Surviving the Downturn

OFFSHORE DRILLING AND COMPLETION

NATURAL GAS PROCESSING AND HANDLING

HISTORY MATCHING AND FORECASTING

HIGH-PRESSURE/HIGH-TEMPERATURE CHALLENGES

FEATURES
Improving Shale Completions
Fracturing Expectations vs. Reality
SPE President and Board Nominations
Two places that illustrate the mounting challenges facing the shale business are the Bakken Shale in North Dakota, where the number of working rigs is one-third what it was a year ago, and the Fayetteville Shale in Arkansas, where there are no more working rigs.

Steve Mueller, the outgoing chairman of the board and former chief executive officer of Southwestern Energy, the company that discovered the Fayetteville Shale, noted how the current environment has made it harder to drive innovation forward even as it becomes more important than ever.

“How in the world do I learn at the speed I was learning at before when I am not drilling as many wells, when I am not doing as many fracs, and when I don’t have as much money?” he said. “And the conclusion I come to is that we have got to do it a different way and we have got to do it a lot faster.”

Mueller spoke in February before a room of engineers and service providers at the SPE Hydraulic Fracturing Technology Conference in The Woodlands, Texas, where some of the innovations spurred by the need to change were presented. But because so many companies have laid down so many rigs, it will take a significant price recovery before the latest advancements and efficiencies make a big impact on the shale sector.

Getting More From More
A good example of a company executing a strategic retreat is Hess Corporation. In 2014, the company had 17 rigs running in its Bakken program. At the start of this year, that number was two. Despite the major pullback, the company has moved forward on two key completions strategies: increasing the number of stages from 35 to 50 and switching to a cheaper, and more effective, fracturing fluid system.
To help determine the optimal number of stages, Mariano Gurfinkel, the planning manager for the global onshore business unit at Hess, said the company mined public data from more than 10,000 wells in North Dakota. “We can learn from that,” he said. “It is like looking at other people as your own pilot.”

Hess then followed up on the data with a real-world pilot program. It saw that increasing the number of stages by nearly 40% generated an average initial production uplift of 20%. The company is also using sliding sleeves for the operational gains they provide and exploring the idea of using more proppant per stage.

Gurfinkel added that Hess believes its 50-stage wells are accelerating early-time production, which is bolstering cash flow, but have not been on production long enough to say whether they will increase ultimate recovery.

Mark Pearson, president of the small independent operator Liberty Resources, described how his company is exploring the idea of using more proppant per stage. Without elaborating, he added that Liberty has reduced its completion costs, Pearson said the company has decided that instead of adding more frac stages per well, it will pump more proppant per stage and has switched from premium proppant to less expensive sand. Without elaborating, he added that Liberty has reduced its completion spending caps on their designs are losing the most.

“It is very tempting for us in times of low prices to just say, ‘Let’s cut the number of frac stages, let’s cut the amount of proppant, let’s cut the engineering out of our fracs,’” Pearson said. “But from our data, and looking at the case studies, we don’t think that is the right way to survive in 2016.”

As Liberty continues to operate only a single rig in the Bakken, its new goal is to do a better job of engineering completions rather than maintaining the geometric “cookie cutter” approach. To cut costs, Pearson said the company has decided that instead of adding more fracturing stages per well, it will pump more proppant per stage and has switched from premium proppant to less expensive sand. Without elaborating, he added that Liberty has reduced its completion chemical additive package to “what is proven to be needed rather than what sounds like a good idea.”

Cutting Chemicals, Increasing Performance

Other companies have adopted a simpler chemical mix for their completions too. Hess is working with Calfrac Well Services on a formula that uses slickwater fluids to perform like a more expensive guar-based crosslinked gel. Max Johnson, a completions engineer at Hess, said the move to a high concentration of emulsified polyacrylamide, commonly used in slickwater treatments as a friction reducer, has increased production by an average of 10%.

Overall, four out of five wells in which friction reducer was used in the place of crosslinked gels have improved production. “It is a pretty big deal when you know that not only are you getting that percentage of uplift, but that many more [wells] are doing better,” Johnson said.

Compared with a typical slickwater job, the volumes of friction reducer used with this approach can be anywhere from four to 10 times higher. Johnson said the formula Hess used was nearly 25% cheaper than the crosslinked fluids it was previously using which required completion crews to manage up to 13 different chemicals. This presented a higher risk of spills and also a higher degree of difficulty involved with achieving optimal pH levels.

Aside from the friction reducer, the only other major component to the simpler mix is a gel breaker. However, testing has shown that removing the breaker would have no effect on completion quality and would further reduce costs.

Jeremy Meehleib, lead completion enhancement engineer at Calfrac Well Services, has been working with Hess on the implementation of the friction reducer formula and said it is now being trialed in the Three Forks Shale, a deeper and much tighter layer found under the Bakken.

He explained that because the Three Forks is a “notoriously more difficult to complete formation,” some changes to the fluid mix have been made. “We’re having success and moving forward,” he said. “I think we will be just where we are with the Bakken treatments relatively soon.”

One of the major advantages of using friction reducer is that it is also an excellent viscosifying agent which has allowed treatment pressures to be lowered by as much as 550 psi. Meehleib said that a lower pressure means there is a greater margin of safety on-site, and target pumping rates can be reached sooner than with the crosslinked gels. Further, the friction reducer fluid is able to carry...
more proppant per gallon through the lateral section and into the formation compared with crosslinked gels.

Outside of the Bakken, Calfrac has so far only used the friction reducer in Canada as an additive to nitrogen foam treatments. The company believes the technology has much wider applications and is marketing it to other operators using both crosslinked gels and slickwater.

The Powder Option
Before its drilling program went on hiatus, Southwestern also piloted and then adopted a friction reducer fracturing fluid for use at its Fayetteville operations at the end of 2014. In this case, Southwestern used powdered friction reducer as an alternative to the emulsified variety and achieved significant savings on its fresh water costs. SNF, the largest maker of polyacrylamide in the world, developed the idea of using dry friction reducer as a fracturing fluid additive and the equipment to deploy it in 2010. The Stim-Lab research consortium has since carried out multiple studies to validate its potential, yet during the boom cycle, few companies were willing to change their operations and use such a novel fracturing fluid.

“But as the price of oil has dropped, it’s driving people more in the direction of innovation and to come up with new ways of reducing their treatment costs,” said Russell Thorpe, the technical manager of fracturing and completion chemicals at SNF.

To be sent into the treatment lines and downhole, the powder is mixed using a truck-mounted hydration unit designed by SNF. Thorpe worked on the project with Southwestern and said compared to the emulsified friction reducer, the powder contains three times more active content which lowers the cost of transportation and logistics.

In the Fayetteville operations, he said that surface treating pressures were able to be reduced by 500–1,000 psi. After observing performance improvements in the initial wells, engineers began testing for proppant transport capabilities. They found that increasing the concentration of dry friction reducer made it possible to pump about 5.5 lb/gal of proppant into the well, more than twice what could be achieved with a standard slickwater treatment.

“‘When you increase the proppant loading, the pressure of the fluid is going to gradually increase as you put more and more proppant into the fluid,’ Thorpe explained. ‘And you would normally have to drop your injection rates down to accommodate that.’”

But not so with friction reducer. The Southwestern stimulations were able to maintain high injection rates while continuously increasing the proppant loading and displacing water. Thorpe said the only limiter was how much sand could be loaded into the blender at one time. Southwestern reported that when it used dry friction reducer for these so-called “reduced fluid completions” it was able to improve production and cut water costs by USD 250,000 per well.

For Further Reading
SPE 179160 Completion Optimization in the Fayetteville Shale Utilizing Rate Transient Analysis for Candidate Selection by B. McDonald and T.H. Wright, Southwestern Energy.


SPE 179154 High Concentration Polyacrylamide-Based Friction Reducer Used as a Direct Substitute for Guar-Based Borate Crosslinked Fluid in Fracturing Operations by M. Motiee, M. Johnson, Brian Ward, Hess Corporation, et al.

**Benefits of Using Friction Reducer Fracturing Fluid**

- Excellent low-shear viscosity and high viscosity at high-shear rates
- Low rate of proppant settling
- Water displaced by the extra proppant saves money
- Less damage to proppant packs and better well cleanup
- 500–1,000 psi reduction in fracture treatment pressure
- Lower pressures may result in lower fuel costs and less stress on pumping units
- Lower heating requirements can save money, especially in winter months