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2020 Hydraulic Fracturing Techbook

A supplement to
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Hydraulic Fracturing
The 2020 Techbook

A supplement to E&P Plus and Oil and Gas Investor

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Shale's Climb Back

The history of shale development and hydraulic fracturing in the U.S. is accentuated by major developments that helped chart its course in the greater role of energy development: Mitchell Energy's groundbreaking technology in fracking wells in the Barnett Shale, $100/bbl oil in the early 2010s, the subsequent collapse in prices, the move to massive proppant volumes in the Eagle Ford, and the "lower-for-longer" era, just to name a few.

Today the industry finds itself amid perhaps its greatest challenge—emerging from previously unseen demand destruction caused by a global pandemic and a price war.

Despite the downward pressure on shale, the industry is fighting back. Producers, and particularly natural gas producers, are ramping up production once again as demand slowly climbs back. Perhaps now more than ever, operational efficiency gains and optimization are the name of the game.

The technical challenges the industry faced pre-COVID-19 take on an even greater importance now, such as identifying the most optimal well spacing, increasing stimulated rock volume and drilling the optimum lateral length. Service companies are responding in kind, bringing to the market innovative technologies and tools that continue to lower the cost of bringing oil and gas to the surface while reducing risks along the way.

It remains to be seen if U.S. activity will ramp up enough to quickly reach the peak of 13 MMbbl/d that the industry achieved in early 2020. Demand will have much to say about that.

But now that shale is up off the mat, it's heading in the only direction it knows—forward.

—Brian Walzel, Senior Editor

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On the cover: Although not achieving previous highs, the number of frac crews throughout the U.S. will continue to climb throughout 2021. (Source: National Oilwell Varco)

Finding the Right Balance

Emerging trends help companies fine-tune their well designs and grow production post-downturn.

By Brian Walzel, Senior Editor

Although the magnitude and quantity of disruptive events in 2020 continued to expose its vulnerabilities, the rumors of shale's death have been greatly exaggerated. The effects of price wars and demand destruction are well analyzed and much discussed, but the slow climb back for the hydraulic fracturing industry is well underway.

E&Ps are finally getting around to completing and putting on production their multitude of DUCs, completions continue to be honed and optimized, and producers are finding the right spacing for their wells after some notable—and costly—trial-and-error experiments.

While R&D budgets, along with thousands of jobs, were slashed over the summer as companies looked to quickly shed costs, the path back to profits and productivity will undoubtedly include greater efficiencies downhole, particularly in the completion phase. The fully automated completion job continues to be the carrot on the stick that service providers are chasing, and the incremental gains toward that goal are showing such an achievement might be possible in the not-so-distant future.

Meanwhile, the energy transition is opening up new opportunities for operators and service providers alike to win back investor sentiment and achieve greater cost efficiencies. These factors add up to an inflection point for the North American shale industry.

"With the possibilities of external cost-cutting—for example, on contracting and leasing—all but exhausted, oil and gas companies now need to look internally," McKinsey and Co. stated in an August report. "That means reinventing their operating models to improve efficiency and reduce greenhouse-gas emissions."

New fracturing trends

In an era of consolidation in the fracking market, and intense competition among pressure pumpers, operators have capitalized by optimizing their frac designs. The zipper frac has proven to be a reliable cost-saver, but an emerging technique could cut pumping time in half. Simultaneous hydraulic fracturing, or simul-fracs, is a process in which two horizontal shale wells are stimulated simultaneously with one pressure pumping fleet.

"The real focus right now is trying to do more with less and maximize the efficiency, not necessarily just in operations, but on the capital and operating cost," said Ian Henkes, senior vice president of operations with NexTier. "The gains will come more on applying these techniques like simul-fracking. In order to have a successful operation for simul-fracking, you need certain things to align. You need the proper well spacing and the proper pad size for this technique to be really effective."

Henkes said the number of simul-frac jobs over the past year has increased about 15% versus traditional zipper fracs. However, widespread adoption for simul-fracking may still be some time off, as operators hold off on drilling new wells and instead work to complete their DUCs, which Henkes said typically do not meet the requirements for simul-fracs.

"Once we get through the DUC count that we have, which is probably going to take us pretty far into 2021, I think that's when we're going to start to see the real transition to more simul-fracking—once the operators start to drill more wells and they design their pads to meet the requirements for simul-fracking."

With drilling activity only slightly recovering since a near-total shutdown in June, operators have turned to the proliferation of DUCs to maintain or grow production. As Rystad Energy noted in a September analysis of DUC trends, the recovery of fracturing operations in the U.S. is happening mostly as a result of the high inventory of DUCs. On March 27, the U.S. produced 13 MMbbl of oil, which dropped to 9.7 MMbbl on Aug. 28, according to the U.S. Energy

Oppostite page: Service companies like NOV have been making incremental advances toward fully operated frac and completions operations. (Source: National Oilwell Varco)

Liberty Oilfield Services has recently emphasized the importance of achieving longer lateral lengths and pumping fewer stages. (Source: Liberty Oilfield Services)

Information Administration. That amount had ticked up to 10.7 MMbbl by early October.

Rystad estimates enough DUCs currently exist to sustain operations with the current rig count well into 2021.

"Beyond that, I think that the rig count is going to have to start coming back up to keep the completions activity from dropping after the second quarter," Henkes said.

Completion designs

One of the primary drivers behind the production gains over the past five years of unconventional development has been the optimization of the well completion stage. Dialing in the right mix of lateral lengths, stage spacing, proppant and fluid pumping helped propel the U.S. to be the world's largest oil producer. Tighter cluster spacing and the move to slickwater fracs helped increase stimulated rock volume (SRV), and the transition to pumping huge amounts of proppant opened greater amounts of fractures, exposing significantly more oil and gas to the wellbore.

According to Rystad, shale producers were fracturing a little more than 900 ft/d and pumping 1,600 lb/d of proppant in the first quarter of 2018. By the third quarter of 2020, those numbers increased to stimulating more than 1,500 ft/d and more than 2,800 lb/d of proppant.

But there is some indication completion intensities may have leveled off. Rystad reported that since the third quarter of 2017, fluid intensity has hovered at a little more than 40 bbl/ft while proppant intensity has remained between 1,750 and about 1,900 lb/ft.

Meanwhile, Leen Weijers, vice president of engineering with Liberty Oilfield Services, said one of the big macro changes across the different shale basins is the evolution of stage spacing.

"One of the biggest things we have seen as a company and as an industry has been letting go of the stage intensity criteria that was really key over the last decade," he said. "On average, our industry went from 500 ft per stage to maybe 200 ft per stage over a period of about eight years or so. Now, that stage intensity criteria has relaxed a little bit, and they're going to 250 ft or so per stage."

Weijers added that Liberty has specifically focused on being more efficient in creating perforation clusters that lead to enhanced production. In limited-entry perforation, or extreme limited-entry perforation, changing the cluster design to fewer perforations with more clusters per perforation can lead to increased production.

Mike Mayerhofer, Liberty's director of technology, echoed the importance of achieving longer stage lengths and pumping less stages while also maintaining the same cluster spacing.

"There is a lot of effort going on right now from companies trying to figure out the perforating strategies to make sure that the fracture treatment distributes the fluid and proppant as evenly as possible into all of the stage clusters (can be as high as 25 clusters per stage)," he said. "Some advanced modeling of fluid dynamics in the casing attempts to figure out the impact of shooting the perforation hole up


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NexTier's NexHub serves as a data application and analysis that uses artificial intelligence and predictive measures to optimize preventative maintenance and servicing of equipment. (Source: NexTier)

through the casing or down through the casing or angled, and how that affects the distribution of the proppant through each cluster. Some of the supermajors are running these types of models right now."

Amid the current oil and gas environment, Henkes added that it is unlikely many companies will look to experiment with new completion designs and instead continue to apply proven practices.

"Lateral lengths seem to have stabilized across the board to between 7,500 ft and 10,000 ft," he said. "There is a benefit in having ultralong laterals, which have the potential to lower the cost per boe. The flip side, though, is it can be a higher risk in terms of drilling, running casing and cement."

Well spacing

Among the most closely watched oilfield transitions is that of well spacing. In efforts to drain as many hydrocarbons from their acreage as possible, producers pushed the limits of pad designs and the number of wells those pads could hold, sometimes more than 10 wells per pad.

But as well interference problems emerged and frac hits began to show production degradation, the industry hit the brakes. Concho's "Dominator" project, which featured 23 wells on a single pad, served as the warning sign after the company acknowledged they placed the wells too close. The fallout was immediate. Concho's share price fell 22% in a single day, resulting in more than $4 billion in single-day market value loss.

Compounding the issue of well spacing is the need to appease the potentially conflicting desires of operators, engineers and investors, and the goals of targeting either returns or total value.

"There is definitely a lot of effort now, especially as companies slow down their completions, where companies are looking at their well spacing issues," Mayerhofer said. "Some companies have spent quite a bit of money to do diagnostics to evaluate production interference between wells. There is no question in a lot of areas that wells are communicating. We're taking some communication into account, but are the economics still favorable for that well spacing? If they are not OK, if the wells' production deteriorates too much based on interference, then they start relaxing the spacing."

At this year's Unconventional Resources Technology Conference, Rystad Energy presented the findings of a well spacing analysis of nearly 7,000 wells in the Permian Basin. Rystad analyzed well spacing and productivity measured by IP 180/ft, which Rystad explains as reported IP over the first six months divided by the perforated lateral length of well in the sample.

The analysis generally revealed that production declines occurred when the number of wells per section totaled more than six. For example, in the Midland Basin Wolfcamp, pads with six wells per section produced an IP 180 of 14.9, an amount that steadily dropped on pads with an increasing number of wells, down to an IP 180 of 12.7 on pads with 10 or more wells.

Similar production trends were identified, particularly in the Delaware Wolfcamp and Bone Spring in Lea County wells. One outlier, however, was in the Delaware Wolfcamp in Reeves County. There, six-well pads produced IP 180s of 19.1, increasing as the number of wells per section increased, up to IP 180 of 22.8 for nine-well pads.

Still, Rystad derived that upspacing in the Permian would likely lead to better production.

"We conclude that the range of six to eight wells per standard spacing unit is the most popular and also the optimal for most landing zones and areas of the Permian Basin," Rystad reported. "There are a few cases of well productivity and rate of return deterioration before the number of wells per unit reaches six. There are also a few cases of no significant interference for 10 wells per section, yet those cases are typically accompanied with low proppant intensity."

The service industry has been hard at work adopting technologies and tools that can either predict when well interference issues may occur, or lessening the impact of frac hits. Weijers explained that one such tool is Liberty's WellWatch system, which provides offset well pressure measurements.

Analyzing offset well pressures is emerging as a tool to limit far-field fracture growth and provide indicators to potential well interference issues.

Weijers said Liberty's recent acquisition of Schlumberger's OneStim frac business will enable Liberty to enhance its well interference mitigation efforts.

"Schlumberger has a variety of fiber technologies, called Broadband, with some of it intended to work as a far-field diverter so we can distribute fracture growth more equally over different perforation clusters," he said.

Weijers said it was important to understand differentials in fracture growth and how to better design every perforation cluster to distribute proppant and fluids that are being pumped downhole.

"I think there is great synergy between Broadband and our WellWatch diagnostic well interference measurements to ensure our customers that SRV is maximized in the space between wells, but that any unnecessary and excessive overlap between fractures from different wells is avoided," Weijers said.

Automation/digitalization

While drilling operations have seen the most momentum and adoption in the automation space, well completion automation still proves to be mostly elusive. And simply due to the nature of technology adoption in the oil and gas space, it is unlikely full frac automation will take place overnight. Instead, microevolutions are occurring along the way, ones that in and of themselves may only solve a single completion challenge, but from a macro perspective serve as a brick in the wall.

Jon Walters, vice president of advanced analytics, controls and digital with National Oilwell Varco (NOV), explained that taking a holistic approach to designing a well's life cycle could serve to enable more automation abilities in the completions space.

"When you're talking about frac efficiencies, we assume those completions are contained within the completions world," he said. "But are there decisions made during the drilling process that also have an impact on the completion process? As we develop our internal data aggregation platforms and our completions portfolios, we look to see if there are any overall holistic efficiencies that we can begin to stitch together."

Real-time condition monitoring helps prevent NPT and avoid costly equipment failures. (Source: National Oilwell Varco)

Walters said one of the processes most readily adaptable to machine learning automation and that can offer the most immediate tangible return is condition-based monitoring, which he called the "Holy Grail" of machine learning.

"When a failure of a valve or seat happens, we can come back with terabytes of data, and our scientists can identify the failures and expand the amount of time before the failure so that we can collect those data," he said. "That's where we're investing a lot of our machine learning resources and data science resources."

The Achilles heel for frac jobs and completions is nonproductive time (NPT), whether it be caused by operational inefficiencies or equipment failure. The management of equipment health can ultimately save a company millions, as NexTier's Henkes said.

"Every piece of equipment that we have in the field right now on frac, wireline and pumpdown is transmitting real-time data," he said. "We have equipment specialists, engineers and maintenance personnel with a lot of experience who monitor this information. We built an automated alerting system that notifies our equipment health technicians in our NexHub."

Since NexTier implemented its NexHub alert system, the company has recorded more than $6 million in savings.

Any step along the automation path begins with data collection, and the proper application of those data. In the most tangible way, data collection can help keep people off the well site, Walters said. Instead, they can be located more safely in an office environment where they are then provided with actionable information from data collected minutes prior, whereas in the past those same data could be days or even weeks old.

Scott Hall, NOV product line manager, added that data gathered during the early portions of the well's planning and construction—such as geosteering data, drilling information like ROP and gamma data—can all be merged and applied to optimize the frac and completions job.

"There is so much complexity in an automated frac job," Walters said. "There are parts of that we are focusing on. We are trying to boil it down to today, tomorrow and not necessarily the future. The challenges our customers have today are different than they were six months ago and 12 months ago." ■

Refracturing for Greater Recovery

A single-trip system activates without the need to drop balls or darts down the ID of the work string, which saves rig time.

By Scott Benzie, Coretrax

Operators have attempted many techniques utilizing more modern frac designs to recover the reserves left behind in understimulated, older wells. Some have used particulate diverters to isolate and divert flow, while others have involved coiled tubing (CT) and packers. While the primary driver for any refracturing work is to boost base production and unlock stranded reserves with low capital investment, tangible and financial success depends predominantly on isolating existing perforations.

Coretrax has developed ReLine MNS technology, which provides a single-trip solution with no shoe milling. The technology clads and seals various wellbore integrity concerns with minimal loss of inner diameter (ID), while providing high burst and collapse ratings (Figure 1).

The cased-hole system is designed for deployment on jointed pipe and can cover long or short intervals from 30 ft to 7,000 ft. It can be configured to expand and seal across various ID restrictions in the wellbore such as nipples or frac sleeves.

This technology allows mature wellbores to be recompleted enabling refracturing with modern frac designs, as successfully demonstrated in an older Bone Spring Formation well with vintage frac completions in southeast New Mexico.

Isolating existing perforations

The Bone Spring Formation lies directly under the Delaware Mountain Group and over the Wolfcamp Formation. It consists of interbedded (settled between existing layers) siliciclastic, carbonate and shale rocks up to 4,000 ft thick and is divided into four intervals—each of which has very low permeability.

FIGURE 1. ReLine MNS technology provides a single-trip solution. (Source: Coretrax)

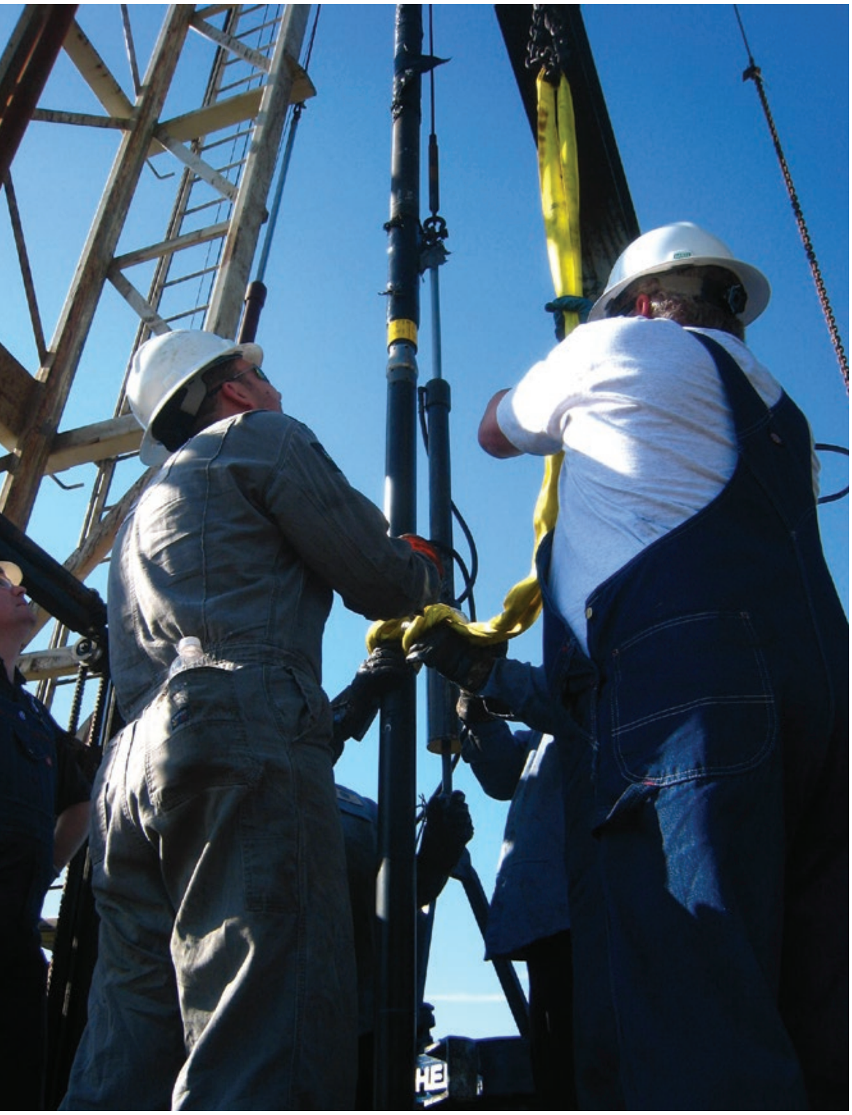

FIGURE 2. The ReLine MNS has the ability to leave the expanded liner in neutral while maintaining the speed of expanding the liner using overpull. (Source: Coretrax)

With the introduction of hydraulic fracturing and horizontal drilling, hydrocarbon production has increased considerably. The number of producing wells in the Bone Spring grew from 436 in January 2005 to 4,338 wells in mid-2019, when average monthly production reached 0.6 MMbbl of crude oil and 1.7 Bcf/d of natural gas.

While the U.S. Energy Information Administration (EIA) expects Bone Spring production to drive growth in the Permian Basin, the produced volumes in vintage wells were lower than new wells in the same acreage. Therefore, the forecasted EUR values, using the original production trends, were not economic.

Additionally, the level of depletion around the wellbore was presumed to be small. As the wellhead was rated to 10,000 psi, a wellhead isolation tool was not needed to test the casing to 6,200 psi, which was 80% of the burst rating and the expected pressure during the frac treatment. Since the produced volumes were low, the level of depletion around the wellbore was presumed to be low. Additional frac stages with higher proppant volumes per foot would increase the stimulated reservoir volume and would contribute to higher recovery.

Single-trip tool

A heel frac planned for this well had run into operational issues, and eventually it was decided to perform a full-lateral refrac since the well passed the refrac selection criteria. Unlike other expandable systems, the ReLine MNS running tool configuration can be decoupled from the inner string expansion mechanism during the hydraulic expansion process. This allows the liner to be expanded in multiple load conditions. Importantly, it can be left at a neutral position before anchoring the top seal and exiting the liners with the inner string. This neutral load condition is critical for reliability in severe fracturing downhole environments.

In preparation, artificial lift equipment was pulled from the well and a retrievable bridge plug was set at the planned depth on top of the expanded liner to test the integrity of the original 5½-inch casing. Multiple cleanout trips were needed to clean the lateral wellbore section. To ensure the liner could be run to the intended depth and expanded, a drift was performed. The liner was then run in-hole on an inner string without any issues (Figure 2).

The expansion cone was activated hydraulically to expand the bottom anchor seals, securing the liner to the original casing. The remaining liner was then expanded mechanically using overpull. At the last joint, weight was slacked off to put the expanded liner into neutral, relieving all the tension in the liner joints. The top anchor seals were then expanded hydraulically to anchor the top of the liner to the original casing.

Greater reliability and increased production

To test the full well integrity of the liner after installation, a bridge plug was run and set at the end of the expanded liner. A pressure test to 6,200 psi was obtained. Subsequently, the well was hydraulically fractured using a modern frac design with 22 stages over 3,300 ft of the lateral. There were no issues with placing the sand and no isolation-related issues during the treatment. The well was cleaned out using a CT unit.

"Like any operation, the risk of doing what is well known but expensive compared to what is unknown and more cost-effective is the daily conundrum to support the evolution of effective, productive and sustainable drilling and completion."

—Scott Benzie, *Coretrax*

IP after refracturing was double the original completion IP. The forecasted EUR almost tripled, and the rate of return was more than 100%. Among other expandable technologies trialed on this project, the ReLine MNS had the lowest operational cost of the four systems tested by the operator with minimal nonproductive time.

Mechanical isolation using expandable liner technology is a more reliable and effective method for refracturing wells than cementing casing to re-line the previous producing interval. With the ability to leave the expanded liner in neutral while maintaining the speed of expanding the liner using overpull, the operator stated this would be the system of choice for future full-lateral refracturing.

FIGURE 3. Frac plug operations can often result in the generation of debris in the wellbore. (Source: Coretrax)

Refracturing unlocks unrecovered reservoirs

It is estimated that drilling and completion of a new well can range between $5 million and $10 million per well to perform. In today's cost constrained climate, full-lateral refracturing unlocks unrecovered reserves at a lower cost than newly drilled wells.

While the operator will have access to original surface equipment, and the original wellbore, the risk associated with getting that second bite of the cherry is dependent on embryonic technology development and availability. The use of expandable technology is the ideal example of new innovation that would not have been available a decade ago. Like any operation, the risk of doing what is well known but expensive compared to what is unknown and more cost-effective is the daily conundrum to support the evolution of effective, productive and sustainable drilling and completion.

A comprehensive study of the candidate history, including recent interventions and chemical treatments, should therefore be seriously considered while assessing the amount of preparation and cleanout needed (Figure 3).

Investing in R&D

Coretrax, which was formed in March 2020, following the merger with three oil and gas technology firms (Coretrax, Mohawk Energy and Churchill Drilling Tools) now has a portfolio of more than 50 technologies offered through three innovation platforms and plans to launch disruptive technologies to market this year. With a unified innovation offering designed to improve production performance and well intervention efficiencies, the business intends to reinvest more than 15% of revenues into R&D each year. ■

Editor's note: *CTO Scott Benzie joined Coretrax in 2019 following the integration with Mohawk Energy, which he founded in 2004. References for this article are available upon request.*

Diagnostic Methods for Reservoir Stimulation

Pressure-based maps and post-stimulation leak-off analysis identify optimal rock stimulation trends.

By David Lerohl, **Erica Coenen** and **Justin Mayorga**, Reveal Energy Services

As the oil and gas industry works to improve recoverable hydrocarbons, many innovations and advances are shared at conferences and others are shared among colleagues at operator companies. Sharing information, experiences and data ring true at the industry's core with updated knowledge and lessons learned. With this camaraderie, there is also friendly competition to strive to be the best. These conflicting virtues continually improve the industry through technological advances and new analytics practices. Some of these new practices include adding pressure-based monitoring to the traditional production analysis.

Production analysis has been regarded as the gold standard of comparison. While production is where revenue is accrued, many other diagnostics have recently become economically viable to help explain differences in stimulation effectiveness. Diagnostics must be cost-effective to render the return on invest-

Technology Overview

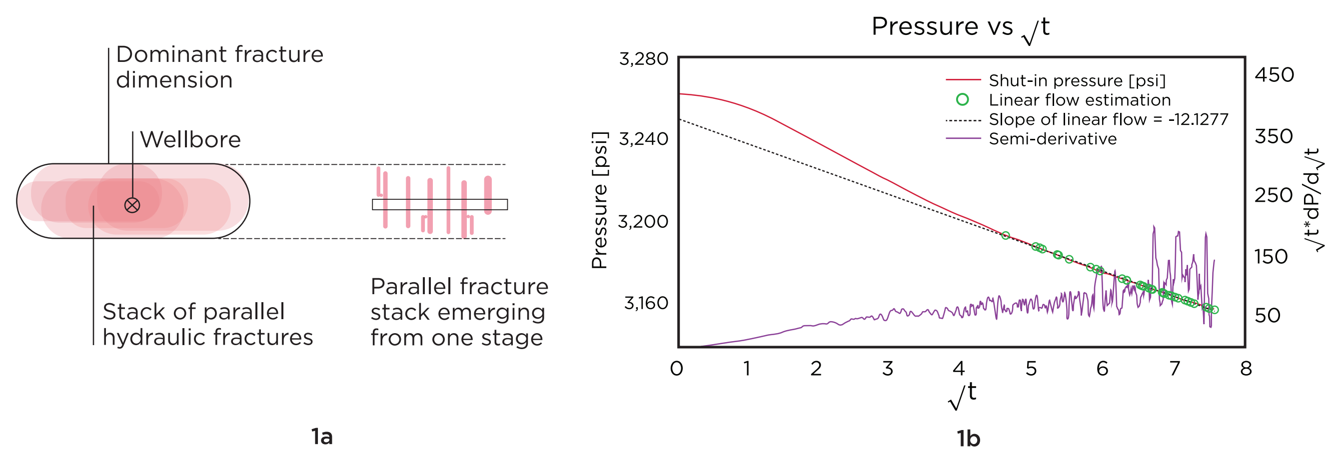

FIGURE 1. Figure 1a shows the dominant fracture dimensions in a stage with multiple fractures. Figure 1b depicts pressure decline from a treatment stage, highlighting when the pressure decline reaches linear flow. (Source: Reveal Energy Services)

ment (ROI) that operators seek in the drive to create more value from oil well completions.

Pressure monitoring has emerged as the most cost-effective diagnostic application because of the low cost of devices, minimal operational impacts and vast ability to analyze the data created. For the purposes of understanding more about this technology, Reveal Energy Services combined pressure-based fracture maps (PBFMs) and post-stimulation leak-off analysis to identify reservoir stimulation effectiveness for a full-field pressure monitoring application. Additionally, this method evaluated stimulation at each stage rather than having coarse aggregations at the well level, such as production analysis.

The two diagnostic methods were implemented on multiple pads across the Delaware Basin. These independent diagnostic applications monitored different areas of the reservoir and, when combined, provide a full-field evaluation of each monitored treatment stage. This article reviews the combination of the two methods with the treatment design variables to understand the completion trends that have resulted in optimal rock stimulation.

Pressure monitoring study

The two independent pressure monitoring techniques enabled the full-field stimulation evaluation. This study leverages datasets from multiple operators in a cooperative way. The operators agreed to aggregate and anonymize the data so there is an appropriate distribution to ensure valid conclusions.

The study was based in the Wolfcamp A Formation in the Delaware Basin. Stage-level data that typically include many more datapoints than well level data were considered. Several environmental factors must be similar for comparisons. Using data from similar geographical and geological perspectives helped to keep these environmental factors as close as possible.

The study proceeded as follows:

- First, an independent analysis was conducted for each pressure monitoring method.
- Second, a relative score was given for each method as low (1), mid (2) and high (3).
- Third, a proxy stimulated rock volume (SRV) was calculated by multiplying the scores from both methods.
- Finally, the average completion parameters were calculated (per foot of stage length) and compared to identify relevant distinctive trends.

Method 1 applied PBFMs, a Reveal Energy Services application in which a digital twin model renders the hydraulic extent for a dominant fracture in a given stage to determine fracture height, half-length and azimuth (Figure 1a). The pressure is monitored from an isolated stage in a nearby child, or infill, well.

> Diagnostics must be cost-effective to render the ROI that operators seek in the drive to create more value from oil well completions.

The location of the monitoring stage and treatment stages are inputs into the digital twin model, and the iterative solver updates the geometries so the modeled pressure response matches the observed pressure response. This is a far-field monitoring application because the stress extends through the reservoir to the monitor.

Method 2 applied post-stimulation leak-off analysis, which utilizes the pressure gauge on the treatment well to monitor the pressure decline after the pumps have been stopped for a period up to 1 hour. The rate of pressure decline is proportional to the amount of reservoir contact achieved during stimulation and, therefore, can be used in a stage to-stage comparison (Figure 1b). This monitoring is a near-field measurement because the pressure decline is directly measured from the treatment stage. The combination of the far-field and near-field monitoring provides a full-field evaluation for each completion stage. The full-field method improves the estimation of the SRV for a given stage.

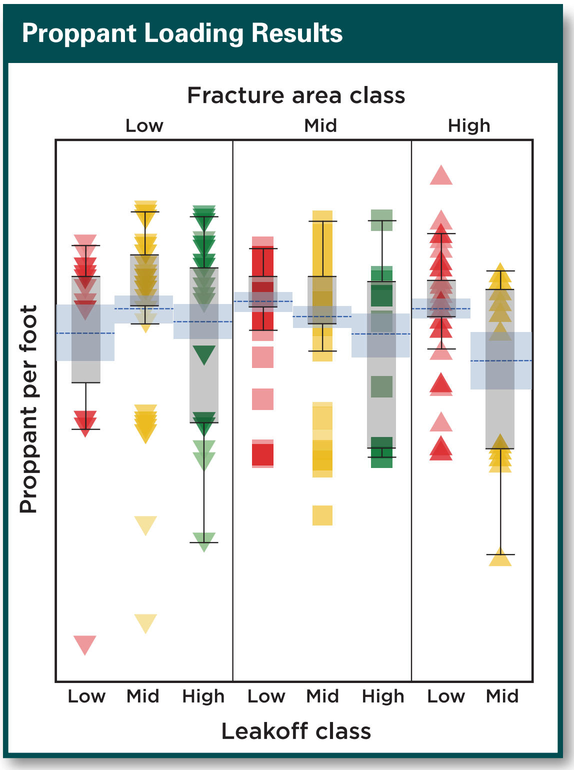

FIGURE 2. Stages grouped by independent methods indicate a lower proppant loading resulted in better SRV for a given area class. (Source: Reveal Energy Services)

Theoretical, Full-well SRV Calculation

$$Total\ SRV_{Theoretical} = \sum_{i}^{\#\,stages} Area_i * Length_i * \eta_i$$

Area is from the PBFM of the dominant fracture, the Length is the stage length and the efficiency factor is derived from the leak-off analysis. The SRV for a well is the summation of each stage's individual SRV contribution. A proxy to the SRV is used by multiplying the score from the post-stimulation leak-off analysis and the PBFM relative size with Area, and each stage is evaluated individually.

Observations and insights

This study arrived at three main insights. The stages with better SRV scores had lower proppant loading (pounds per foot) for a given fracture area. For example, of all the stages with a mid (2) rating

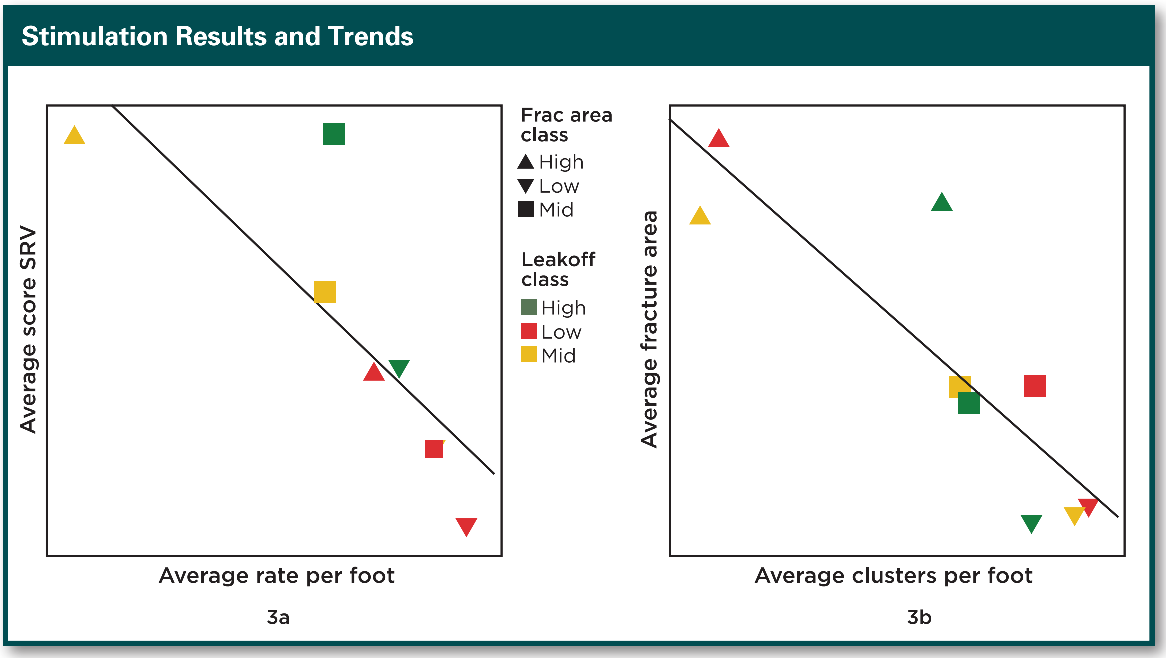

FIGURE 3. Figure 3a depicts cluster density that is inversely correlated with the dominant fracture area. Figure 3b shows the SRV proxy that is inversely correlated with the average rate pumped per foot. (Source: Reveal Energy Services)

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for fracture area in the PBFM calculation, the highest SRV group had the lowest proppant loading, and the lowest SRV group had the highest proppant loading (Figure 2).

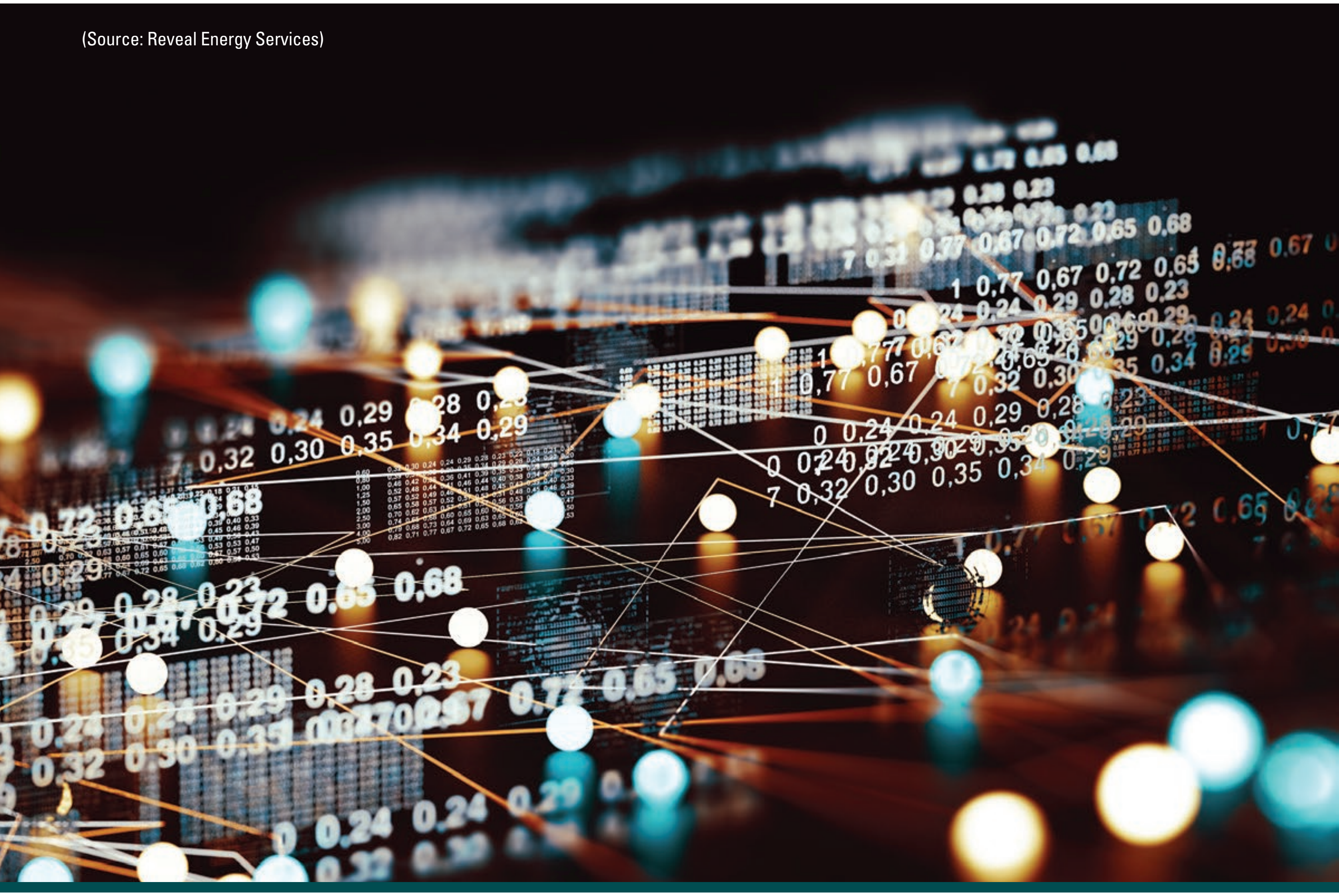
The average number of perforation clusters per foot was inversely correlated with the fracture area calculated from the PBFM (Figure 3a). This phenomenon has been studied with other diagnostics and production results where an increase of cluster density led to additional fracture initiation points and higher production. The result from this study indicated better fluid distribution for the high cluster densities.

The average pump rate per lateral foot was inversely correlated with the SRV calculation (Figure 3b). The highest SRV calculations had the lowest rate per foot. This study did not evaluate any form of limited entry so these findings are not applicable for those design studies. These findings are not applicable for any form of limited entry, which was not evaluated in this study.

Conclusion

With the combined analysis using PBFMs and post-stimulation leak-off analysis, the operators participating in this study learned that adding more clusters to a given stage while limiting the rate and proppant loading resulted in better SRV. Less proppant may provide enough conductivity for fracture flow, permitting the proppant to be carried farther into the fractures. The cluster density finding confirms that the higher number of perforations per foot can result in better fluid distribution as seen by the smaller dominant fracture area. These optimal rock stimulation trends, as identified in the study, reduced completion costs to improve ROI. ■

Editor's note: *This article is written from the URTeC-2020-2677-MS paper, "Combining Pressure-based Fracture Maps and Post-stimulation Leak-off Analysis Lead to Informed Unconventional Development." It has been reprinted here with permission of URTeC.*



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Novel Frac Power Meets Emission and Economic Objectives

Electric power generation for hydraulic fracturing operations gains significant advantages from deployment of the DuraPax™ Mobile Power System from NRG Technologies.

The novel technology uses reciprocating engines fired by wellsite natural gas to greatly lower methane emissions and reduce operating costs compared to diesel engines and turbine-powered generators. Modular and trailer-mounted, the DuraPax system is a scalable power generation solution that is easily and economically maintained with commonly available parts, fluids and mechanic skills.

NRG Technologies, an AFG Holdings company, recently field-tested this innovative technology alongside its DuraStim™ electric powered fracturing pump. The mobile power unit performed successfully and surpassed strict emission standards despite severe heat and varying power loads.

DuraPax generator technology delivers 3.6 MW of continuous duty power per trailer, while fully complying with EPA Clean Air Act standards. No additional exhaust stacks or catalysts are required. The power unit's NOX emissions are 40 to 50 times cleaner than blended fuel systems. At full load, it is 75 percent lower than EPA CO_2 emission requirements.

The robust power technology achieves emission compliance and high operational performance across a broad range of operating parameters, including temperature, altitude and humidity. Reliable, economic operation is ensured by continuous run times as high as 750 hours before preventive maintenance is due. Versatility is further enhanced by a low, 60 to 100 psi gas supply requirement, versus 535-psi turbine demands.

The mobile unit delivers power to the wellsite with minimal deployment and rig up time. Rugged and easily spotted on the wellsite pad, the DuraPax unit does not require foundational prep work or crane support. Full power is available only seconds after startup.

Generator output of 480v is easily transformed up or down to meet voltage requirements. Powerful enough for hydraulic fracturing, the versatile mobile unit also provides emissions-compliant economic electricity generation to run rigs and other wellsite operations, along with the option to sell back to the grid.

The DuraPax mobile power unit is easily integrated to supply power for conventional hydraulic fracturing spreads. It is also key to even greater advantages using NRG Technologies' advanced AMI controls and cloud service for remote operations and data acquisition, as well as the revolutionary DuraStim® hydraulic fracturing pump.

As detailed throughout this article, the DuraPax technology is field proven in hydraulic fracturing applications. Other well-suited applications where scalability matters include mining, petrochemical, general industrial and virtually anywhere remote power is critical. ■


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Next-generation Composite Frac Plug

An all-composite plug reduces the volume of composite material in the plug construction by 35%.

By Marty Coronado, The WellBoss Co.

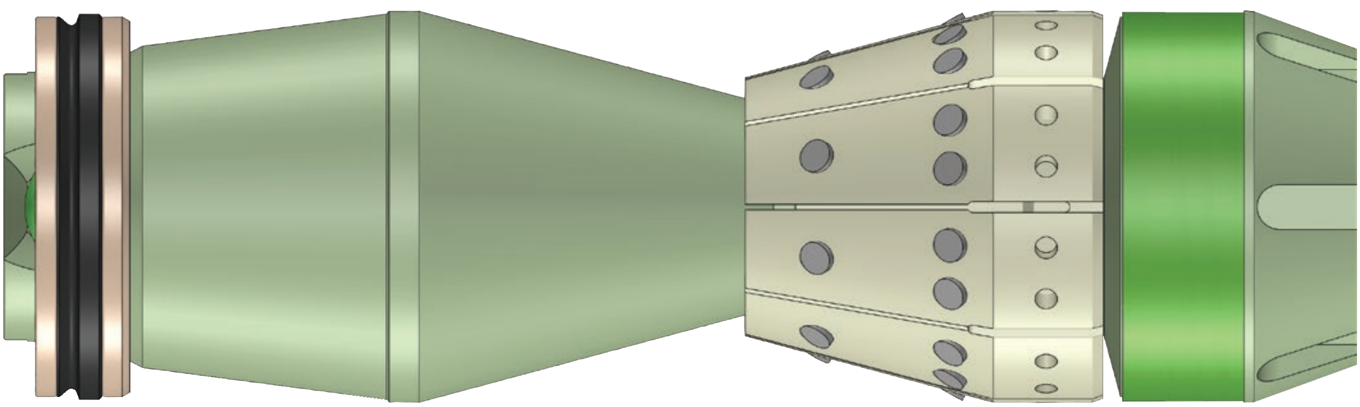
Frac plugs have been used in plug-and-perf operations for many years. Designs and materials have evolved over this period, with the latest models using essentially all-composite materials to allow better post-frac drill-up performance, in terms of both time required and size/volume of the remnants.

WellBoss' latest all-composite plug design provides the differential pressure rating required for fracturing operations but also better efficiency during drillout. This is achieved by dramatically shortening the length of the plug, thus reduced material volume and time required for the drill-out process, significantly reducing the amount of elastomer material used in the seal system and enhanced geometrical features.

A major factor in plug drill-out performance is the amount of material left in the hole after the drill-out operation. The latest WellBoss all-composite plug reduces the volume of composite material in the plug construction by 35%, compared to the previous plugs. Although the debris after drilling out is very small in size, it still needs to be flowed from the well during flowback operations, so reduced overall material volume is important. WellBoss uses glass-resin filament-wound composite materials that are tailored to specific downhole conditions, depending on service temperature, pressure requirements and fluid compatibility. The composite structure is engineered specifically for each component of the plug depending on the structural loading condition.

The new plug design eliminates the need for a traditional mandrel in which to mount the parts when running in the hole. The function of the mandrel has been incorporated into the setting tool and thus is removed from the well after the plug is set.

This concept allows simplification of the plug design into only four main components: lower guide assembly (which incorporates the pump-down mechanism), slip, cone assembly and seal ring. The slip design has also been geometrically optimized for best drill-out performance by removal of material where possible, while maintaining structural integrity. The amount of elastomer that constitutes the sealing



The all-new Boss Rezonite AC Gen II design uses less composite material and enhanced geometry for improved drill-out efficiency. (Source: The WellBoss Co.)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element is also potentially a major issue during the drill-out operation with traditional plugs, as larger pieces of rubber are flowed back to the surface and can plug surface equipment. Using a conventional design packing element, like what's used on many service and production packers, requires a substantial volume of elastomer. The new frac plug uses a different sealing system. The seal is based on a high-pressure bonded seal design used in production packer tieback assemblies. The elastomer seal is bonded into a thermoplastic carrier, which is expanded into sealing engagement with the casing during the setting operation. In comparison to earlier plug models, elastomer volume has been reduced by 97%. Using the expanding bonded seal design also eliminates the seal extrusion gap between the elastomer seal and the casing, which removes a possible failure mode.

Removing the mandrel shortens the plug and reduces material volume for improved drill-out efficiency.

Reduction in the number of anchoring buttons used to support the plug in the casing during high-pressure fracturing operations is a key design enhancement. The new design uses a single-slip system instead of the traditional dual-opposing design. The design of the anchoring buttons themselves have also been redesigned to minimize material volume but still maintain the anchoring strength required during high-pressure fracturing. During the drill-out operation, the newly designed buttons are much easier to fragment and come apart, thus leaving very fine pieces that can be more easily removed from the wellbore.

One design feature that was not changed is the highly efficient HELISEAL pump-down design, which has been perfected on WellBoss' original Boss Hog plugs. The HELISEAL is incorporated into the lower guide assembly. The bottom assembly mechanically connects to the running tool mandrel, which eliminates the possibility of pre-setting the plug while pumping in the hole. The plug can be run in either a ball-in-place or ball-drop configuration.

Field trials

The new plug was extensively tested in the laboratory during development to achieve all the characteristics that were required for the next-generation plug, as described above.

Once qualification testing was completed for the initial size, field trials were the next step in development. WellBoss partnered with a northeastern operator for the initial trials in 5½-inch, 20-lb casing.

As with all newly launched products, a limited field trial program was adopted that allowed the uppermost 10 stages in the well to be fractured using the new plug, with about 200-ft stage lengths between plugs. Although the plug was tested and qualified to its maximum rated service pressure (10,000 psi) and temperature (250 F) in the laboratory, the initial field trial well was in a 170 F bottomhole temperature reservoir. The initial field trial was conducted in June 2020.

The plugs were configured to set using a standard size 20 wireline setting tool and displaced into the well with pump rates between 12 to 16 bbl/min. All plugs were run with the ball in place. The initial WellBoss plug was set at 11,249-ft depth and required 97 bbl of water (two-thirds the amount of water to displace to setting depth compared to the plug used of the previous stage) to reach setting depth. This confirmed the efficiency of the flow-activated pumpdown feature in the plug. Fluid efficiencies remained high for the displacements of the remaining plugs on the later stages.

Once set, all plugs were pressure tested to 1,000 psi above wellhead pressure to confirm proper setting and sealing before perforating. Frac rates for all 10 stages were about 100 bbl/min, with about 9,000-psi surface pressure. Differential pressure across the plugs during the fracturing were between 6,200 psi and 6,300 psi. All fracs were completed with no issues.

Drillout of the plugs were completed about a month after the fracturing operation. The drillouts were performed using a snubbing unit and threaded pipe. The bottomhole assembly consisted of a 3.625-inch OD Bore Haug roller cone bit and 3.375-inch OD mud motor. Flow of 6½ bbl/min was used to power the motor coupled with 60-rpm rotary speed of the pipe, which resulted in a calculated 180-rpm bit speed. Weight on bit was held constant at about 3,000 lb.

The initial plug was drilled through in 5 minutes, with the remaining plugs removed with times between 7 and 19 minutes. This corresponded very well to drill-out times recorded in the laboratory during development. Returns looked good, with generally small pieces of composite and elastomer being flowed to surface. The operator was very pleased with the performance of the new plug in both the fracturing and drill-out operations. ■

Editor's note: *Marty Coronado is the vice president of R&D with The WellBoss Co.*

(Source: Sobrevolando Patagonia/Shutterstock.com)

Systems Instead of Silos for Bottom-line and Environmental Impact

Next-gen fracturing systems offer lower operating costs along with green benefits.

By Bryan Wagner, Weir Oil & Gas

Historically, the oil and gas industry has been slow to embrace change and modernization. It is understandable—commitment to safety is the bedrock of the industry. With workers exposed to a range of risks every day, safety is deeply embedded in the industry's culture. But with oil prices battered by a global pandemic, there is an undeniable mindset shift happening.

Instead of saying, "This is the way we've always done it," operators are asking, "How can we do this better?"

This new outlook is broadening minds to what is possible in the oil field. Those who embrace change and a systematic rather than siloed approach are poised to gain unheard of efficiencies.

Change avoidance has been seen as a way to reduce risk rather than a constraint. For too long,

the E&P industry continued to use manual processes that relied on people, pen and paper—even as the Internet of Things took the world by storm. The digital transformation finally took hold in the E&P space as the majors rushed to use new approaches to attack their cost basis for well development. Looking back, many of them are wondering why they took so long to make the leap.

> "Thinking in systems, not silos, enables us to see where the industry needs to go long before it gets there."
>
> *—Bryan Wagner, Weir Oil & Gas*

A similar pivot is underway in the oilfield services market as a whole and, more specifically, frac fleets. The pandemic has created a dramatic shift, causing service companies to focus intently on getting their next-generation 3.0 frac fleets built, tested and placed in the field to seize opportunities created by the evolving goals of the E&P companies.

Ensuring long-term viability

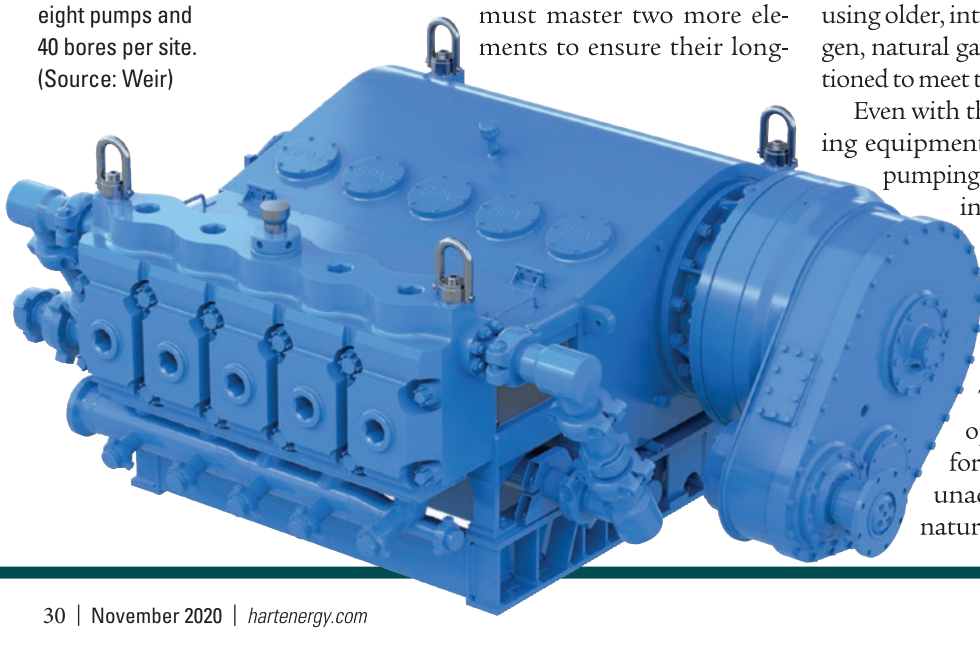
As pumping hours have increased to be nearly continuous duty, regularly clocking in 18 to 22 hours per day, the number of challenges operators face also has increased. Managing two long-held fundamental indicators—efficiency and nonproductive time—have typically been make-or-break factors for success and, ultimately, extended contracts. In the current and post-pandemic climate, companies must master two more elements to ensure their long-term viability: lower operating costs and reduced environmental impact.

While operating efficiencies can and do produce cost savings, those efficiencies have not touched on a significant cost driver—diesel fuel costs. E&P companies are driving the move to electric and natural gas power to lower their costs and drive sustainability compliance. As E&P companies reap significant savings by replacing diesel fuel with natural gas, pressure pumping companies investing in new 3.0 next-gen frac systems are uniquely positioned to win more long-term multi-year contracts from the ability to satisfy the sustainability and cost-reduction goals of E&Ps. Given these drivers, pressure pumpers that can burn natural gas for fuel will be the companies that survive the oil patch in the long term.

Reliance on natural gas for fuel opens an additional opportunity for pressure pumpers to have flexibility in the field while reducing costs. Natural gas allows operators to utilize e-frac or turbine direct drive given the horsepower requirements for natural gas. Operators utilizing natural gas are achieving efficiencies previously unattainable—such as a 60% maintenance cost reduction by reducing fleets from 20 pumps with 20 sets of expendables to just eight pumps. Removing diesel engines and transmissions saves an estimated $1.5 million per year on fleet maintenance—the second highest maintenance expenditure on location.

Beyond fuel and maintenance cost savings, natural gas eliminates the soot and noise pollution that is increasingly becoming regulatory targets. Operators unable to utilize natural gas are at risk of losing contracts due to the inability to comply with environmental regulations and operator requirements. Just like companies that could pump longer hours than those using older, intermittent equipment, those with next-gen, natural gas-powered fleets will be the ones positioned to meet the new criteria and remain competitive.

Even with the current saturation of legacy pumping equipment to the tune of 20 MMhp, pressure pumping companies are increasingly prioritizing investments in equipment that runs on natural gas. Operators that are unable to implement complete 3.0 next-gen systems today are bridging the gap with duel-fuel engines that burn 70% natural gas in their legacy footprints. This bridge approach, as well as fully optimized 3.0 frac systems, unlock transformative efficiencies that were previously unachievable due to the inability to use natural gas on a fracturing site.



Weir's SPM QEM5000 frac pump minimizes up-front capital investment as it can reduce a frac fleet from 20 conventional pumps and 100 bores per site to just eight pumps and 40 bores per site. (Source: Weir)

This transition to greater adoption of these next-gen hydraulic fracturing technologies demonstrates the maturity of the technology and the credibility it holds with E&P companies. Rather than piecing together existing components like fleets running today, pressure pumpers are leaning toward fully optimized systems, such as using the electric SPM QEM5000 Frac Pump, paired with true high-horsepower drive systems. Because fuel costs are among the top three opex on location, running on natural gas via e-frac or turbine direct drive can save up to 85% or $16 million per fleet per year.

High-efficiency e-frac or turbine drive technology is becoming fundamental to satisfy E&P goals for cost reduction and sustainability, which can mean the difference between winning or losing contracts. Broader, new drive technologies are creating system-centric, next-generation pumping platforms.

It is now more possible than ever for service providers to keep pace with E&P companies' requirements to remain competitive. As operators invest in natural gas and turbine-powered fleets, they are positioning themselves to not only pump more hours per day but to reduce fuel and maintenance expenditures, while also demonstrating a commitment to make a difference from an environmental perspective. The ability to meet the latest requirements enables pressure pumping companies to secure long-term, multi-year contracts.

The silver lining of today's climate is that it is transforming old mindsets to see and do things differently. The rate of change and acceptance of new technology is accelerating faster than ever in the pressure pumping market. Taking a systemwide approach is the only way to meet future demands. It is what is making 3.0 frac technologies a reality so E&Ps and operators can unlock a new source of savings. ■

Editor's note: *Bryan Wagner is the director of engineering and product management, pressure pumping, with Weir Oil & Gas.*

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Additional Information on Hydraulic Fracturing

For more details on hydraulic fracturing, consult the selected sources below.

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