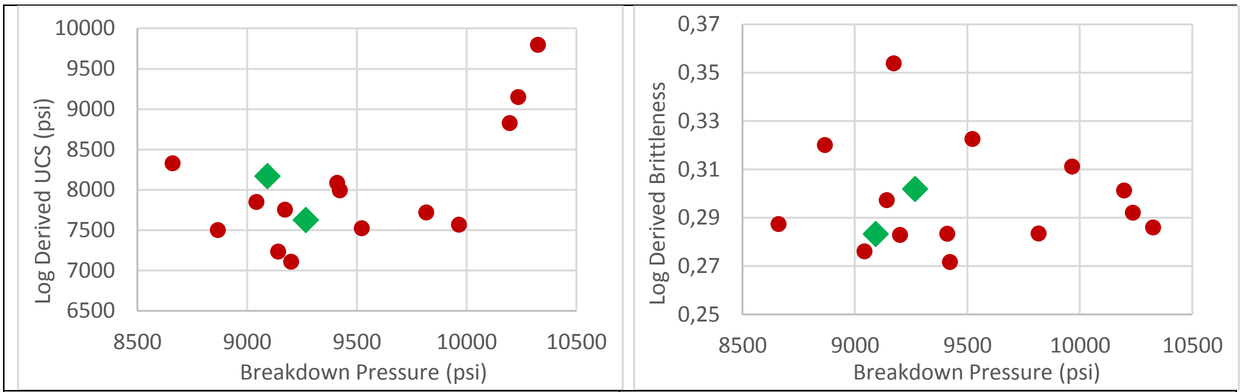

**Fig. 8. Average injection rate vs. stability of injection rate during proppant stages**

To evaluate the results of treatment performance analysis above on changes in lithology or rock mechanical properties we evaluated the various log analysis outputs at each stage with the analysis highlighted above. An advanced dipole sonic log provided a characterization of the lateral, which delivered a full suite of rock mechanics and reservoir properties (e.g., stress, stiffness, brittleness). While a full description of this analysis is beyond the scope of this work, two illustrative examples are in **Figure 9**.

**Figure 9 (a)** contains a plot of breakdown pressure vs UCS (evaluated at each individual perforation cluster). The expectation is that the UCS may provide at least a qualitative representation of rock tensile strength. Therefore, lower UCS may exhibit lower breakdown pressures. Yet, we found no correlation between UCS and the magnitude of breakdown pressure. Similarly, **Figure 9 (b)** compares breakdown pressure to rock brittleness, again with no correlation. We compared the full suite of properties yet we found no correlation between the log-derived properties and various treatment outcomes (e.g., treating pressures, average injection rates, etc.). That is to say, the results of our analysis appear to be a result from the change in the perforation geometry and not changes in geology or geomechanics properties along the lateral.

In general, the key benefits of the frac-optimized system are listed below:

- During breakdown stage, frac-optimized exhibited a 300 psi reduction in breakdown pressure even at a 10% increase of injection rate.
- 35% decrease in time required to reach full, as designed, injection rate.
- Increase in proppant mass rate of 250 lb/min.
- 4 BPM increase in average slurry rate during proppant stages
- 82% decrease in standard deviation of injection rate during proppant stages, indicating an increase in rate stability.
- 32 % decrease in near wellbore friction pressure




(a) (b)

**Fig. 9. (a) UCS vs breakdown (b) brittleness vs breakdown**

## Conclusions

Because the frac-optimized system aims toward reducing competing fractures and tortuosity near the wellbore, fracture length and propagation were optimized during treatment, leading to average treatment pressures that were 4% lower than those recorded with the standard perforating system. By focusing treatment pressures through just three axially consolidated perforations per gun, frac-optimized delivered treatments in efficient fracture planes; thereby decreasing the time it took to reach the target pump rate per stage (95 BPM) by 35%. Also, a significant reduction in near wellbore friction pressure enabled higher and more stable slurry injection rates, improving connectivity. These observations do not appear correlated to any log derived rock mechanics parameter; that is to say, these results do not appear to be lithology dependent. The system not only optimized fracture treatments, but it also improved operational efficiency and reliability with a shorter gun size that is easier to handle. Reducing the number of charges also decreased HSE risk during transit and on the rig floor.

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