Originally appeared in World Oil® JANUARY 2019 issue, pg 29-32. Posted with permission.

Tunable technology improves operational efficiency in the Eagle Ford

A case study performed in the Eagle Ford has proven that tunable technology can help achieve greater efficiency gains in developing unconventional reservoirs.

JEFF LONG, DAN FU and CHRISTINE DE SARIO, BJ Services

As the development of unconventional reservoirs in North America has increased, hydraulic fracturing operations have evolved. Today, operators are looking for efficiency gains, not just from equipment, but across the entire fracturing value chain to drive down costs, reduce cycle times and improve well performance.

Much of the Eagle Ford's area of operation is in remote expanses with limited infrastructure, which can make production challenging.

One area that cannot be overlooked is the role played by fracturing fluid systems. Efficiency is driving the demand for innovative fluids that can be tailored to specific well conditions and operating environments. The days of using one completion design on multiple wells is fading, in favor of a customizable approach. The challenge becomes determining which formula works for the wells in a given field.

To test this methodology, a study of completion fluid designs was conducted that compares operations and production across several pads in Gonzales and Lavaca counties, in the Eagle Ford basin. Specifically, the operator was looking for a flexible completion fluid design that would allow field personnel to complete more stages with less shutdowns and screen-outs.

The study found that the use of a tunable friction reducer provides functionality, similar to multiple completion fluid systems, such as slickwater, a high-viscosity friction reducer (HVFR) and linear gel with a single additive, providing operational efficiencies, economic advantages and increased production.

CONVENTIONAL SLICKWATER FRACTURING

The fluid design examination began with the operator using a traditional slickwater hybrid treatment design. Slickwater treatments became popular, because of their proven ability to produce a more complex fracture network, particularly in low-permeability reservoirs.

Slickwater systems contain non-viscous, un-crosslinked fluids that enable high pumping rates to carry, and place, proppant deeper into the formation. Pumping rates of 100 bbl/min. are common, and these high-pressure pumping rates help to stimulate more rock and create complex fracture networks.

The drawbacks of this system include the need for larger volumes of water, which require more horsepower to maintain the high pumping rates and limitation on sand loading. Conventional slickwater treatments do not always get the proppant deep enough into the fracture network and the lack of polymer breakability can lead to reduced flowback capabilities, formation and proppant pack damage.

To offset the increased horsepower, slickwater typically consists of friction reducers that are designed to provide drag reduction. In slickwater designs where conventional friction reducers are inadequate, subsequent HVFR and linear gel designs are utilized. More recently, HVFRs have seen increased usage because of the improved proppant carrying capabilities; however, the use of friction reducers, together with linear or crosslinked guar, has traditionally introduced increased treatment cost and operational complexity.

For the study, the operator completed ten stages with the slickwater hybrid treatment. It required an additional linear gel to achieve the extra viscosity needed to effectively place the proppant. After finishing the stages, the operator was experiencing NPT, shutdowns and screen-outs, due to reservoir properties that were difficult to break down, along with higher surface treating pressures.

TUNABLE TECHNOLOGY

When the operator approached BJ Services, the company proposed a tunable friction reducer that provides the ability to run at reduced concentrations.

The purpose of tunable technology is efficiency. Tunable friction reducers are polymers that enable adjustments to the fluid properties in real time. They are a one-fluid solution, as concentration levels can be tuned to achieve the desired outcome. They have a much higher molecular weight than guar or guar derivatives; therefore, they can be used at very low concentrations to achieve drag reduction while minimizing horsepower requirements. It can be run at half the concentration of conventional friction reducers while providing the same level of drag reduction.

Fig. 1. Surface treating pressure observed with 1-gpt conventional FR, pumped throughout stage 11. A pressure decrease is apparent, when ThinFrac MP is increased in concentration during minutes 105–125 and 165–180.

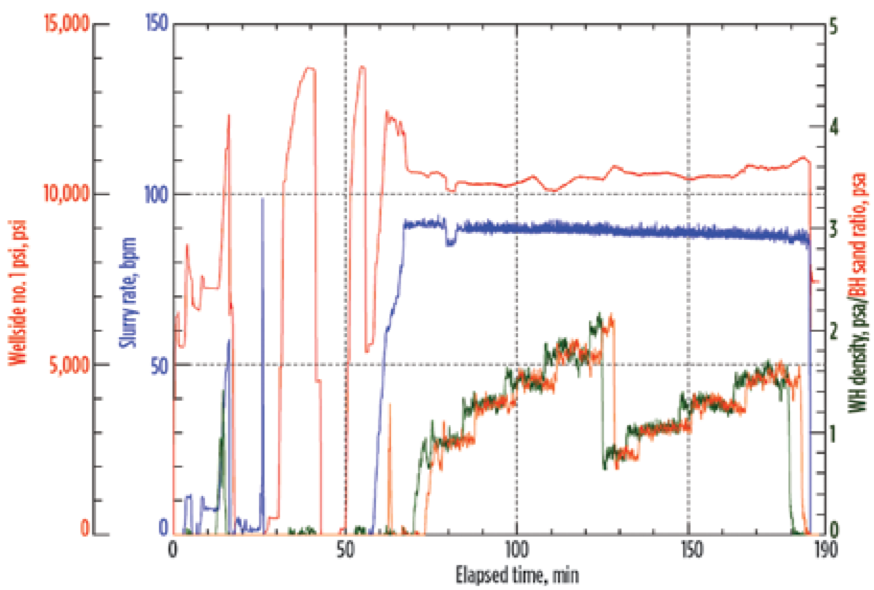
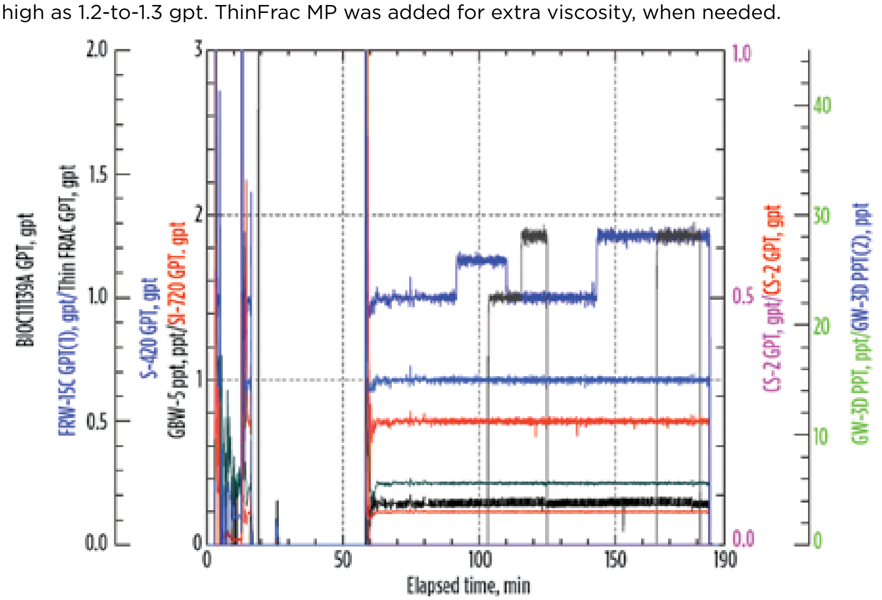


Fig. 2. A conventional friction reducer pumped at a 1-gpt minimum and adjusted to as high as 1.2-to-1.3 gpt. ThinFrac MP was added for extra viscosity, when needed.



As mentioned, most friction reducers do not have sufficient viscosity for proppant transport, so HVFRs are used. With a tunable friction reducer, by simply increasing the concentration, it produces sand transport capability, equal to HVFR and linear gel. This versatility provides greater flexibility for rapid design changes, and it also can reduce NPT related to operational issues (equipment maintenance, failures, etc.) caused by having to use a gel hydration unit by adjusting the concentration on the fly. Another aspect of the tunability is to ensure flowback capability. This tunable friction reducer is engineered with breakable linkages along the polymer's backbone. Current conventional friction reducers are predominantly polymers with carbon-carbon backbones, which are difficult to break, even in the presence of an oxidizer breaker.

By controlling how the chemistry behaves, to precisely break the polymer's molecular structure, the smaller molecules allow for easier flowback, with little to no proppant pack or formation damage, giving almost 100% regain of permeability. It leaves no residue polymer or polymer fragments on the fracture surface or in the proppant pack, which helps maximize production.

Moreover, this tunability is achieved using less equipment and additives, reducing the operational footprint and overall complexity.

EAGLE FORD

As previously mentioned, the operating environment plays a role in choosing the right technology. For this examination, the wells were in the Eagle Ford.

The Eagle Ford shale is a unique geological formation, because of its capability to produce both natural gas and oil. The basin covers 20,000 mi^2 in south and central Texas, stretching across 24 counties. There are nearly 12,000 producing wells.

The majority of these wells are drilled horizontally from multi-well pads.

Like other shale plays, this geological formation has low permeability, preventing natural hydrocarbon flow. Because oil cannot flow easily through ultra-low-permeability rock, high initial production rates from shale formations often decline rapidly. Therefore, an efficient completions program can improve the wells' longer-term economic viability.

The Eagle Ford has some distinct characteristics that can make production challenging. The play exhibits an extremely tight formation rock matrix. Tighter sections are thin layers of varying compositions and weak interfaces in the rock, meaning that injected fluids become diverted to the paths of least resistance. This feature creates natural fracture variability, requiring more pressure generation at the surface. Treatment pressures during fracturing operations in the Eagle Ford are some of the highest applied during any oilfield pressure pumping operation.

Furthermore, much of the Eagle Ford's area of operation is in remote expanses with limited infrastructure. Logistics management—which includes moving equipment, people, materials and parts—requires sophisticated coordination. These remote locations can introduce operational complexity, as well as additional costs.

Because of the aforementioned challenges, the operator had to take into consideration the higher treating pressures and logistical complexity when selecting the fluid design. The Eagle Ford operator needed a fluid design that could achieve friction reduction, and maximize proppant transport, while accommodating the pressures and minimizing complexity and costs.

OPERATIONAL SUCCESS

The operator started fracturing operations on a two-well pad. Overall, they had 20 to 30 wells, with approximately 35 stages per well.

For the first ten stages of both wells, the operator used a conventional slickwater treatment, the same design that had been used on previous wells. During the fracturing operations, the operator experienced extremely high pumping pressures, causing equipment shutdowns, NPT and delays. Operator personnel also kept a gel unit rigged-in, on location, as a secondary backup.

For the next 15 stages, the operator

Fig. 3. During stage 12, the average rate was 93 bpm, in comparison to the 89 bpm from the previous stage.

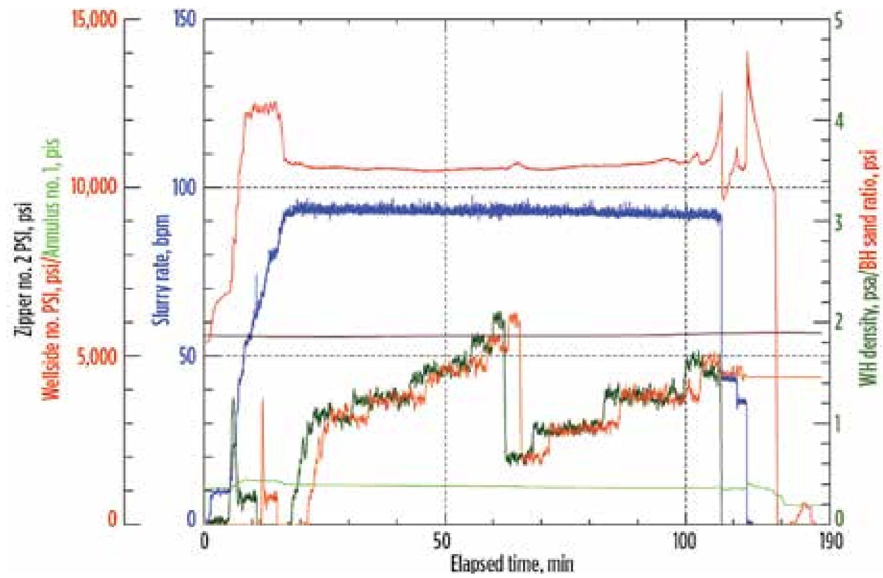


Fig. 4. ThinFrac MP pumped at 0.5 gpt, achieving an average 3 bpm more throughout the stage. Similar surface treating pressures were observed.

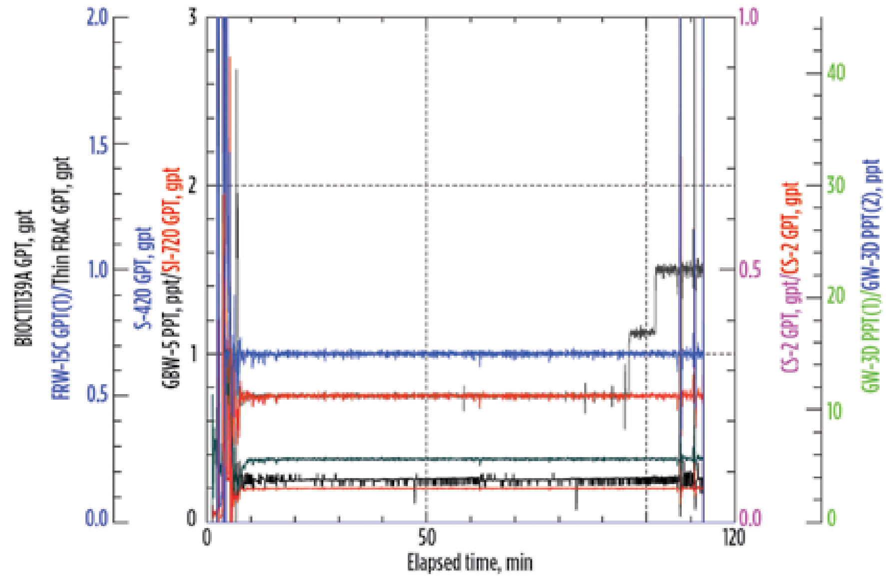
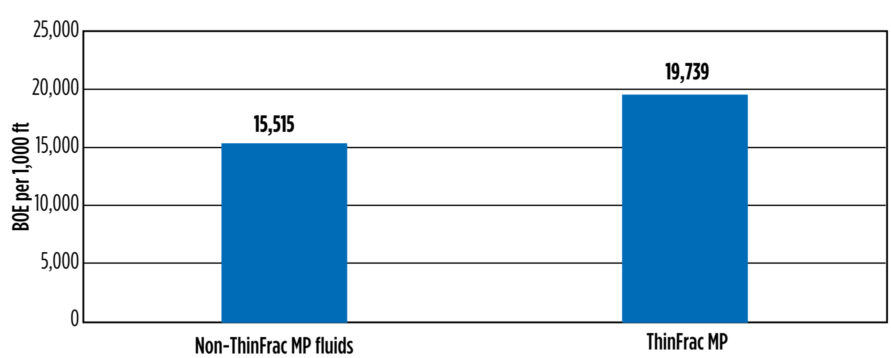


Fig. 5. In a study of wells within a 5-mi radius of the two-well pad, based on data from RS Energy, 180-day boe produced per 1,000 ft from the ThinFrac MP wells was 27% higher than the non-ThinFrac MP wells.



switched to a tunable friction reducer. Wellsite personnel started to run the enhanced polymer at a higher loading of 1 gallon per thousand (gpt). To be on the safe side, they kept the gel unit on location. After seeing enough performance results, the enhanced polymer was tuned to run at half the loading, at the concentration of 0.5 gpt. On average, fluid concentrations with ThinFrac MP were 20% less than conventional friction reducers and eliminated the need for guar gel.

The operator saw equal performance with a lower concentration. Consequently, less horsepower was needed at the surface while still ensuring effective results. By reducing the concentration, the operator experienced the same level of viscosity, but the pressures were 10% lower, compared to the slickwater hybrid treatment. This lower rate enabled the proppant to be carried deeper into the fracture network, **Figs. 1–4.**

To effectively pump the fluids, the company used its unique Gorilla high-pressure pumps. These heavy-duty pumps provide up to 2,700 hydraulic horsepower (HHP) at pressures up to 20,000 psi. The high-capacity fuel tank enables 4 hr of continuous pumping operations at maximum horsepower, reducing refueling and backup equipment requirements. The higher horsepower pump allowed a 16-pump fleet, compared to the standard 20-pump fleet. In addition, because the polymer was a single-fluid solution, no specialized equipment was needed to pump the chemistry, reducing the operational footprint.

Furthermore, when the operator experienced increases in pressure, the friction reducer concentration was run at a higher loading of 1 gpt, to increase the viscosity. The fluid adjustment was made on the fly, with no disruption to the ongoing operations or increasing the surface horsepower requirements. After the first few stages, the operator was confident in the technology's performance and removed the additional gel unit, eliminating equipment and extra additives, as well as a further reduction to the footprint.

The operator completed 15 stages with the tunable friction reducer. Because the technology could be tuned effectively, the operator was able to complete the 15 stages more quickly and with less downtime than the previous ten stages. The flexible design of the friction reducer allows completion of more stages with less shutdowns and screen-outs.

Overall, production results taken over the first 180 days will show that wells completed with the tunable friction reducer performed better, in terms of initial production and cumulative production, which are normalized by lateral length and proppant volume. In a study of wells within a 5-mi radius of the two-well pad, based on data from RS Energy, 180-day boe produced per 1,000 ft from the ThinFrac MP wells was 27% higher than the non-ThinFrac MP wells, **Fig. 5.** The operator continued to use the technology on subsequent wells as its exclusive friction reducer and has since fully adopted the enhanced friction reducer for use on all its wells in the region.

CONCLUSION

The study has proven that tunable technology can help achieve greater efficiency gains in developing unconventional reservoirs. Improved well performance can be attributed to the enhanced proppant transport capabilities and greater regaining of conductivity. Finally, cost-savings are seen through simplified delivery, smaller job site footprints and reduction in NPT. WO

JEFF LONG is a senior account manager at BJ Services. He has 28 years of experience in the pressure pumping industry. Mr. Long began his career with Dowell-Schlumberger in the Rockies and Alaska, eventually moving into offshore and deep water. He has worked in several of the major basins around the world, providing engineering solutions to his customers.

DAN FU is the director of technology at BJ Services. He has over 20 years of experience in strategic planning, developing and commercializing innovative technologies. Mr. Fu holds a BS degree from Beijing University, a PhD in chemistry from the University of Southern California, and an MBA from Colorado State University.

CHRISTINE DE SARIO brings five years of industry experience to the BJ Services team. She began her career as a field engineer in hydraulic fracturing operations and is currently in business development. In 2013, Ms. De Sario graduated from UCLA with a BS degree in chemical engineering.