Efficiency during 2020’s downturn:
Strategies for reducing the delivery cost to place a pound of proppant downhole

THE SHALE INDUSTRY CHANGED BEYOND RECOGNITION OVER THE LAST DECADE, and it is once again in rapid transition. While we are unsure about the nature of innovations to make U.S. shale ever more competitive, we are certain that the current downturn will drive a further reduction in $/BO — the total cost to lift a barrel of U.S. shale oil to the surface.

The last decade saw a tenfold rise in horsepower, a twentyfold surge in yearly stages pumped and a fortyfold yearly proppant mass increase. U.S. oil and gas employees grew their per capita production twofold, and U.S. pumping services employees increased their proppant throughput by a factor of 8 over the last eight years.

As a result, the all-in price charged by service companies to place a pound of proppant downhole decreased from about $0.50/pound in 2012 to about $0.10/pound today. In this article we discuss a few suggestions that may drive a further reduction.

“There’s a fine line between a numerator and a denominator.”
— YOGI BERRA

As directed by Yogi Berra, the shale industry has worked both sides of the $/BO or $/BOE ratio. Efficiency gains and technology have helped to dramatically reduce drilling and completion costs for shale wells in the numerator. Frac design evolution, mostly to create larger and higher-density fracture networks, have helped to boost well production in the denominator.

As shown in the graphs at right, well cost in several liquids-rich basins dropped from about $7.3 million to $5.1 million between 2012 and 2019. Well production, over that same period, on a 365-day production metric, increased from 69,000 to 134,000 BO. The combined benefit of this 30% reduction in cost and 94% improvement in production represents a 63% $/BO discount over just seven years.

The technology focus in fracture treatments in current U.S. shale plays
has been on creating ever-larger and ever-denser frac fairways through gradual completion changes — much like the original goals for Barnett Shale fracs at the dawn of the shale revolution.

Larger fracture networks can be achieved by going horizontal, drilling longer laterals and increasing proppant mass and fluid volume. Denser fracture distribution has come through higher stage count and an increase in stage intensity, higher pump rate and changes in perforation strategy toward extreme limited entry with fewer perforations and more clusters/fracture initiation locations per stage for better overall fracture distribution.

**DOING MORE WITH LESS**

While some of our previous papers have focused on pushing the envelope on completion design parameters (SPE paper 199345), in this article we focus on proppant delivery cost — the cost to place a pound of proppant in a fracture downhole, where it can contribute to a well’s production for years to come.

The graphs at right illustrate how the industry has been changing to address proppant delivery, constantly striving to find better chemical products and pump fewer of them. The graphs include FracFocus data on a variety of placement and production chemicals for about 100,000 wells in U.S. liquids-rich basins, including the Williston, Powder River, DJ, Permian basins, as well as SCOOP/STACK and Eagle Ford. All chemicals have been averaged on a per-well basis into a gallon-per-thousand gallons (gpt) metric.

First, there is a general trend away from more expensive chemical derivative guar systems to simpler low-concentration guar systems, as well as a simplification toward FR fluid systems. This manifests itself as a gradual decrease, from about 3.5 to 1.5 gpt (14 to 6 ppt for dry guar), for the average gel concentration. At the same time, the overall per-well concentration of friction reducers has been increasing since 2014, due to the fact that larger portions of each job are pumped with FR at the expense of gel, and that in some of these replacement jobs, in order to achieve some viscosity, FR concentrations have been boosted.

Second, both the proppant delivery chemicals and the formation treatment chemicals that are part of the fracture treatment have become more effective, lower in number of products and smaller in quantity. For example, elimination of gel from jobs eliminates the need of a crosslinker and possibly a breaker — although some operators require a breaker in HVFR jobs. That leaves the potential need, depending on rock requirements, for surfactant, scale control, clay control and biocide.

Our approach is to measure the individual and combined performance of these chemicals and the impact they have on physical rock and fluid parameters with a growing range of expensive lab and field testing toys, and to compare the potential impact of these choices in our extensive production database.

As our industry trades viscosity for velocity in jobs that are adding a 3-5 bpm rate yearly, and overall viscosity needs on jobs have been lowered by a gradual change to smaller-mesh proppants, we may be able to get away with a lower viscosity than what was needed yesteryear. Defining viscosity in terms of a fluid’s elastic properties (what drives proppant transport) translates to targeting more meaningful viscosities in the field. Also, we need to review trade-offs between a cost-effective product, of which we require more product usage to build a specific viscosity, versus a more expensive high-end product that could require less product. Ultimately, the choice between these products is driven by the cost to generate the same amount of proppant carrying capacity.

In addition, lab testing may allow justification for use of an expensive additive if it proves effective in production enhancement. Alternatively, it may show that a more cost-effective solution
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<tr>
<th>Avg Biocide Concentration (gpt)</th>
<th>Avg Breaker Concentration (gpt)</th>
<th>Avg Clay Control Concentration</th>
<th>Avg Crosslinker Concentration</th>
<th>Avg Scale Concentration</th>
<th>Avg Surfactant Concentration (gpt)</th>
<th>Avg Gel Concentration (gpt)</th>
<th>Avg FR Concentration (gpt)</th>
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**Diagram:**

- Avg FR Concentration (gpt)
- Avg Gel Concentration (gpt)
- Avg Biocide Concentration (gpt)
- Avg Breaker Concentration (gpt)
- Avg Clay Control Concentration
- Avg Crosslinker Concentration
- Avg Scale Concentration
- Avg Surfactant Concentration (gpt)
maintains similar production to a higher-end product. These choices all help to drive $/BO down through a real-data focus.

CONSIDERATIONS FOR FLUID SYSTEM CHANGES

As described by Ben Poppel’s SPE paper 199760 titled “Fighting the Fear: Overcoming Preconceived Notions of Low Polymer Cross-linked Gels and High Viscosity Polyacrylamides in Unconventional Fracturing,” lab and field data interpretation shows new fluid systems are as successful as traditional systems to effectively place proppant downhole. They may require a learning curve — brief in today’s high stage count world — but screenouts are generally no issue once a frac crew and on-location consultant become familiar with the new system. As our customers become more familiar with these new systems, overall gel or FR concentrations can be cut significantly without impacting proppant placement success, making the new systems very competitive on the metric of cost per pound of proppant placed.

Please note for the table above, input costs can vary dramatically from basin to basin. Therefore, we recommend a detailed financial analysis of all fluid systems when a design is being considered.

The elusive goal for frac fluids is to be comprised 100% of the chemical H2O. In some cases, we are already at 99.83%. We may get closer if pump rates for frac jobs keep rising, proppant keeps getting smaller and properties of some concentrated additives keep improving as they have during the rapid progression to water we have experienced over the last 15 years in the shale revolution.

**Case history No. 1: Swap a CMHPG-zirconate for an ultralight guar borate system while improving production performance.**

Slickwater initiated the shale gas revolution in the Barnett Shale. To make shale oil work, the early industry consensus was that higher viscosity fluids were needed. Liberty pioneered 100% slickwater jobs in horizontal wells in the Williston Central Basin in 2011, but in the higher-permeability Niobrara in the DJ Basin, we believed higher viscosities than provided by slickwater were needed for enhanced proppant placement. As such, Liberty’s Spirit system provided a cheaper fluid alternative in the DJ Basin than the high-cost zirconate CMHPG system that was pumped in the basin before we arrived. For a while during the downturn, our low-concentration borate guar

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<th>Jobs achieving 95%+ job placement success</th>
<th>% regained permeability</th>
<th>Production (Williston example)</th>
<th>Overall fluid cost per lb placed</th>
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<td>FR</td>
<td>96.3%</td>
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<td>+++</td>
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<tr>
<td>HVFR</td>
<td>95.9%</td>
<td>60-90</td>
<td>+++</td>
<td>higher</td>
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<tr>
<td>Light gel</td>
<td>96.5%</td>
<td>50-70</td>
<td>+++</td>
<td>lower</td>
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<td>X-link</td>
<td>96.1%</td>
<td>30-60</td>
<td>++</td>
<td>moderate</td>
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1 https://www.onepetro.org/conference-paper/SPE-199760-MS
2 https://www.onepetro.org/conference-paper/SPE-181457-MS
systems became more prevalent. Now, however, DJ designs have kept moving on from this transitional fluid system to mostly slickwater pumped at even higher rates.

SPE paper 181457 documents how the change from this traditional gel system to the ultralight borate reduced overall well cost by 5%-10% while achieving 10%-30% improvements in production response in both Codell and Niobrara. Combining the numerator and the denominator reaped $/BOE reductions of 14%-35%.

Case history No. 2: Save water volume and time while changing from FR to HVFR.

Slickwater is quickly becoming the go-to fluid for tight shales. Some shales have higher permeabilities, possibly requiring higher proppant concentrations that generate more fracture conductivity. While higher velocities/pump rates can help place these higher proppant concentrations, proppant placement may still require higher viscosity for placement without screenout risk. In addition, if water is relatively expensive, the economics of the job require the use of higher proppant concentration tail-ins with HVFR systems that can help reduce water volumes.

We test a variety of FR and HVFR systems with our Chandler Model 6500 Flow Loop and Anton Paar MCR-102 Oscillatory Rheometer. Most of these products achieve about 65% friction reduction in the relatively fresh water that is typical of the DJ Basin. We look beyond viscosity to determine what fluid system can successfully carry proppant into a fracture.

HVFRs get a viscosity boost in an area of low shear rates that linear gels lack. In the graph at right, we compare the apparent viscosities of a linear gel and a high-viscosity FR. Both have a target viscosity of 20 cP at a standard shear rate of 511 s⁻¹. If we test apparent viscosities at normal shear rates above about 10 s⁻¹, these fluids behave the same. In the range below that, where we can extrapolate to “zero-shear” viscosity, the differences are significant, with the HVFR showing superior viscosity.

At ultralow shear rates, FRs can therefore sometimes provide superior proppant carrying capacity in comparison to more traditional linear gels.

An operator using a relatively expensive water source used these measurements to switch from FR to HVFR to reap water and efficiency savings. When comparing wells on an FR-only pad and an HVFR-only pad, HVFR wells were completed 1.6 days faster and required 180,000 fewer barrels of water to be completed. While the jury is still out on production performance, these changes resulted in 5%-10% completion cost savings.

CONSIDERATIONS FOR CHEMICAL ADDITIVE CHANGES

Case history No. 3: Long-term ATP and serial dilution testing helps optimize biocide product selection.

Adenosine triphosphate, also known as a molecule that represents “the currency of life,” can help identify unwanted bacteria in frac fluid and production streams. We also utilize serial dilution testing for anaerobic sulphate-reducing bacteria and anaerobic acid-producing bacteria, generally over about four weeks, to help identify the most effective biocide and the optimal loading.

In an example for the Eagle Ford, we suggested a glutaraldehyde swap to didecyl-dimethyl-ammonium chloride. DDAC is more stable at 300 degrees Fahrenheit bottomhole...
temperatures than glutaraldehyde and therefore ensures a long-term bacteria kill downhole and potentially provides microbial mitigation on production. This change for an operator represented an annualized potential cost savings of approximately $250,000/frac fleet (0.1% average well cost reduction) by using a more suited biocide.

In another example of pre-job testing and post-job monitoring for a DJ operator, sodium hypochlorite proved to be at least as effective as more expensive alternatives. In a study, we treated five wells with ClO₂/TTPC, three wells with PeroxyMax/TTPC and four wells with 12.5% sodium hypochlorite/TTPC. Wells were sampled for 12 weeks post-frac and tested for ATP.

Sodium hypochlorite can lower costs without sacrificing performance. An upstream sodium hypochlorite treatment can typically save $0.07-$0.10/bbl compared with chlorine dioxide. On a per-well basis, the cost of the 160,000 bbl/well treatment is reduced by about $15,000, which represents $/BO savings of about 0.3%. For a 50-well program, these simple measurements result in yearly savings of $680,000.

Case history No. 4: Clay swelling tests can help minimize the need for expensive KCl.

We conduct capillary suction time testing to determine if clays swell in the presence of water with additives. A slurry of ground cuttings, water and clay additive are added to a CST cylinder, and a timer measures how long it takes for a fluid column to travel from one ring to the second. A longer time means clays have more obstruction from swollen cuttings. We sometimes back this simple test up with roller oven testing.

Several operators in the Powder River Basin used this test to select a substitute for KCl, as the cheaper substitute proved just as effective in minimizing clay swelling. Operators realized average savings of $100,000-$200,000 per well (2%-4% $/BO reduction for a typical PRB well).

Case history No. 5: HCl substitute reduces water volumes and pump time.

We use HCl in several liquids-rich basins to help with perforation breakdown, open more perforation clusters and improve treatment injectivity. A new HCl substitute, Spearpoint, developed by one of our vendors, could be used effectively with wireline tools in the well while not impacting the materials reactivity on formation and its ability to clean perforations.

In a case study with a DJ operator, two wells were treated with 15% HCl, while the HCl replacement was on the last 29 stages of a third well and the last 56 stages on a fourth well. The fact that wireline tools could be lowered into the well with Spearpoint saved an average of 13.5 min/stage and about 400 bbl of water per stage. For an 83 stage well, the extrapolated savings would be 0.75 days or equivalent to 2.2% savings on the cost of the frac, not including water or third-party day rates, which translates to about 0.7% savings on well costs.

CONCLUSION

The frac industry continues to become more efficient as it has lowered the all-in delivery cost to place a pound of proppant downhole from about 50 cents in 2012 to about 10 cents today.

A few examples in this article show that a real-data approach to optimize chemical package and dosage, verified with production data feedback, can help reduce $/BO further. This relentless focus on efficiency should help us all get through the 2020 downturn.
Leen Weijers is vice president of engineering at Liberty Oilfield Services, where he began as business manager when the company was founded. From 1995 to 2011, he worked at Pinnacle Technologies, where he oversaw development of the industry’s most widely used fracture growth simulator and was responsible for fracture model calibration with fracture diagnostics.

Ben Poppel is the engineering manager at Liberty Oilfield Services, where he has spent eight of his 14 years in the frac industry. While most of his experience has been in domestic unconventional plays, he also spent time working in the North Sea and Siberia.

Joel Siegel has served as Liberty’s lab director for eight years. Involved with oilfield chemicals across drilling and stimulation for multiple service companies for more than 23 years, he has gained a wide scope of industry knowledge regarding product composition, design, marketing and performance evaluation.

Kyle George, senior technical sales engineer at Liberty, has been in the field of hydraulic fracturing since 2011. He started with Liberty in early 2013 and became district engineer for the Powder River Basin in 2015. He has since specialized in technical solutions, particularly chemical additives, with a focus on the Rocky Mountain Region.

Jon Sochovka, technical sales engineer at Liberty, joined the company in 2014 as a field engineer in the Bakken. He has since progressed through the engineering management pathway, including serving as the district engineer in the Permian Basin from 2017 to 2019. He currently holds a cross-functional role focusing on providing integral chemical and operational solutions to meet the needs of Liberty’s customers.