HARTENERGY

Hydraulic Fracturing Techbook

2018

A supplement to E&P

Hydraulic Fracturing
The 2018 Techbook

A supplement to *E&P*

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Hart Energy's Techbook Series

The 2018 Hydraulic Fracturing Techbook is the 17th in a series of techbooks in which Hart Energy will provide comprehensive coverage of effective and emerging technologies in the oil and gas industry. Each techbook includes a market overview, a sample of key technology providers, case studies of field applications and exclusive analysis of industry trends relative to specific technologies.

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On the cover: Freedom Oilfield Services' Craig Prestidge at work on Comstock Resources' Hunter well in Caddo Parish, La. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)*

Hydraulic Fracturing

How much is old, how much is new and where to now?

By Michael Smith
Contributing Editor

Fracking–the new drilling process! Well, "hydraulic fracturing" is most certainly not new (circa 1947) and it is not a drilling process. For more than six decades fracturing has continuously increased in importance, an obvious result of the industry tackling bigger challenges with poorer quality formations. The evolution is apparent when comparing a modern treatment to the first fracturing job as depicted at right. The trend to poorer formations may have reached a zenith (both in terms of reservoir quality and importance of fracturing) in today's challenge of completing/producing nano-D "shale" (unconventional) formations. Particularly, given that many of the active unconventional developments are in "source rock," it would seem the end-of-the-line of poorer and poorer reservoir targets. However, one might start at the beginning, since there are interesting parallels with the early development of fracturing, and the development of fracturing practices in shales.

The first commercial fracture treatment was conducted on the Pickens No. 1 well in Oklahoma. The treatment used a total of 150 lb of sand, according to Halliburton's "Hydrafrac Treatment Report" of March 29, 1949. By all reports, the treatment was a great success; witness the rapid growth in the use of the new technology as treatments grew from zero to more than 3,000 per month over just four or five years (a paltry number compared to current operations to be sure). However, it might then be noted that circa 1970, about 1/3 of the 500,000 fracturing treatments performed were refractures, mostly pumped to place larger volumes of proppant.

There is another note from that 1949 treatment report: "Visual checks showed there was sufficient gel [viscosity] to hold the sand in suspension when dropped on the surface of the gelled crude. Since the gel rate had leveled off, 5 gal of water and 150 lb of sand was added to the gelled crude and pumped into the well."

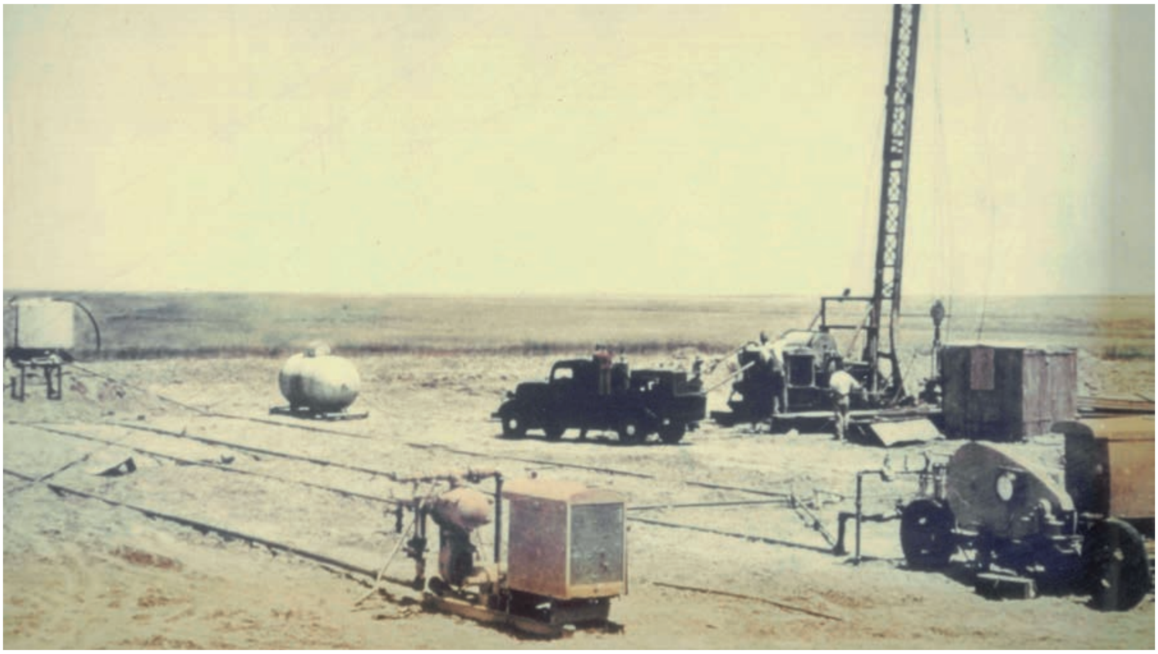
Note, there was no pad. The wellbore fluid, whatever it might have been, formed the pad to create/open the fracture. With 150 lb of proppant perhaps not much pad was needed. However, due to low permeability and very low fluid loss, many unconventional treatments have essentially returned to this practice. That being said, as soon as the pump rate is brought up to the desired level, proppant addition begins. The fluid in the well (generally water) forms the pad to open sufficient width to allow proppant entry into the fracture. Then, proppant settling transforms slurry to clean fluid, thus creating new pad to extend fracture length.

Finally, it might be noted that the first "water fractures" were pumped in the 1950s–the Dowell "River Fracs."

Fracturing then drifted along, with main emphasis being on surface/operations considerations. These included better pump trucks, larger volumes, blenders for mixing chemicals/proppant "on-the-fly," a slow change from oil- to water-based fluids, the switch from any sand to Ottawa sand, etc. Applications also slowly declined, primarily related to the decline of drilling activity due to Middle Eastern oil entering the market. However, using up the supply of existing well candidates also contributed.

A resurgence in hydraulic fracturing began in the late 1970s with development of a natural gas market in North America. This increased demand for gas (and tax incentives) brought "tight gas" into play. For the first time, hydraulic fracturing became a significant cost parameter, leading to the first significant advances in subsurface understanding of hydraulic fracturing. These included the first fracture models (including the first pseudo-3D and planar 3D models), understanding of proppant entry requirements into the fracture, theories on fracture propagation and height growth, understanding the importance of conductivity (leading to the development of high-strength proppant) and fracturing pressure analysis. Of course, surface developments

The Evolution of Fracturing



The first fracturing job is shown in this photo (top) from Amoco Production Research *(courtesy of C. Robert Fast);* (bottom) Cudd Energy Services recently performed a simultaneous zipper fracturing job on a multiwell pad. *(Photo courtesy of Cudd Energy Services)* also continued with high-strength proppants, cross-link fluids and foam fluids.

This all pretty much ended between 1981 and 1986 with the collapse of the industry led by OPEC's increased production. Hydraulic fracturing and fracturing technology entered a quiescent phase. One exception to this was in the area of fracture diagnostics with the early development of microseismic imaging and surface tiltmeter analysis. Major dividends from this, however, were not realized for another 15 years with their use in the unconventional reservoirs.

After surges in the 1950s and 1970s, the third major surge of fracturing came about in the 2000s from the confluence of several events. These included the return of water fracturing, an increasing price for gas, importation of the water fracturing idea from the East Texas Cotton Valley tight gas play to the Barnett Shale in central Texas and the improvements in horizontal drilling.

Working outward from one area of commercial production from the Barnett, Mitchell Energy explored it for many years, drilling vertical wells and performing massive fracture treatments using "conventional" ideas (i.e., viscous fluids). This was largely unsuccessful, with Mitchell at one point writing in a technical publication "natural fractures are detrimental to production in the Barnett Shale." This was undoubtedly due to gel plugging of natural fractures. If there was minimal natural fracturing, then the fracture treatment created a long fracture in a nano-D formation, yielding some production. In the presence of natural fractures, the resultant high fluid loss led to a very short hydraulic fracture, with gel then destroying any natural fracture permeability resulting in no production. This changed with the importation of the slickwater fracturing idea from the East Texas Cotton Valley tight gas, leading to a boom in Barnett production beginning about 2002. It is noteworthy, however, that the initial adoption of slickwater fracturing was seen as a cost-reduction measure.

Also, minimum proppant was used in what Mitchell Energy referred to as "light sand fractures." As Mitchell moved south from the "core area," high growth downward into the wet Ellenberger limestone became a serious impediment. This led to trials with horizontal wells. The use of horizontal wells was then expanded by Devon and, literally, the boom was on. Subsequently, with further increases in natural gas prices, the technology moved to other areas, principally the Eagle Ford in South Texas, and the Haynesville Shale in Louisiana. Barnett production then began to peak circa 2010, coinciding with a falling natural gas price, and this general trend was also seen in other shale gas areas. Simultaneously, an increasing trend in oil prices led to continuing activity in shale oil (e.g., Wolfcamp in the Permian Basin and Merrimack in central Oklahoma). Proppant mass use remained relatively small; in today's parlance proppant usage was on the order of a few hundred pounds per foot of lateral.

This use of "minimal" proppant continued through many years of horizontal, multiple fractured shale wells. A full decade following the initial Barnett gas shale boom, proppant usage began to increase exponentially. Small fracture treatments with very little proppant eventually followed with much larger treatments with exponentially increasing proppant volumes, eventually leading to thousands of refracture candidate wells.

The increased success with the larger treatments led to a continuing expansion of fracturing (despite recent setbacks). Again, the path forward focused on operational considerations and logistics–with the incredible industrial engineering achievements leading to efficiencies unthinkable even a short time ago. Treatment design then became a subject for trial and error, and statistical analysis through the use of Big Data. This brings us to the present, with more than 80% of activity concentrated in a few hotspot areas (Permian Basin, Marcellus Formation, Cana Woodford and Williston Basin) where current practices allow profitable operations at $50/bbl.

What next?

If history is an indicator, it should once again be time to focus on the subsurface and the daunting geotechnical issues to be faced and solved. First among these is probably field/reservoir development with development drilling having to consider both lateral well placements and vertical well placements. Hopefully this can extend operations to other "not-so-hotspot" areas. ■

References available.

About the author: Prior to joining Amoco Production Research, Mike Smith received a Ph.D. in mechanical engineering (rock mechanics) from Rice University. Amoco's main interest at the time was natural gas, with hydraulic fracturing research (tight gas, coalbed gas, shale gas, etc.) being critical. Subsequently Smith formed NSI Technologies (now part of Premier Oilfield Group), fracturing wells in more than 30 countries. Along the way he received the SPE Lester C. Uren Award for technical contributions prior to age 35, and, in 2018, was named by the SPE as a "Legend of Hydraulic Fracturing."

Charge of the Fracturing Brigade

The industry's top hydraulic fracturing players mobilize to provide the products and services necessary to optimize well stimulation operations.

By Ariana Hurtado
Associate Managing Editor

The U.S. hydraulic fracturing market is set to reach $13.91 billion by 2025, "owing to the rise in the oil and gas exploration and extraction activities in the country over the forecast period," according to a recent *ResearchandMarkets.com* report. "The hydraulic fracturing segment dominated the market in 2017 and is expected to maintain its dominant position over the forecast period owing to the use of hydraulic fracturing and horizontal drilling activities in conventional and unconventional reservoirs."

In the following section, Hart Energy profiles some of the most active hydraulic fracturing companies and briefly reviews the products and services they offer.

Key Players

Working with a large operator in West Texas, AFGlobal delivered a fracturing equipment spread to drive improved operational efficiencies and a lower cost of ownership. *(Photo courtesy of AFGlobal)*

AFGlobal

AFGlobal is a technology and original equipment manufacturing specialist that provides engineered solutions for complex challenges across a broad scope of applications and industries.

The company's pressure pumping products and services include pumps, hydration units, data vans, blenders and manifolds as well as proprietary smart technologies for hydraulic fracturing automation, control and data analytics.

The company's DuraStim system, released in late 2017, is a linear injection pump that is designed to enhance hydraulic fracturing performance and efficiency for shale completions, according to the company. Its 140-bbl/min blender provides shale operations with a Tier 4 solution for reliable, high-rate slurry mixing.

AFGlobal's advanced managed-pressure drilling (MPD) systems are the product of comprehensive capabilities in project engineering, integrated equipment and sophisticated controls. Powerful insights into MPD technologies and methods are being achieved through simulations enabled by the company's unique new test rig, the company said. AFGlobal offers high-performance land-based gas compression systems and integrated subsea connectors and control systems.

In July 2017 the company acquired Advanced Measurement Inc., a provider of automation, controls and data management systems.

In addition, in October 2017 the company acquired the Axon pressure pump technology and product line from Amkin Technologies LLC, a privately held oilfield equipment and technology developer, according to company press releases.

Archer

Archer is a global oil services company that operates in 40 locations across 19 countries providing drilling, well integrity and intervention, plug and abandonment, decommissioning and consulting services.

Archer drilling teams secure the production on more than 47 offshore platforms and operate more than 81 mobile land rigs.

The company's drilling and workover services include platform drilling, land drilling, directional drilling, drillbits, modular rigs, fluids, engineering and equipment rentals as well as a select range of well delivery support services and products.

Archer "specializes in horizontal and vertical wellbore stimulation utilizing high-pressure, high-rate hydraulic fracturing services, cased-hole wireline, pressurized fluid pumping, coiled tubing and rig assist snubbing," the company stated on its website.

Additionally, AWC Frac Valves, part of Archer, manufactures and provides high-integrity gate valves for hydraulic fracturing.

In April Archer released its new VIVID acoustic listening platform, a highly sensitive, acoustic technology that detects, investigates and locates leaks in real time, verifies cement barrier seals and characterizes downhole events with unparalleled precision, according to a company press release.

ArrMaz

Founded in 1967, ArrMaz provides specialty chemicals across multiple industries in more than 70 countries worldwide. For the oil and gas industry, the company offers SandTec, a silica dust control frack sand coating technology for hydraulic fracturing operations.

When applied to frack sand, SandTec reduces respirable crystalline silica dust to below The Occupational Safety and Health Administration's permissible exposure limit and action level, according to ArrMaz. "Unlike mechanical and PPE [personal protective equipment] systems, SandTec minimizes silica dust generation from the sand plant to the wellhead, spanning the entire hydraulic fracturing supply chain," according to the company. The product does not require drying or curing, is compatible with a variety of frack fluids and will not adversely affect well performance, the company said.

In addition, SandTec does not require any setup, breakdown or maintenance of mechanical dust abatement systems and does not occupy valuable real estate at the fracturing site. The technology reduces site dust that can adversely affect equipment and is environmentally friendly.

Baker Hughes, a GE company

The multistage fracturing portfolio from Baker Hughes, a GE company (BHGE), includes completion tools, flow assurance chemistry, proppant technology, fracturing fluid systems and 24/7 real-time production monitoring services.

The company's SPECTRE plug contains no metal inserts or ceramic buttons and completely disintegrates downhole after fracturing, eliminating post-fracture intervention and providing faster, easier wellbore cleanup, according to the company. BHGE continues to expand the temperature range of the disintegrating metallurgy to enable reliable, predictable performance at bottomhole temperatures as low as 38 C (100 F).

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-Frac Manager
“We eliminated the majority of our plug costs”
-Mid-Con Operator
“Our production increased substantially”
-Woodford Producer
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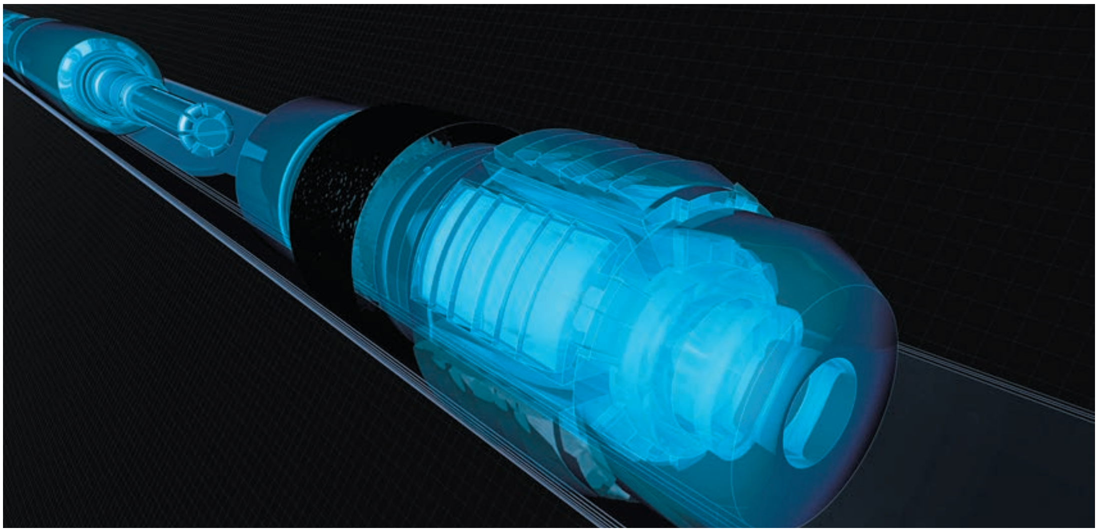


The SPECTRE plug disintegrates fully after fracturing, eliminating risks associated with metal slips or ceramic buttons left downhole, according to the company. *(Image courtesy of Baker Hughes, a GE company)*

For wells located in formations where water/gas breakthrough is a risk, the OptiStriker straddle packer system enables precise fracture height control through targeted stimulation and real-time downhole diagnostics. The system also provides fast screenout recovery to minimize nonproductive time.

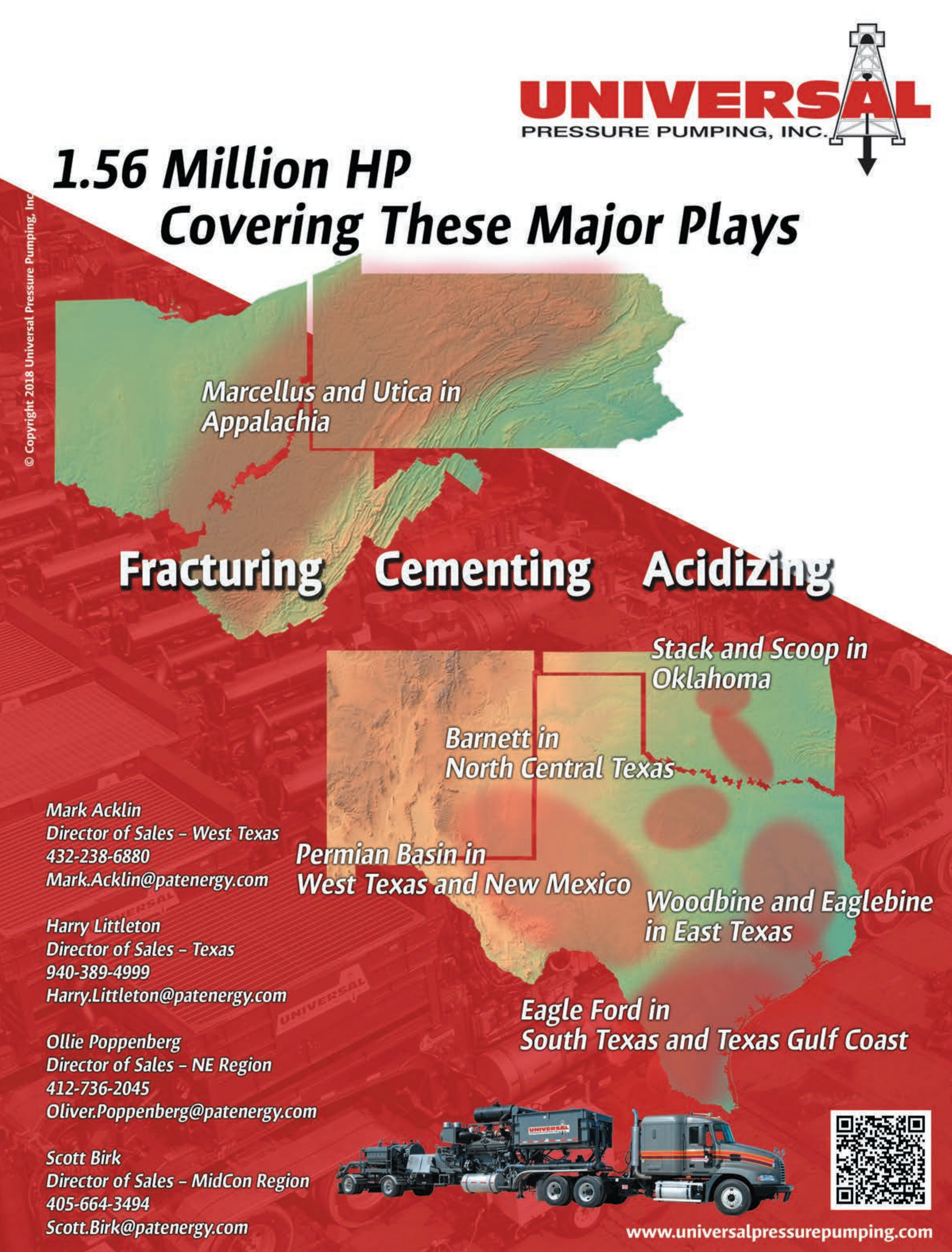
BHGE also offers Sorb and Sorb Ultra solid inhibitors to inhibit scale, paraffin, asphaltenes and salt, in addition to controlling bacteria and corrosion. BHGE's proppant technology is engineered to provide consistent fracture support and long-term conductivity.

The company also offers a complete acid fracturing service as well as an enhanced conductivity fracturing service, which is designed to create tailored proppant pillars for long-term fracture support. Additionally, the company's hydraulic fracturing software tools allow users to fully visualize complex fracture geometries and distributions.

BJ Services

BJ Services is the largest North American-focused, pure-play pressure pumping services provider. The company operates field locations serving all major North American oil and natural gas shale basins.

This redesigned blender from BJ Services is part of the company's fracturing equipment. *(Image courtesy of BJ Services)*



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One of the latest additions to the company's fracturing fluids offering is its ThinFrac MP friction reducer, which enhances proppant transport. This co-polymer provides rapid hydration, developing instantaneous viscosity, reducing pipe friction pressure and delivering the proppant when and where it is needed, according to the company. "The key breakthrough of the polymer is the precision breaking at engineered oxidizable linkages along its backbone, allowing for a clean, efficient break with little to no formation or proppant pack damage," according to the company.

In addition, to ensure efficient wellsite delivery, the company has redesigned its blender to handle the increasing demands of longer laterals and higher volumes and support more advanced health and safety requirements. The redesign specifically addresses and eliminates problematic components throughout the mixing system. For example, the simplified piping minimizes erosion and allows more efficient flow, the company said. Additionally, the blender tub has been engineered for ease of access to enable planned maintenance at the company's manufacturing centers and onsite routine component cleaning. The new mixing system pumped more than 215 MMlb of sand without experiencing any mixing system downtime over six months in the Permian Basin.

C&J Energy Services

C&J Energy Services offers a vertically integrated suite of services involved across the life cycle of the well. Services include fracturing, wireline, coiled tubing, cementing, rig services, fluids management services and other special wellsite services. In addition to conventional operations, the company's services are designed to handle technically demanding reservoir challenges.

C&J's conventional and unconventional reservoir experience, combined with in-house research and technology capabilities, enables the company to offer a range of stimulation and restimulation techniques. These include a proprietary LateralScience engineered completion method as well as other reservoir stimulation services designed to help regain production and increase well recovery.

One of C&J's fracturing fleets operates in West Texas. *(Photo courtesy of C&J Energy Services)*

The LateralScience method leverages commonly available drilling measurements to help guide the placement of perforation clusters, leading to uniform fracture treatment and increased production within each fracture stage, according to the company.

The company's recently introduced GameChanger perforating system used in its wireline operations was designed with no ports and has no wires running from gun to gun. This configuration was designed to improve the reliability and efficiency of its services by significantly reducing misruns caused by problems within the perforating gun, the company said.

In November 2017 C&J completed its acquisition of O-Tex Holdings Inc. and its operating subsidiaries, including O-Tex Pumping LLC, for approximately $132.5 million, according to a press release. "O-Tex is the fourth largest provider of oilfield cementing services in the U.S. based on internal data and industry sources," the release stated. "O-Tex specializes in both primary and secondary downhole specialty cementing services in most major U.S. shale plays with eight field offices, eight lab facilities and one of the youngest fleets in the industry."

Also in the fourth quarter of last year, C&J divested its Canadian rig services business to CWC Energy Services Corp., according to a November 2017 press release. The transaction included the company's Canadian fleet of 75 workover rigs, 13 swabbing rigs and the real estate associated with six operating facilities throughout Western Canada.

Calfrac Well Services has hydraulic fracturing operations in North Dakota in the Bakken (see write-up on page 16). *(Photo courtesy of Calfrac Well Services)*

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Calfrac Well Services

Calfrac Well Services is an independent provider of specialized oilfield services, including hydraulic fracturing, coiled tubing, cementing and other well stimulation services. The company offers a non-damaging synthetic friction reducer that exhibits support characteristics for higher proppant concentrations. The company also offers diverter technology, slickwater solutions for fresh and high total dissolved solids brine applications and all traditional industry applications of gel-based, crosslink and energized fracturing needs. Treatment types and additives (such as surfactants, biocides and diverters) can be customized for operational, treatment and production objectives.

Calfrac operates in the major basins in the U.S. including in the Bakken, Rockies, Niobrara, Eagle Ford, Permian, Marcellus and Utica. Operations in Canada service the Viking, Cardium, Deep Basin, Montney and Duvernay.

Calfrac's HSE program includes procedures to ensure it meets or exceeds all applicable HSE regulations. The company develops and tests technologies that are designed to boost efficiency, reduce water consumption and minimize risk to the environment, according to the company.

Additionally, regional laboratories are positioned in locations to ensure direct support is available to customers and at the well site.

Calfrac's supply chain, logistics optimization and asset management strategy includes access to sand mines and terminals, long-term leases on private rail cars, barges and trucks, access to unit train facilities and third-party transloads as well as field storage for last-mile product management.

CARBO

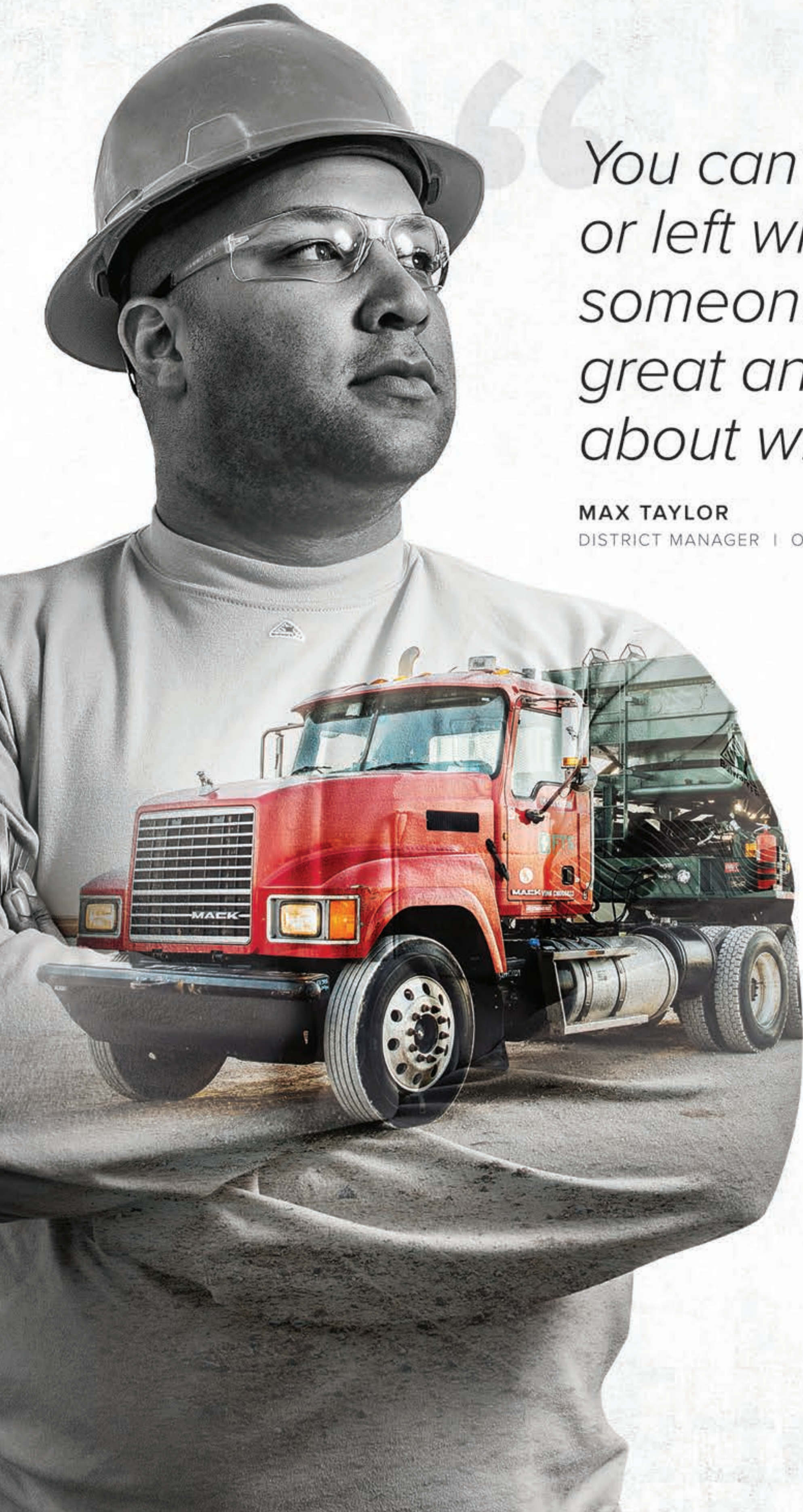
CARBO is a technology and services provider that focuses on integrating technologies to provide engineered solutions that help E&P operators design, build and optimize a fracture. The company's proppants include ultraconductive ceramic proppant, high-transport proppant, microproppant, ceramic proppant, resin-coated proppant and sand proppant. CARBO also offers proppant-delivered production assurance, flow enhancement and fracture evaluation as well as biodegradable diversion ball sealers and proppant pack consolidation technology. The company also provides fracture software and fracture consulting services.

In 2017 CARBO designed a technology that improves the ability to detect the location of proppants in the reservoir. "QUANTUM quantified propped reservoir volume imaging offers far-field fracture imaging that shows actual proppant location," according to an article that appeared in *E&P* magazine in July 2017, at which time the method was still in the field trial phase. "The program also assists in understanding well drainage and spacing, stage and perforation cluster spacing, vertical fracture coverage and the impact of fracture design changes."

Covia Holdings Corp.

Covia is the result of the June merger between Unimin Corp. and Fairmount Santrol. Covia, a minerals and materials solutions provider, has 36 million tons of proppant capacity, more than 50 million tons of total capacity and more than 1.4 billion of reserves. The company's products range from raw minerals to highly engineered products like resins, custom blends, resin-coated sands, Propel SSP and DustShield.

Propel SSP proppant transport technology "props open the fracture from wellbore to tip, maximizing the fracture surface area to increase hydrocarbon production," according to the company. The technology is designed to "eliminate additives, including guar, crosslinkers and friction reducers for increased hydraulic fracturing efficiency using a simplified fluid system."



In addition, DustShield treated sand is northern white fracturing sand with dust suppression technology and an operationally transparent engineering control that reduces worker exposure to respirable crystalline silica, according to the company.

Cudd Energy Services

Cudd Energy Services (CES) operates in more than 60 global markets, including the major shales across North America. The company provides customized completion, production and well intervention services for onshore and offshore operations including stimulation, coiled tubing (CT) and e-coil, coil drilling technologies, hydraulic workover, slickline and braided line, electric line, industrial nitrogen, cementing water management, well control and special services.

CES provides a variety of stimulation services including hydraulic fracturing and acidizing in conventional and unconventional oil and gas reservoirs. The company's hydraulic fracturing services range from single-stage fractures to complex multistage, horizontal fractures. Each operation includes prejob analysis of the well, real-time monitoring (with the FracLink application) and a reporting system at the end of the job to meet state reporting requirements.

The company's FracLink software package contains four fully integrated modules for fracture design, fracture analysis, economic optimization and reservoir performance, according to the company's website.

CES applications of hydraulic fracturing stimulation treatments include slick water, linear gel, crosslinked gel, CO_2 foam and nitrogen foam. The company designs custom-blended acidizing treatments to increase well productivity and assist in well cleanout applications. Acidizing applications include matrix, CT and remedial.

In addition, CES offers additives and equipment that are custom-engineered for stimulations services. The company's stimulation equipment fleet includes about 935,000 hhp. Individual units can deliver up to 2,250 hhp and are capable of operating pressures up to 13,250 psi.

DistributionNOW

DistributionNOW (DNOW) is a global distributor and solutions provider to the energy and industrial sectors. With more than 285 locations across 20-plus countries, the company offers commodity and engineered products as well as services and turnkey solutions for onshore and offshore drilling and E&P.

DNOW's offerings include pipehandling equipment, solids control equipment, instrumentation,

The puraDYN oil bypass filtration system was installed in a fracturing unit. DistributionNOW holds an exclusive global distributorship. *(Photo courtesy of Puradyn Filter Technologies Inc.)*

chemicals, industrial and janitorial supplies, hand and power tools, safety supplies and personal protective equipment, electrical products, and industrial paints and coatings.

E&P products include line pipe, valves and actuation, fittings and flanges, gaskets and fasteners, artificial lift systems, pumps and compressors, belts and sheaves, lubricants, adhesives and other consumables as well as modular equipment such as lease automatic custody transfer units, vapor recovery units, separator packages, heaters/treaters, American Society of Mechanical Engineers vessels, water transfer, water disposal and waterflood.

DNOW also offers supply chain solutions such as procurement, inventory and warehouse management, logistics, project management and performance metrics reporting.

DynaEnergetics

DynaEnergetics provides perforating products and systems for use in conventional and unconventional wells worldwide. The business operates a global network of manufacturing facilities and designs, produces and qualifies all of its equipment and accessories in-house.


TUFF
BREED
When the going
gets
tough

An R&D technician ensures accurate measurements of a shaped charge interior. *(Photo courtesy of DynaEnergetics)*

Key product offerings include DynaSelect, the first fully integrated, intrinsically safe switch-detonator combination, and DynaStage, the first factory-assembled, performance-assured perforating system, according to the company. DynaStage is custom-assembled to address customer requirements for charges and phasing and is available in three diameters: 3⅛ in., 3⅜ in. and 2¾ in. "The DynaStage product line is compatible with all primary well configurations in use by North America's onshore, unconventional oil and gas industry," according to a company press release.

DynaSelect and DynaStage are controlled via the Infinity Firing Panel, which "allows for faster switch testing and operation with instant on-command initiation," a company press release stated. "The Infinity Panel allows the operator to test, initiate and skip stages as desired."

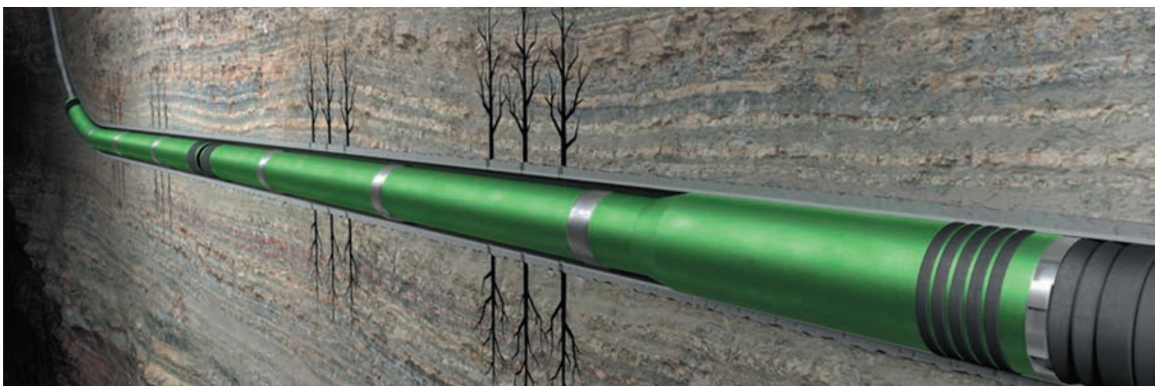
DynaEnergetics also offers high-performance shaped charges designed to address a wide range of applications and downhole conditions.

Enventure

Enventure Global Technology Inc. is a provider of solid expandable solutions for the energy industry with offices worldwide.

"Enventure's SET and ESeal technology radially enlarges proprietary tubulars through a cold-drawing process using a downhole cone-driven expansion assembly," the company stated on its website. "SET and ESeal systems have been expanded through window exits and milled sections, modified for corrosive well installation, installed in deviated and horizontal wells, and have proven to be advantageous when coupled with other enabling technologies such as surface stack drilling, intelligent completion tools and multilaterals."

In May the company released the next generation ESeal 3.0 solid expandable refracturing liner to "provide operators more options when selecting among mechanical zonal isolation techniques," according to a company press release.



The ESeal 3.0 RF Liner is enhanced to provide the industry's highest strength and temperature ratings that will mechanically isolate old perforations, with the largest ID possible, providing more flow and more power to reservoirs during refracturing. *(Image courtesy of Enventure)*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Flotek Industries Inc.

Flotek's Energy Chemistry Technologies segment develops and delivers prescriptive chemistry technologies to oil and gas operators and service companies. Flotek chemistry technologies and reservoir application platforms enable the delivery of chemistries that are designed to add value to assets. Flotek's total fluids systems include custom technologies and conventional chemistries that are designed to maximize recovery in both new and mature fields and to address every challenge in the life cycle of the reservoir and field from drilling, cementing, completion and stimulation activity.

Flotek's line of chemistry technology products, Complex nano-Fluid, is made from naturally sustainable and nontoxic citrus oil and has helped improve well performance, productivity and financial returns of E&P companies, according to the company.

In April Flotek released MicroSolv, its new line of microemulsion technologies that are a blend of solvents and surfactants. The chemistries are formulated to enhance performance by lowering interfacial tension, mitigating water blockages, reducing surface tension, aiding flowback of water-based fracturing fluids, improving cleanup and reducing formation damage created by phase trapping, according to a company press release.

FTS International

FTS International (FTSI) is one of the largest providers of hydraulic fracturing services in North America based on both active and total horsepower of its equipment, according to the company. The company provides high-pressure hydraulic fracturing and wireline services with an expertise in stimulating production of oil and natural gas from wells in shale and other unconventional formations.

FTSI also is a vertically integrated manufacturer. The company assembled its 32 fleets in-house; continues to manufacture many of the components used by its fleets, including hydraulic pumps, fluid-ends and other consumables; and is manufacturing two newbuild fleets. In addition, the company performs substantially all of its own maintenance, repair and servicing of its hydraulic fracturing fleet.

For the past three years, the company's total recordable incident rate was less than half of the industry average, according to FTSI. Recent examples of the company's initiatives aimed at improving HSE conditions include deploying dual fuel engines that can run on both natural gas and diesel fuel; electronic pressure relief systems; spill prevention and containment solutions; dust control mitigation; sensor-driven, remote monitoring of working equipment; and containerized proppant delivery solutions.

Flotek delivers its Complex nano-Fluid chemistry to enhance production and cash flow for an operator with acreage in the Austin Chalk. *(Photo courtesy of Flotek)*

Gardner Denver

Gardner Denver offers engineering and support for petroleum and industrial pumps in the global upstream oil and gas market.

Specifically designed to extend equipment life, Gardner Denver's Redline Packing is designed to cut maintenance time in half. *(Image courtesy of ELL Creative)*

The company designs, manufactures and tests a range of small and light pumps for the oil and gas industry. Gardner Denver also offers drilling pumps, fluid ends, liquid ring vacuum pumps, compressors and more.

In the first quarter of 2018, the company announced the launch of its consumables brand, the Redline series. "The first consumable introduced to the market was Redline Packing, the critical seal system in the heart of the frack pump, creating a barrier between frack fluid and the environment," the company said.

In June 2017 Gardner Denver acquired LeROI Compressors, and in February 2018 the company acquired Runtech.

Halliburton

Halliburton stimulation technologies are designed for fracturing, pinpoint stimulation, acidizing/near-wellbore cleanout and conductivity endurance. Halliburton focuses on both improving surface efficiency aspects of hydraulic stimulation as well as developing solutions to optimize asset productivity through subsurface evaluation and engineered fracturing designs.

The company's MicroScout service is designed to increase stimulated reservoir volume by "connecting the complex fracture network to the primary fractures" and its EZ-Stim service is designed to "improve efficiency of hybrid fracturing treatments and stimulating long horizontals," according to Halliburton's website.

The company's 2,000-hhp Q10 XLE pumping unit was designed to reduce noise emissions on location, decrease nonproductive time and perform in challenging conditions, according to a product data sheet. "Mono-block fluid end handles the demanding duty cycle required for shale fracturing," the data sheet stated. "Testing and modeling have indicated that, under identical conditions, the Q10 XLE pump provides over 20 times the fluid end life of legacy pumps."

In addition, Halliburton acquired Summit ESP in July 2017.

Hexion

Hexion creates advanced chemistries to improve well economics from drilling through production. The company's portfolio includes drilling and cementing additives, proppant enhancement additives, resin-coated proppants and production chemicals. Hexion's offering includes a variety of resin-coated proppants, covering curable sands, curable ceramics and precured sands along with consolidation aids and silica dust suppressants.

"We were the first to develop mobile resin-coating technology, offering efficient in-basin manufacturing in any location," the company said. "This new solution offers optimum logistics to the well site, even internationally."

Hexion's resin-coated proppants provide features such as the AquaBond proppants' ability to reduce the production of formation water. *(Image courtesy of Hexion)*

Hi-Crush Partners

Hi-Crush is a provider of proppant and logistics solutions to the North American oil and gas industry. The company's production facilities are capable of producing 13.4 million tons per year of high-quality monocrystalline sand, a specialized mineral used as a proppant during the well completion process. The company's production facilities' direct access to major U.S. railroads enhance its delivery capabilities into consuming basins, while the

company's owned and operated in-basin terminals and in-basin production facility position it within close proximity to significant activity in all major oil and gas basins for advantageous truck transportation, according to the company.

Hi-Crush's integrated distribution system, with its PropStream logistics solution, delivers proppant the last mile into the blender, providing operators security of supply from the mine to the well site, the company said.

Keane Group

According to the company, Keane is one of the largest pure-play providers of integrated well completion services in the U.S. The company focuses on complex, technically demanding completion solutions and its primary service offerings include hydraulic fracturing, wireline perforation and logging, engineered solutions and cementing, among other services. The company has locations in the Permian Basin, Marcellus-Utica Shale, Bakken Formation and Scoop/Stack area.

Keane's hydraulic fracturing equipment includes about 1.2 million hydraulic horsepower, high-rate blenders, nitrogen units and high-pressure capability. Operations are backed by an extensive logistics organization that has national sand contracts, 1,200 owned rail cars and a fleet of more than 120 sand haulers.

Wireline services are offered with specialties in plug-and-perf operations, mechanical services, radial cement bond logging and casing image calipers. Keane provides its own cranes, pressure control equipment up to 15,000 psi and greaseless wireline capability.

Keane's technical team designs well-specific stimulation and cleanout fluid technology at the Engineering & Technology Center in The Woodlands, Texas. This laboratory is equipped for comprehensive pre- and post-job fluid analysis, along with fluid, proppant, cement, corrosion and microbial testing. District operations are additionally supported by a network of laboratories located in every major basin.

Keane has 24 fit-for-purpose units for cementing services and pressure pumping for toe prep and other pumping services.

Kerr Pumps

Kerr Pumps manufactures fracturing fluid ends and pumps.

Among the company's products are its Frac One CONNECT fluid end as well as its Transfer The Wear, which transfers the wear to a sacrificial consumable and away from the fluid end. "All of this is in an effort to increase the operating life of fluid ends and decrease expense and downtime in the field," the company said.

Kerr Pumps has more than 200 CNC machines under one roof. The facility includes live tooling lathes, five-axis boring mills, vertical machining centers and horizontal machining centers. In addition, the company has a full service fabrication shop that is equipped to weld up missile trailers and pumping skids such as reversing and closing units. The company provides maintenance, complete overhauls and advanced diagnostics for pumps and fluid ends. "As the largest machining factory in Oklahoma, everything at Kerr Pumps is designed, engineered, machined, assembled and tested under one roof," the company said.

Liberty Oilfield Services LLC

Liberty Oilfield Services provides specialized stimulation services, hydraulic fracturing and engineering services. Liberty has field offices in Henderson, Colo. (Denver-Julesburg Basin), Gillette, Wyo. (Powder River Basin), Williston, N.D. (Williston Basin), Odessa, Texas (Permian Basin) and Cibolo, Texas (South Texas/Eagle Ford). Liberty has a hydraulic fracturing capacity of 560,000 hhp.

The company's services include completions and production evaluations using Liberty databases for U.S. liquid-rich basins in conjunction with detailed multivariate analysis.

Liberty also assists in the coordination and evaluation of laboratory and field tests required to support the stimulation program, performs analysis of diagnostic data to obtain basic analysis anchor points and to help estimate achieved fracture dimensions, provides a fracture design tool that is tied to real measurements, and performs production data analysis and reservoir modeling, according to the company's website.

Magnum Oil Tools

Magnum Oil Tools offers completion tools and other associated wellbore isolation technologies for hydraulic fracturing operations worldwide.

The Magnum Vanishing Plug dissolves in an extended range of temperatures, uses any water type and breaks down predictably. *(Image courtesy of Magnum Oil Tools International)*

Liberty has a hydraulic fracturing capacity of 560,000 hhp. *(Photo courtesy of Liberty Oilfield Services)*

The company's products are engineered to help operators navigate a variety of application-specific completion characteristics that include high-stage counts, HP/HT, restricted wellbore applications and more.

"The Magnum Vanishing Plug (MVP) was the industry's first dissolvable frack plug—holding strong and offering reliable flowback without the need to mill out," the company said. "Perfect for long laterals, the MVP dissolves in a wide range of temperatures, uses any water type and breaks down more predictably than other dissolvable frack plugs."

The company offers a wide range of composite and dissolvable frack plugs, cement retainers, pressure control disks, flotation devices, setting tools and other niche completion technologies.

Mohawk Energy

Mohawk Energy is a developer of expandable tubulars. The company provides well integrity, wellbore recompletion and openhole products. Mohawk Energy develops, manufactures and installs expandable tubular technologies that are designed to solve the most critical downhole challenges.

Mohawk Energy's ReFracPatch product allows the operator to mechanically isolate the previously produced wellbore in a one trip deployment with only a limited reduction in casing inside diameter. One recent multiwell example of this was a recompletion of laterals, covering up to 4,500 ft, allowing high-rate fracturing operations to be completed. The FracPatch product line allows the operator to cover prematurely opened frack sleeves or misplaced perforations in the wellbore. Plugs can be set inside or passed throughout the patch to continue fracturing operations.

Prejob inspection takes place before mobilizing Mohawk's FracPatch. *(Photo courtesy of Mohawk Energy)*

NCS Multistage

NCS Multistage is an independent technology and services company specializing in multistage completions.

The company provides coiled tubing (CT) fracturing services, fracturing systems, liner hangers, its AirLock buoyancy system and reservoir services. NCS' fracturing systems include casing sleeves with annular fractures, casing sleeves with through-CT fractures (half-straddle option), sand-jet perforating with annular fractures and straddle refracturing systems.

The company's primary offering is its Multistage Unlimited family of completion products and services that "enable efficient pinpoint stimulation, which individually stimulates each entry point into a target formation," the company said on its website. The "Multistage Unlimited products and services are typically utilized in cemented wellbores and enable customers to precisely place stimulation treatments in a controlled and repeatable process, compared with conventional multistage completion methods."

NCS has operated throughout North America and in Argentina, Australia, China and Russia, with a record of more than 7,800 field successes, according to the company's website.

NOV

NOV's Intervention and Stimulation Equipment business unit offers pressure pumping, wireline and aftermarket equipment as well as complete coiled tubing (CT) systems. NOV's pressure pumping products include fracturing units, blenders, proppant handling and storage equipment, acid units, chemical additive systems, cementing equipment, hydration units, flowline equipment as well as data vans and software.

The company's individual equipment and full system offerings span across the full life cycle of an unconventional well. From well construction and completions to hydraulic fracturing, flowback, CT and well testing, NOV's equipment is designed to handle longer laterals, more stages and higher pressures.

In June 2018 NOV released GoConnect condition-monitoring services for intervention and stimulation equipment. The services provide real-time process monitoring, predictive analytics and condition-based maintenance capabilities for NOV's pressure pumping, CT, nitrogen and wireline equipment, a press release stated.

In June 2017 the company released several new completions technologies, including the Bulldog Frac sliding-sleeve annular fracturing system, which is designed to provide pinpoint accuracy, zonal

An independent hydraulic fracturing service provider deploys a fleet in Hearne, Texas. *(Photo courtesy of NOV)*

isolation and improved reliability; the Bullmastiff ball-drop openhole sliding-sleeve sand control fracturing system; the Rottweiler product line of compact, high-performance fracture plugs for the plug-and-perf market; and ReAct remote activation technology, which offers remote signaling capabilities for valves and sleeves for a variety of applications and completion designs.

Packers Plus Energy Services Inc.

Packers Plus provides multistage completion systems for a variety of applications, including horizontal, multilateral and HP/HT wells. The company has operations in Canada, the U.S. and internationally.

This year Packers Plus released new technologies under the TREX cemented product line, a suite of stimulation technologies designed to increase operational efficiency and reduce risk in cemented completions.

The TREX cemented completion solutions line includes single-point entry and limited entry ball-activated sliding sleeves, coiled tubing activated sliding sleeves, liner hangers, hydraulic toe sleeves and composite plugs. "Notably, the QuickPORT IV limited entry sliding sleeve has achieved milestones with high stage count wells," the company said.

Recent challenges overcome using Packers Plus completion technology include a multilateral offshore well in the North Sea and meeting the needs of increased stimulation program intensity to maximize reservoir coverage with an upgrade of the company's multistage completion system to StackFRAC HD-X.

PropX

Proppant Express Solutions LLC (PropX) is a privately held company headquartered in Denver.

The company's last-mile proppant delivery system is a containerized technology for last-mile proppant delivery to hydraulic fracturing operations. It is designed to be much quieter, lower last-mile trucking costs, provide less truck traffic, eliminate demurrage, offer more flexible maximized load volume and produce less dust than incumbent methods, according to the company. PropX systems also reduce the hazard of silicosis.

"The ability to unload and load sand containers in less than 10 minutes (versus 45 minutes for the same proppant mass with pneumatic transfer) dramatically reduces the truck 'staging' problem and the resultant waiting time or demurrage fees charge by the truckers while standing by waiting on their turn to unload," the company stated on its website.

In addition, "PropX, because of its gravity driven system of unloading sand coupled with our fully enclosed conveying system, does not require pneumatic blowers, resulting in a safe, fast operation, which generates very little noise or dust," the company said. PropX systems have delivered billions of pounds of proppant to customers in numerous oil and gas basins across the U.S.

ProTechnics

Core Laboratories' ProTechnics division focuses on industry challenges in reservoir optimization. "Aligning its technology and engineering team's basin experience with each operator's specific objectives, ProTechnics implements strategic diagnostic


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plans to facilitate better decisions when hydraulically fracturing wells," the company said.

High-level objectives and initiatives of note include infill development and the impact of fracturing hits, well spacing in stacked pay environments, evaluating horizontal target productivity and stage reduction through perf cluster optimization.

Among the technologies utilized to address these challenges are SPECTRASTIM proppant tracers along with the SPECTRASCAN spectral gamma ray imaging tool (cluster efficiency, diversion effectiveness, isolation, stage/cluster optimization and well spacing) and FLOWPROFILER oil and water tracers (profiling production along a lateral, well spacing and layer to layer communication).

Offshore, ProTechnics implements its Spectral PACKSCAN memory gamma density technology to simultaneously evaluate fracture placement and annular pack quality. Washpipe conveyance provides data with zero additional rig time, quickly informing decisions to reduce rig costs and accelerate time to production, according to the company.

Rubicon Oilfield International

Rubicon Oilfield International is a manufacturer of drilling, completions, fishing and production products, providing tools for well construction, hole conditioning, cementing and fracture plug milling and other stages of the life cycle of a well.

In May 2017 Rubicon acquired Choice Completions Systems LLC, an emerging technology company specializing in the supply of downhole products for conventional and unconventional completions. Through the acquisition of Choice Completions, the company also is providing a new fracture plug technology with a composite product at 5 lb in weight that is thought to be the lightest plug available, according to the company.

In June 2017 Rubicon acquired World Oil Tools Inc., a manufacturer and supplier of specialty inflatable products and downhole completions technology.

Schlumberger

Schlumberger offers hydraulic fracturing and matrix stimulation treatments for all types of environments.

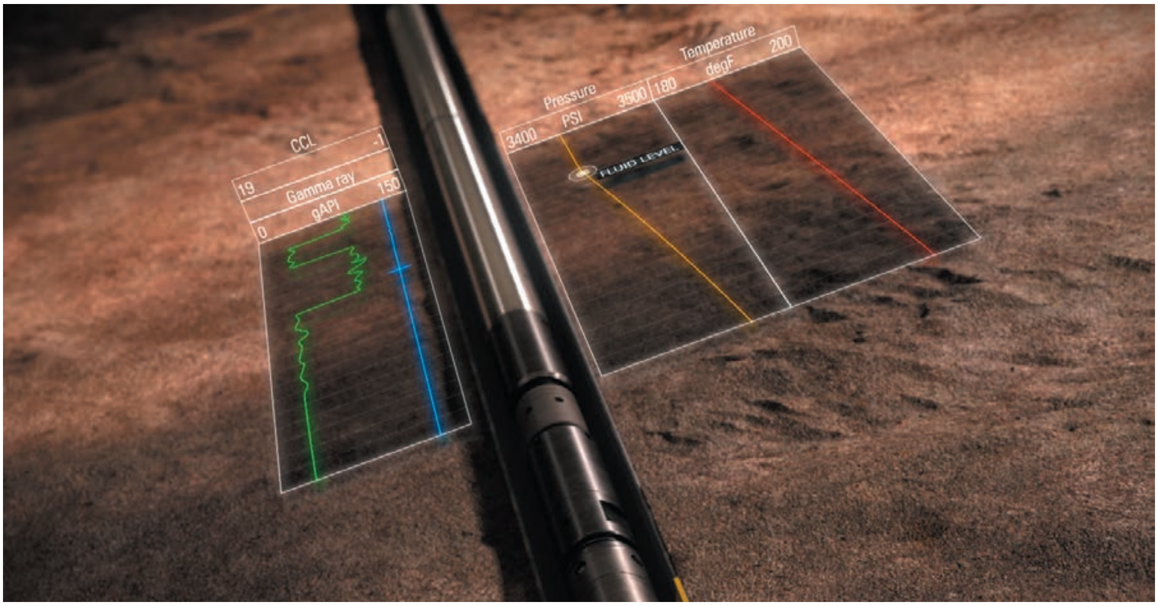
Multistage fracturing and completion services from Schlumberger include fracturing with coiled tubing (CT), multistage stimulation systems, shale gas dynamic fluid diversion services and fiber-based fracturing services.

Schlumberger multistage stimulations systems include plug and perf (PNP), dissolvable PNP and continuous pumping stimulation. The systems can be used in vertical, deviated and horizontal wells.

In late 2017 Schlumberger purchased Weatherford's pressure pumping assets and pump down perforating business, which Schlumberger merged with its existing hydraulic fracturing operations, multistage completions, sand mining and logistics, and CT operations for its OneStim well completions business in North America Land.

In March 2018 Schlumberger released its Tempo instrumented docking perforating gun system. "This

At OTC 2017 the RubiconTAINER was outfitted with all of the Rubicon product lines including completion, drilling, fishing and abandonment, and well construction solutions. *(Photo courtesy of Rubicon Oilfield International)*



The Tempo system fully integrates a plug-in gun with real-time advanced downhole measurements for monitoring and confirming operations to mitigate risk while increasing safety, reliability and efficiency. *(Image courtesy of Schlumberger)*

combination of a plug-in gun design with real-time advanced downhole measurements enables and monitors the well's dynamic underbalance to create clean perforations that boost reservoir productivity," a press release stated.

In addition, last year the company released its SpectraSphere fluid mapping-while-drilling service, which delivers downhole fluid composition during drilling with real-time pressure measurements while drilling.

Shale Support

Shale Support supplies white fracture sand as well as logistical support throughout all major shale plays in the Americas. The company mines fracture sand from its properties in Picayune, Miss., and can transport its proppant via road, rail or barge through North America.

After treating fracture sand, Shale Support uses its particle analyzer to quality-test sand from each batch. "With the particle analyzer, facility operators know within five minutes whether or not the sand meets American Petroleum Institute and customer standards," according to a Shale Support article that appeared in *E&P*.

In addition, the company's Delta Pearl proppant is clean, white sand produced for shale applications in a variety of mesh levels. Used regularly in the Marcellus-Utica, Permian, Eagle Ford and Haynesville/

Shale Support mines white fracture sand from its properties in Picayune, Miss. *(Photo courtesy of Abstract Media)*

Tuscaloosa shale plays, Delta Pearl fracturing sand is designed to provide low turbidity.

Superior Energy Services

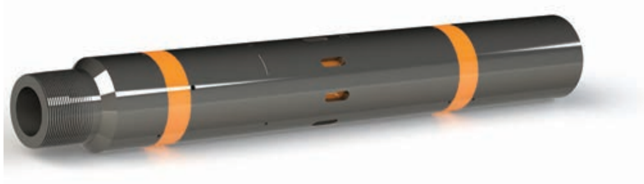
Superior Energy Services provides specialized oilfield services and equipment that are focused on servicing the life cycle of the well for oil and gas companies worldwide. The company has a full line of completion and production services, including pressure pumping, equipment rentals, fluid handling and well servicing operations in several active resource plays in North America.

As part of the Superior Energy Services family of brands for completion-related services, Pumpco Energy Services delivers hydraulic fracturing services focused on horizontal well completions and stimulation. Pumpco can deliver a variety of fluid designs including diverter, slickwater and gelled water fractures using gelling agents to increase viscosity. If required, Superior has the ability to provide stable, crosslinked or hybrid fluid systems designed to address any range of temperature, the company said. The company also offers several pumping techniques, including treatments on single-well pads, zipper fractures on multiwell pads and pumpdown assists for plug-and-perf jobs.

Superior's rental equipment supports conventional and unconventional completions, with specialized BOPs, choke manifold equipment spreads, fracture heads, and flowback and well testing services. Fluid handling includes services used to obtain, move, store and dispose of fluids involved in the development and production of oil and gas reservoirs, including specialized trucks, fracturing tanks and other assets that transport, heat, pump and dispose of fluids.

TAM International Inc.

TAM International, an independent oilfield services company, offers R&D, product development and operating techniques. The company provides multistage fracturing systems for both openhole and cemented unconventional wells. The systems consist of technologies to enable positive placement and isolation of acid stimulation or hydraulic proppant fracture treatments. The tools are designed to work with specific fluid requirements, offering flexible options.



The PosiFrac Toe Sleeve assembly is designed for horizontal cemented or uncemented multistage fracturing completions. *(Image courtesy of TAM International)*

Additionally, TAM designed and developed the PosiFrac Toe Sleeve assembly for cemented or uncemented completions where a casing pressure test is desired to confirm casing integrity prior to opening the toe sleeve. It allows a casing integrity test that can he held for as long or as short as desired without the need to pressure above the test pressure to open the sleeve.

The PosiFrac Straddle System assemblies can be used for a wide array of applications including acidizing, fracturing, flow testing, washing perforations and pressure testing. It is designed for multiset operations and is reliable in both horizontal and vertical applications. An option on the Straddle System utilizes the Insta-Set Valve, which does not require a ball to drop from surface.

Pumpco employees collaborated on a well site in the Permian Basin. *(Photo courtesy of Superior Energy Services)*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TechnipFMC

TechnipFMC provides subsea, onshore, offshore and surface technologies and services.

A surface valve installation of an IS-A backpressure valve at the TechnipFMC training facility took place in Tomball, Texas. *(Photo courtesy of TechnipFMC)*

For surface technologies, the company offers solutions for drilling, completion, production, midstream and transportation needs. The Surface Technologies segment designs and manufactures products and systems, and provides services used by oil and gas companies involved in land and offshore E&P of crude oil and natural gas. Surface Technologies designs, manufactures and supplies wellhead systems as well as technologically advanced high-pressure valves, flowlines and pumps used in stimulation activities for oilfield service companies. Surface Technologies also provides fracturing systems and services as well as production, separation and flow processing systems for E&P companies in the oil and gas industry. TechnipFMC manufactures most of its products in several facilities located worldwide.

TechnipFMC's exploration and drilling capabilities have expanded with the acquisition of Plexus Holding's jackup business in February, further extending its upstream, midstream and downstream products and services.

In multiwell developments, TechnipFMC's integrated offering "can deliver up to $1 million in savings per well as compared to developments using multiple vendors," according to the company.

Universal Pressure Pumping Inc.

Universal Pressure Pumping Inc. (UPP), a subsidiary of Patterson-UTI, provides pressure pumping services that include hydraulic fracturing, cementing, nitrogen, acidizing and related services. The company also provides natural gas-powered fracturing equipment, has the largest dual-fuel fracturing fleet in the Appalachian Basin, and offers refracturing experience and data acquisition for reservoir enhancement.

UPP, headquartered in Houston with regional locations in multiple basins across the U.S., provides services in the Permian Basin, Midcontinent, Appalachia as well as North, East and South Texas.

UPP's OffSiteFrac service displays near real-time hydraulic fracturing job data to operators at remote sites, which allows viewing of job-critical data without leaving the office.

U.S. Silica

U.S. Silica provides mining, processing, testing and mine-to-wellhead distribution for proppant demands in hydraulic fracturing operations. The company's premium Northern White and In-Basin fracturing sands, including all conventional grades in addition to the company's MicroStim and MicroStim Plus

U.S. Silica has a facility in Tyler, Texas. *(Photo courtesy of U.S. Silica)* micro proppants, have been proven in tight gas, coalbed methane, and shale gas and liquid applications.

In-house engineering and testing ensure grain consistency and performance under pressure and that proppants meet or exceed ISO 13503-2 and API RP 19C specifications for particle distribution, roundness and sphericity, turbidity, acid solubility and crush resistance. An extensive rail fleet, 50-plus transloads and a network of regional and in-basin mines provide extensive access to sand for U.S. Silica customers.

Additionally, SandBox Logistics, a wholly owned subsidiary of U.S. Silica, provides a new approach to proppant storage, handling and wellsite delivery. With a logistics process and containerization solution, "SandBox can lower costs, increase operational efficiency and drastically reduce the health and safety impact of silica dust on any hydraulic fracturing jobsite," according to the company.

Weir Oil & Gas

Weir Oil & Gas provides well service and stimulation pumps, flow control products and replacement expendable parts from brands including SPM, Mesa and Novatech. Pressure control includes brands such as Seaboard, which provides wellheads, valves and fracture trees, and Mathena, which delivers drilling mud-gas separation equipment including chokes, separators and environmental containment equipment. The company offers mechanical and rotating equipment repairs and upgrades, oilfield and drilling equipment repair and certification, asset management and field services.

In May 2018 Weir released Weir Edge, its newly branded aftermarket services program. Weir Edge is designed to extend equipment life and reduce total cost of ownership, according to a press release. "Weir Edge provides a three-pronged offering: engineers to diagnose the root cause of downtime, specialized field experts to provide repairs and strategically located service centers to offer support, parts, service and customer training," the release stated.

In July 2017 Weir acquired KOP Surface Products, a provider of advanced pressure control wellhead technologies, systems and services. ■

SPONSORED CONTENT

Economics of Frac Pump Fluid Ends

Two reliability measures that can help reduce TCO and NPT. *(Potentially $1,000,000 annual savings on a 20 Pump Frac Fleet)*

"How many hours do your fluid ends get?" It's a common question in the "frac patch" – and one of the most difficult to legitimately answer. Hours alone do not kill fluid ends on positive-displacement frac pumps. Two primary "killers" lead to the seven widely accepted failure modes:

1. **High pumping pressures** – pushes metallurgy tensile strength beyond endurance limit
2. **Inadequate maintenance** – an age-old problem for mechanical equipment

The "fluid-end hours" question is a holdover from a pre-stainless steel era before ~2013. Until five or six years ago, 4330 carbon steel was industry standard metallurgy for fluid ends. For decades, frac crews rarely ever pumped at pressures over 5,000 to 6,000 psi. Lower pumping pressures typically kept intersecting bore stresses below carbon steel's limits. The highly corrosive nature of proppants chemically and mathematically cut carbon steel's endurance limit in half.

As frac treating pressures climbed toward 10,000 psi and higher, it was only a question of "when" carbon-steel fluid ends would crack. Internal stresses at intersecting bores increase exponentially as pumping pressures increase beyond 8,500 psi, so carbon-steel fluid end operating life became shorter and shorter. Before widespread migration to stainless steel, fluid-end life expectancy had dropped to 150-250 high-pressure pumping hours.

Accurately answering the *hours* question requires defining "hours." Percentage of engine hours? Or transmission hours? Or accurately recorded high-pressure pumping hours? Many pressure pumpers once believed fluid ends pumped upwards of 80% of engine hours. Yet, closer analysis does not correlate unrealistic pumping hour estimates to nominal pump use. High-pressure pumping hours by realistic estimations fall in the ~20% vicinity of engine hours.

Frac 1 CONNECT™

Frac fluid ends are still considered expendable – albeit the most costly expendables on a frac spread. When a fluid end must be swung from the pump for repair or maintenance, it is easy to lose track of pumping time to-date on a unit, then "best guess" hours when it returns to service. Maintaining frac pumps is challenging; keeping accurate service records adds to the challenge.

The number of high-pressure hours a fluid end can withstand is highly debated. A fluid end may fail in two hours if a packing-bore greaser malfunctions. A fluid end may last 200 pumping hours and experience a valve seat-deck washout. Or it may accumulate 2,000+ pumping hours before it is decommissioned and retired to the boneyard. Its ultimate failure mode is determined by random operating conditions and thoroughness of routine maintenance.

Five fluid-end failure modes were identified in a 2016 *Upstream Pumping* article "The Five Failures of Fluid Ends." Kerr Pumps addressed these failure modes with its Super Stainless™ metallurgy, design-specific intersecting bore geometries, and patented Super Seal™ technology in the packing, suction and discharge seal bores. With longer operating life, two more failure modes occur at a growing rate: Thread cracking/face peeling at the suction retaining nut, and opposing stress-cracking at the connecting flange.

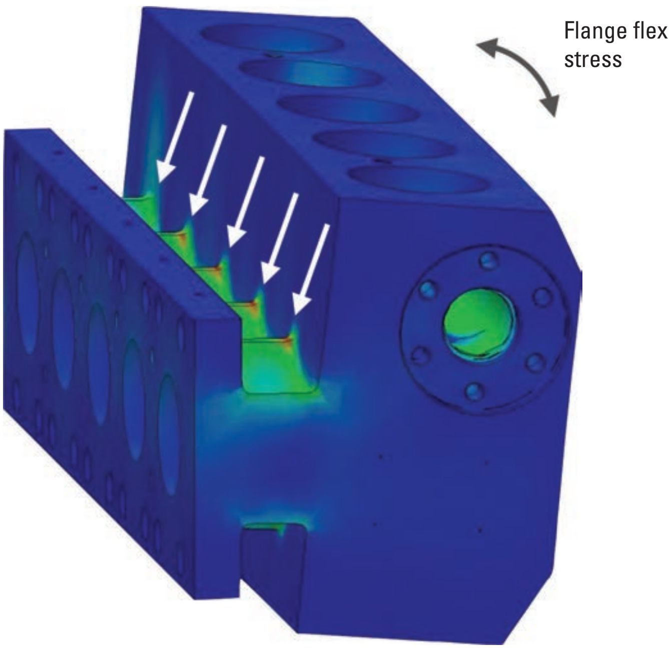
Kerr Pumps responded to the 6th and 7th failure modes with the January 2018 rollout of its patent-pending Frac 1 CONNECT™ fluid end. The F1C™ incorporates a bolt-on cover cap to disperse cyclic stress (more than 287,000 pounds) on suction caps across eight, gall-free studs and nuts.

Additionally, Kerr Pumps engineers began seeing minute flexing cycles at the connecting flange in FEA simulations. This led to a two-piece flangeless design that attaches a highly rigid CONNECT™ plate to the power-end's stay rods. With a Frac One™ fluid end attached to a CONNECT™ plate, flexing movement was reduced by 420% –likely contributing to longer packing and stay-rod life observed in field trials.

Reliability is Like Buying Uptime

Fracs are more efficient when pumps have less down time –longer operating life at lower total cost. Two widely accepted Key Performance Indicators (KPIs) for frac equipment are:

- Total Cost of Ownership (TCO) – accumulated costs over equipment's operating life
- Non-Productive Time (NPT) – time on site when planned work cannot be performed



Frac fluid-end TCO can be significantly higher when full operating life is shortened by premature failure. Total costs accumulate rapidly when routine maintenance occurs at compressed intervals. Arguably the most menacing demon on frac jobs is NPT – missing schedules when a pump is offline. Like any corporate asset, it is not Returning On the Investment (ROI) when it is not generating profitable revenue.

To improve these time-related KPIs, it pays to find ways to extend these *reliability* measures:

- MTBM – Mean Time Between Maintenance
- MTBF – Mean Time Before Failure

Make no mistake: High-pressure fracturing today is arguably the most intense it has been. With the capital required for hour-by-hour, stage-by-stage, job-to-job operations, reliability affects both time and cost. Yet many component suppliers grew to market-controlling proportions via simple "razor and blade" planned obsolescence replacement models. With lower commodity pricing, increased efficiency across the supply chain is required. Extending MTBM and MTBF can drive substantial time and cost savings.

Extending Mean Time Between Maintenance (MTBM)

Most frac service providers accept some basic assumptions about maintenance cost and intervals on valves and valve seats. To keep it simple, assume a fluid end pumps 10 hours/day for 20 days/month. In six months, this accumulates 1,200 pumping

TABLE 1: PURCHASE PRICE AND VALVE SEAT MAINTENANCE COST COMPARISON

Fluid End plus Valve Seat Maintenance Costs	6 Month Total		
	Legacy	F1C	Savings
Fluid End Cost	$62,000	$49,995	19%
Valve Seats	$20,800	$6,540	69%
6 Month Total	**$82,800**	**$56,535**	**32%**
12 Months	**$165,600**	**$113,070**	**$52,530**
20 Pump Fleet	**$3,312,000**	**$2,261,400**	**$1,050,600**

hours, respectable fluid-end operating life assuming no irreparable failures.

This translates to two fluid ends per pump each year. An hour of a maintenance technician's time is estimated (fully burdened) at $100 per hour, not including truck and tools sunk costs or travel time. The fluid end model for this analysis is a 10-inch between center-bore quintuplex running #4 valves and valve seats. The Legacy flanged-style fluid end costs $62,000 and the Frac 1 CONNECT™ costs $49,995 (table 1). Opportunity cost for a Legacy-style fluid end idled for repairs will be the expense of purchasing a new fluid end as a temporary replacement.

Traditional Valves and Valve Seats

Valves are the first internal consumables routinely replaced. Industry standard valves on average cost $50 each. Ten valves per quintuplex fluid end are typically swapped out after 25-35 hours of harsh environment pumping and depending on proppant pumped. It is commonly accepted the second valves on a set of valve seats lasts 75-80% as long (because preceding valves slightly deformed each seats' strike-face). Kerr Pumps is field testing a valve design engineered to extend the maintenance interval at a commensurate price point that does not affect the valve seat

Super Seat™

strike-face. On average, traditional valve seats cost $60 each and are swapped on 30-60 hour increments.

Super Seats™

Fluid-end technicians dread valve seat replacement. Kerr Pumps' patent-pending Super Seat™ reliably extends maintenance intervals over five times (v. traditional valve seats) in the worst pumping environments – and measurably longer in more favorable conditions.

The patent-pending "shoulderless" seat with tungsten carbide ring at the strike-face has consistently performed up to 5X (and sometimes 10X) longer for less than 2X cost ($89 for a #4 valve seat). Kerr Pumps' Super Seats™ consistently ran up to 200 pumping hours in the Haynesville Shale before routine replacement as a precaution.

Extending Mean Time Before Failure (MTBF)

Fluid-end failures are an unfortunate reality with intense duty cycles in harsh environments. Yet seeking incremental increases in operating life within the economic limits of today's frac patch can be a challenge.

Anyone reading this who has ever tackled economic time and cost analysis understands the many unexpected frac job variables that can make a well-thought, controlled analytical study look absolutely out of control. Anything that *can* happen, *might* happen. Should one factor for each "what if" potential failure mode to build a "contingency bank" of time and money?

In 2014 Kerr Pumps entered the market with replacement fluid ends for standard frac pumps and began experiencing varied failures at frequencies similar to other suppliers. Intersecting bore cracks are the kiss of death; that fluid end is destined for the boneyard. Shifting to stainless steel pushed intersecting bore cracking out to a high-hour, end-of-life failure mode – if it happens at all anymore.

Packing-bore Washout

Packing-bore washout is today's most prominent failure mode (roughly 40% of all fluid ends). It isn't a widow-maker, but it can sideline Legacy-style fluid ends for a $5,000 per-bore weld repair (including transportation) for up to two months. A $62,000 backup fluid end must be purchased as a replacement (table 2). Maintenance usually requires a couple of hours for each fluid end swing with two service technicians. Plus, it is widely acknowledged that most weld repairs may only return a fluid end to operating service for another ~150 pumping hours before end-of-life cracking failure. Total cost includes two months' downtime –*lost opportunity cost* – plus premature cost of a replacement fluid end.

Kerr Pumps' *Transfer the Wear*™ design philosophy inspired its patented Super Seal technology with removable stuffing box sleeve in the packing bore. If packing-bore washout occurs with a Frac 1 CONNECT™ fluid end, washout transfers to an $800 sacrificial sleeve that can be changed in the field if necessary. No material downtime alleviates need for a redundant fluid end.

Seat-deck Washout

The next most common and often life-ending failure mode is valve "seat-deck washout" at the lower suction valve seat deck. This begins with valves' constant high force hammering onto seats at the strike-face. The OD of the metal-to-metal strike-face is near directly aligned above the landing deck circumference for the seat (on the fluid end), so a radial shear point can start. Under the right random conditions, this shear point weakens and allows high-pressure fluid to jet through the seat to create seat-deck washout failure. As in packing-bore washout, this area can sometimes be weld-repaired for similar $5,000 cost. This requires two service technicians for two, 2 hour fluid end swings, and a replacement fluid end for two months out-of-service downtime.

Kerr Pumps' answer to seat-deck washout is its patent pending Super Seat™ design. It eliminates the shoulder and almost any possibility of seat-deck washout. A tungsten carbide ring at the metal-to-metal strike-face withstands the valve's high force pounding. Through seven months field testing, the Super Seat™ design eliminated seat-deck washout. There were no weld repair costs or out-of-service downtime, nor need for replacement fluid ends.

Suction-Cap Thread Cracking, Face Peeling and Seizing

Transition to stainless steel fluid ends slowly extended operating life and revealed the next weakest link in the chain: thread cracking / face peeling on the front suction side. Thread cracking results as suction retaining nuts back-out ever so slightly and begin pulsating with plunger pumping. Threads are inherently machined stress risers. Tiny fractures can form along the second or third thread from the front on the cap and inside the front suction bore.

Face peeling is when that superficial crack occurs inside a suction bore, then propagates outward to the fluid end's front surface, producing a visible circular fissure around the weakened bore. This failure mode usually does not occur until 500-600 pumping hours, but it is a catastrophic fatigue failure. It immediately removes a fluid end from service and requires a new replacement.

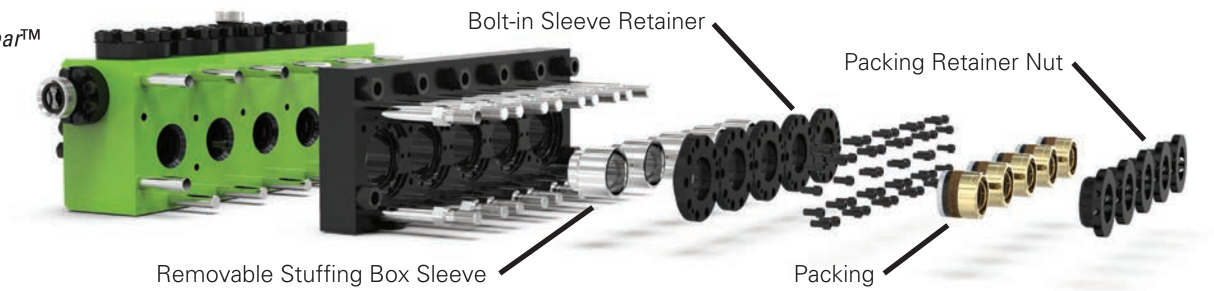
One cannot exaggerate how punishing duty-cycles affect frac-pump systems. As frustrating as thread cracking and face peeling can be, imagine another extreme situation when a front side cover cap is completely seized in the bore! This can happen when cracked threads cross paths or foreign debris becomes impregnated on opposing thread faces from the load created with each plunger stroke.

Kerr Pumps engineers conducted a root cause failure analysis of this increasingly problematic scenario. Their findings proved over 287,000 pounds of cyclic load can be forced upon a retainer nut with a 4.50" plunger when pumping at 12,000 psi. Such a pressure load would require 19,404 lb-ft of torque on the cap to overcome that cyclic stress. Add galling plus wear and tear on fluid-end and retainer-nut threads. Result? Regular thread cracking.

TABLE 2: EXTENDED OPERATING LIFE COST COMPARISON

Packing Bore Washout at 600 hours	Legacy	F1C	
Fluid End Washout Weld Repair Cost	$5,000		
Replacement Fluid End Cost (while original out for weld repair)	$62,000		
Replacement Sleeve		$800	
Service Technician Cost	$800	$400	
Total Legacy Replacement FE or F1C Repair	**$67,800**	**$1,200**	
6 Month Total (*table 1*)	**$82,800**	**$56,535**	
6 Month Maintenance, Repair and Replacement FE Total	**$150,600**	**$57,735**	**Savings 62%**

Thread cracking/ Face peeling

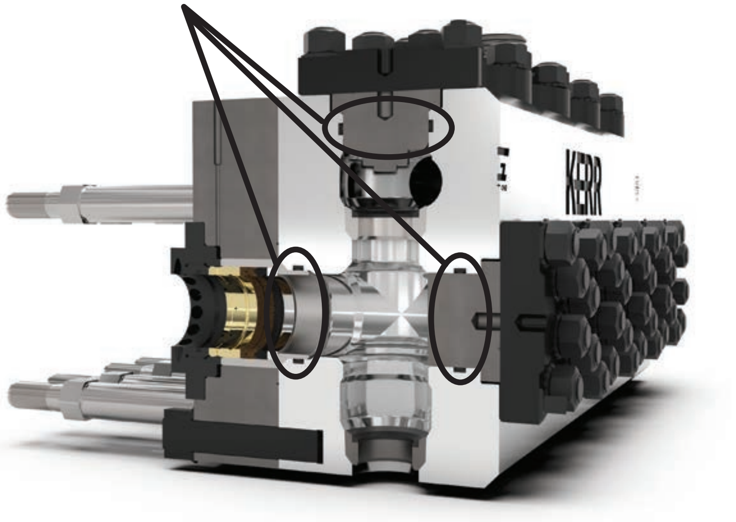


In 2017 Kerr Pumps created its patent-pending Frac One™ bolt-on cover cap design to combat this problem. By spreading load to 8 studs per front bore, load for each stud was reduced to only 35,934 pounds. Now each nut needs only 700 lb-ft of torque to dissipate cyclic stress.

Packing Retainer Nut Damage

Whether related to maintenance or intense pulsation, a threaded packing retainer nut on the plunger side of a fluid end will gradually back-out from pulsation. Once a packing retainer nut enters the stroke of a plunger clamp, the clamp begins smashing into the backed-out nut.

In a Legacy fluid-end this hammering effect likely will damage threads cut into the fluid end to hold it –even to irreparable failure. To remove all threaded bore connections, Kerr Pumps utilized a bolt-in sleeve retainer that is ID threaded for the packing retainer nut. If a packing nut backs out and gets hammered in by the plunger clamp, it is a simple fix to replace the sacrificial bolt-in sleeve retainer.



Washboarding

The next three failure modes are less common, but happen nonetheless. They are: pulsation wear or "washboarding" in the fluid end at the packing on the packing bore, and at the D-rings around the suction and discharge plugs. Leakage through a wear ring (or series of rings in the case of packing washboarding) may occur in the suction or discharge bores. The remedy (again) is costly weld repair and up to two months downtime. Experience shows these welds are further away from the intersecting bore and usually last the remaining expected life of the fluid end.

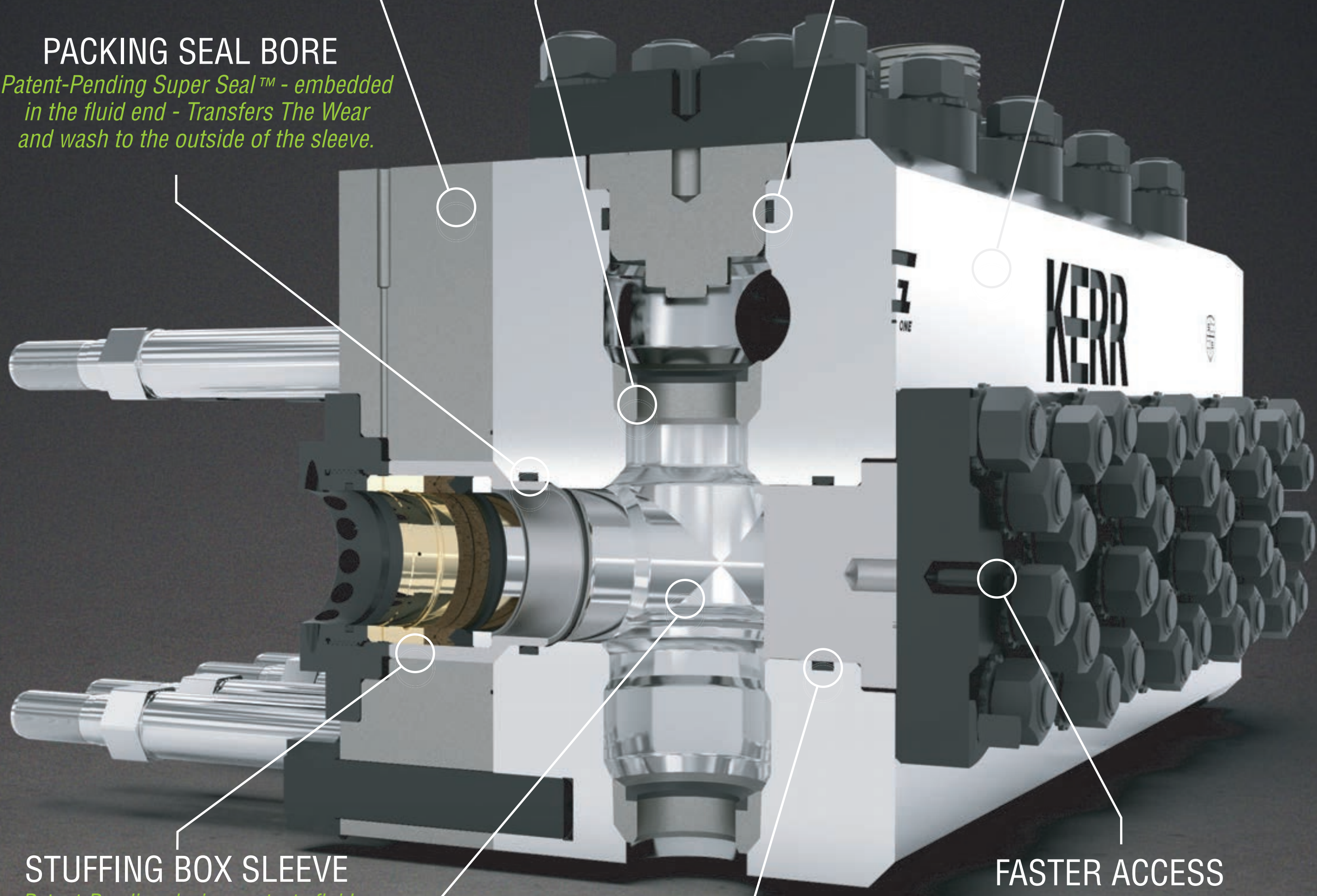
Kerr Pumps' answer to this failure is to *Transfer the Wear*™ to a sacrificial suction or discharge cap (or removable stuffing box sleeve), away from the expensive fluid end. Transferring wear is the primary way a Frac 1 CONNECT™ fluid end extends its useful operating life and reduces Total Cost of Ownership.

The Economic Differences

Solving the first five failure modes incrementally extended fluid ends' useful operating life. These plus the next weakest links (sixth and seventh failure modes) collectively inspired Kerr Pumps to develop, design and deploy the Frac 1 CONNECT™ fluid end.

The frac industry is still recovering from its worst recorded downturn. Pressure pumpers and their customers demand more efficient fracs driven by new technologies at a lower price. Kerr Pumps accepted that challenge and delivered its Frac 1 CONNECT™ with greater reliability (longer MTBM and MTBF) to reduce TCO and NPT. ■

FRAC ONE CONNECT



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KERR PUMPS

Technology Shift on Deck as Operators Reinforce Optimization

Players move to deliver efficiencies for next phase of unconventional hydrocarbon development.

By Blake Wright
Contributing Editor

Pressure pumpers continue to work to move the needle when it comes to the rate of successful hydraulic fracturing jobs worldwide. A blitz of activity across the U.S. conventional and shale plays over the past several years has put the nation in the catbird seat when it comes to hydrocarbon production. Plans to bring in natural gas imports quickly shifted into plans to export the commodity, while oil production from tight formations has continued to impress. It is expected help the nation's crude oil production per day balloon to as much as 12 MMbbl/d by 2040, according to the U.S. Energy Information Administration's "Annual Energy Outlook 2018." Tight oil is expected to account for about 65% of the overall growth in domestic oil production between 2017 and 2050.

The numbers are robust, but could move even higher as new technologies and strands of automation are introduced into the hydraulic fracturing mix, and maintenance and logistics around frack jobs improve. There is a transition happening in U.S. unconventionals. As operators begin to move from leasehold-style drilling and completion efforts to more of a "factory" or manufacturing mentality, they are bound to latch on to proven methods of fracking that both provide the most bang for their buck as well as offer the optimal solution for the project at hand.

"The fracking industry has to continue to focus on ultimate well productivity," said Scott Gale, strategic business manager—Production Enhancement, Halliburton. "What are we doing to make better wells? Our clients have been in a mode of experimentation over the last several years and, as everyone has sort of staked their claims, we're now moving toward well optimization and a focus on productivity. It becomes a critical success factor for us. While it has always been important, I think it will continue to be a driving part of the discussion for what technologies receive investment and which ones don't."

That is not to say that operators' appetites for new technologies are expected to wane, but it stands to reason that they may become more selective. Those that make the transition to fueling optimal production and squeezing out costs where possible will likely receive the lion's share of attention from producers.

Automation and other tech

For several years, Schlumberger has been a champion of automation across the oil patch from drilling to well stimulation. Conventional stimulation equipment automates only a few mixing and pumping functions, which falls short of many of the demands of modern hydraulic fracturing operations, including the high volumes of fluid and proppant, more involved mixing requirements and continuous, high-intensity pumping operations.

"Our Automated Stimulation Delivery Platform allows us to achieve higher operational efficiency in stages per unit of time by improving backside equipment reliability," said Bruce MacKay, OneStim chief technologist, Schlumberger. "It also allows us to move sand efficiently on location with minimal safety risk

The Automated Stimulation Delivery Platform automates and streamlines surface operations, resulting in a smaller footprint, sustained efficiencies and substantially reduced NPT. *(Photo courtesy of Schlumberger)*

(no forklifts, limited exposure to silica dust). The system integrates with our inventory control processes and is seamlessly integrated into our operational software to enable direct implementation of job designs right from the sales contract. Perhaps most importantly, the Automated Stimulation Delivery Platform enables us to be more efficient with people on location, enabling us to grow faster as we free experienced personnel to start new frack crews."

To enhance production, in 2018 Schlumberger OneStim began using the new WellWatcher Stim stimulation monitoring service to evaluate fluid placement in real time on frack jobs. The WellWatcher Stim service imports expertise in signal processing from seismic technology into the fracturing domain to extract information about subterranean situations from acoustic analyses of the observed pressure behavior of a well under treatment.

"We have learned to extract information about which zones accept fluid, and we can also directly evaluate plug integrity and well integrity using this service," MacKay said. "This service can be coupled to our existing BroadBand Sequence fracturing service (near-field diversion) and BroadBand Shield fracture-geometry control service (far-field diversion) techniques to deliver state-of-the-art control over fracture geometry."

These services, bundled together, represent a step-change in the tools available to control interwell interactions, or "frack hits," in infill drilling campaigns. Schlumberger has already been able to solve significant problems for operators facing challenges such as casing failures without needing to abandon significant portions of a horizontal wellbore using this approach.

"Schlumberger's OneStim business line uses a new and potent set of tools for subterranean fracture engineering to assist our customers with design, detection and control of fracturing jobs," MacKay added. "The Kinetix Shale reservoir-centric stimulation-to-production software and Planar3D fracturing design simulator based on a planar 3-D model offer rapid results based on new achievements in computational efficiency based on improved algorithms and cloud computing. For Lonestar Resources Ltd. Kinetix Shale software helped increase production by up to 86% in the Eagle Ford Shale."

Additional automation technology in the field of hydraulic fracturing is expected, but it is still early days for most. Whether it's an algorithm-driven workflow for selecting and designing frack stages or volumetric water and sand handling, industry is making strides toward introducing new automated components to fracking operations. However, these innovations are expected to be met with their own set of challenges.

"I think the challenges for industry will be the technical complexity of the challenges we're trying to solve and boiling down a lot of complicated engineering into a single algorithm or something that is going to drive full automation," Halliburton's Gale said. "There is a lot that has to be achieved, but the progress made in other industries, the computing industry, wireless data transfer technology are coming together to create a scenario for the industry to really take advantage of these various components that are going to contribute to automation. There is a lot of proof of concept stuff out there, and I think that where the data are available some are making some early progress. I'm not seeing anything that is effectively pulling it all together. I think the definition of automation is also important here. We see that customers are interested, from the fracturing services industry, in cost-competitive solutions that deliver appropriate returns. What do the overall economics look like and is the industry able to manage that appropriately?"

Halliburton continues to mature technologies around nanomaterials to try to extract as much hydrocarbons as possible, in addition to new modeling techniques and new capability to give the contractor a better understanding of completions impact on overall well productivity.

"Industry has gotten pretty comfortable with diverter type methodologies," Gale noted. "We anticipate seeing that to continue to evolve. The expectation is, if anything, that the industry will continue to be one of open-mindedness around technology and experimenting with new things."

Halliburton will be launching a handful of different technologies through the remainder of the year, some around its MicroScout Plus technology. The company also continues to evolve its legacy Access Frac approach.

"Having an effective kit of equipment is something we think is going to differentiate us moving forward," Gale said.

Sliding sleeve versus plug-and-perf

Resolution to the sliding sleeve versus plug-and-perf (PNP) completions debate may still be a moving target given both operator preference and individual well anatomy. Sliding sleeve, the openhole and, in theory, quicker of the two methods gained traction with operators for its elimination of nonproductive time (NPT) due to the absence of the need to trip in and out of the well and mill plugs. PNP, which is conducted in cased wells, has matured to a state of preference for many as new methods and technologies emerge. Some new PNP have eschewed the use of explosives, while others can employ dissolvable plugs that eliminate the need for milling. Both Schlumberger and Halliburton have such technology in their respective toolboxes.

"Primarily in U.S. land, we see plug-and-perf taking hold," Gale said. "We see nothing that is pressing that is going to significantly change that—call it market share or percent of jobs that are done with plug and perf. That continues to be the case. A lot of our technology development in and around that space is related to plug-and-perf. Our Illusion plug technology is something that continues to gain traction in the marketplace, and drives and facilitates a much more efficient operation. There are always going to be operators and reservoirs that are going to be more attuned with sliding sleeve, but again we continue to see that as a minority portion into the future."

For Schlumberger, it's the Infinity dissolvable PNP system, which uses degradable fracturing balls and seats instead of plugs to isolate zones during stimulation. The system is suitable for cemented, uncemented, vertical, deviated or horizontal applications in shale, sandstone and other lithologies, according to the contractor. The patented aluminum-based material degrades completely within hours or days, ensuring that production reaches its full potential. No additives are required. Fullbore access also increases the options available for post-fracturing evaluation and future production intervention.

Pulling cost from the equation

Maintenance and logistics remain two key drivers of cost when it comes to hydraulic fracturing. The number of moving parts in concert with increased truck activity and other equipment on the roads makes for a heightened level of potential failure points throughout any particular job. Industry continues to work to simplify the maintenance process as well as lower to the number of water and/or sand handling vehicles on the roads—no small feat given the increased levels of each required for today's more robust frack jobs.

"85% of the total cost of ownership of tools and equipment accumulates from the moment they are deployed until the day they are retired," said Jose Borges, technology life-cycle management manager, OneStim, Schlumberger. "Therefore, improving the management of assets throughout their life cycle is a primary concern for Schlumberger and our customers."

The transformation of Schlumberger's maintenance has achieved significant reliability and efficiency improvements through the adoption of digital technologies and analytics, centralized asset planning and the latest advances in prognostic health management for optimizing the maintenance of our pumps.


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A Halliburton crew prepares to deploy an Illusion dissolvable plug on a frack job in West Texas. *(Photo courtesy of Halliburton)*

"Through a range of sensors on the pumps coupled with advanced data analytics we are able to predict the onset of major component failures from our remote monitoring center in Houston well in advance of them happening," Borges added. "This allows us to remove the pump from the operation and do the required maintenance before it fails, which dramatically reduces maintenance costs as well as the requirements for back-up equipment on location."

Since 2014, these technologies have generated approximately 10% year-on-year savings in both capex and maintenance costs, according to the company. In the first quarter of 2018 alone, Schlumberger has created three extra fleets with its existing asset base by improving its equipment down by 25%, as well as increasing the average horsepower used by each pump by 5%.

Halliburton sees an evolution coming of how frack jobs are set up and deployed, with the overriding goal of new efficiencies and driving costs out of the overall system.

"I think there is room for optimization when it comes to logistics," Gale said. "We're seeing the move toward containerized proppant, multiple different offerings that are out there. That has generated a step-change in logistics costs. There is still a lot of water that is transported by industry unnecessarily. Given the quantity of materials that are being moved around for the deployment of a frack job there is definitely continued room for improvement there."

Slickwater completions reign

In an effort to find just the right completions cocktail over the past several years, the industry has experimented with several different mixtures with small changes in proppant concentrations and volumes, pump rates and fracturing fluids. Gel-based solutions emerged and made a few waves, most notably the price shock around guar, their central component, in 2011-2012. Gel and hybrid gel completions are still used today, but there has been a tectonic shift among most toward slickwater completions.

"There has clearly been a migration by industry from gel-based systems," Gale explained. "Part of that is in response to the types of fluid designs that are out there as people try and find the ceiling on proppant per lateral foot, and finding that optimized completion. Additionally, the migration to non-API spec sand as well as smaller sand grains has opened the door for slickwater-type systems to be used more prevalently. That trend is very real. What we see as more customers get more comfortable placing their completion designs using a slickwater system that the industry is very unlikely to revert back to cross-linked systems in earnest."

Halliburton continues to reevaluate its friction reducer portfolio. Technologies that made up its friction reducer system even three years ago have been completely replaced with new systems, new active polymers and multifunctional polymers.

"When the price of guar broke out of its historical band, it spurred off a lot of innovation in the industry that over the past couple of years has really come to fruition," Gale said. "Our slickwater portfolio today has a completely different complexion than it did even two years ago."

Radical fluid end design makes inroads

One of the most expensive consumables on a frack spread is the fluid end—the part of the pump that contains parts directly involved with the movement of fluid. It's the operation's punching bag, exposed to extreme environments including high pressures, abrasive materials and corrosive fluids around the clock. All of which contribute to the rate of fluid end failure, which can occur in as little as 100 pumping hours.

Kerr Pumps set out to find a solution to the fluid end dilemma and in February started shipping the Frac

One Connect, a Super Stainless fluid end that addresses many of the failure points in the classic model.

"One of the common failures for fluid ends for the longest time, especially when they were made from carbon steel, was cracking at the intersecting bores inside the fluid ends," explained Art Travis, vice president—Planning & Strategy, at Kerr. "Because of the high tensile and yield strengths of our Super Stainless II material, we were able to all but eliminate intersecting bore cracks. From there we kept researching to realize that there are mechanical properties in how you manufacture and how you mill the steel to relieve stresses and to reduce stress risers that are the first areas that tend to crack. We started studying what the best geometries would be inside the fluid end for each size and came up with repeatable manufacturing processes that can be done with the CNC machines that we have, where others would just try to round the edges in their de-burr process. For us, we believed that all but eliminated intersecting bore cracks. That was the big first one."

Kerr adopted a design philosophy it called "Transfer the Wear," where it transfers the wear to a sacrificial consumable part and away from the expensive fluid end/pressure vessel. The company realized that it could move the wear away from these internal components that tend to move with the pulsation of the pumping fluid end.

"So we put specially located seal glands in the fluid end that hold engineered seals designed to protect the gland of the fluid end as well as the seal. At this point you've transferred the wear from the fluid end to the suction cap," Travis said. "We have a removable stuffing box in our fluid end so we were able to move the wear to it. The stuffing box sleeve is sacrificial in two places. The first is the inside diameter if your packing goes and the second is the outside diameter that seals to a seal housed in a gland in the fluid end on the packing side."

The Kerr Pumps Frac One Connect fluid end bolts right up to existing stay rods with a more rigid flangeless design. It includes replaceable stuffing box sleeves with all seals embedded into the fluid end to prevent washouts. *(Image courtesy of Kerr)*

Still, other areas needed to be addressed, like thread cracking on the front of the fluid end. The problem was solved by using a cover cap with a patent-pending stud-and-nut system, allowing precision torque to load the fluid end past the cyclic stresses seen and keep the studs in a safer constant state of static load.

"Thread cracking has become more prevalent," Travis said.

Another area of concern was opposing stresses at the fluid end's flange connection. Kerr opted to eliminate the large flange in favor of a more rigid T1 steel connect plate. The change allowed the company to reduce fluid end flexing by 420%. Eliminating the flange had another benefit.

"If you look at an old style flanged fluid end, that is a lot of material," Travis said. "You have to rough out the whole flange, and there is scalloping you have to do so that you can get the nuts to thread onto the stay rods. What we ended up being able to do is get two fluid ends from one forging, which doubled our material capacity. We were also able to cut our machine time in half. That is how we were able to price it at a low market price. It is the most technologically advanced fluid end at the lowest price. This isn't some fire sale. This is how we've gone to market. It is very disruptive."

Kerr's goal with the Frac One Connect is to extend two reliability measures—a longer mean time between maintenance and a longer mean time before failure. The longer mean time before failure equates to a longer operating life, and the company has provided that through the design and inclusion of sacrificial consumables to extend the life, which effectively lowers the total cost of ownership.

"What we offer is time without increasing the price," Travis said. "A longer maintenance interval and to do less maintenance when you have to go into the head, and give it a longer operating life. It is a bit of a departure from the legacy form factor and, of course, we're all creatures of habit and change is difficult. There are more moving parts, but those have allowed us to distribute stresses that reduce or eliminate certain failures." ■

Making Data Actionable

Service providers and operators leverage analytics into well design processes.

By Brian Walzel
Associate Editor, Production Technologies

The emergence of the U.S. oil and gas industry as one of the pre-eminent suppliers on the world's stage has its roots in the economics of production. And on the ground floor of those economics can be found the seed that has grown into a forest: enhanced well designs. By now, the story is a familiar one—longer laterals, more intense proppant loads, tighter well spacing and increased stages are propelling massive production gains across all unconventional plays in North America.

As operators see their breakeven well costs decline, they continue to analyze the contributing factors that impact production optimization and which design and completion methods create the most value. Many operators and service providers are finding that value lies within the massive amounts of data their operations produce. Subsequently, many are also faced with the challenge of how best to leverage that data, and, specifically, how to make well design data meaningful.

"This process of digitalization and collation is imperative if we are to efficiently and effectively embrace increasing subsurface complexity, and will help facilitate more effective modeling and management of these complexities across the full E&P life cycle," Gabriela Morales, senior product specialist for Halliburton Landmark, wrote in a company editorial note titled "Facing up to New Realities," which focuses on addressing challenges in the well construction life cycle.

Operators are faced with a dizzying array of data sources—completions operations, wellhead information, public data, sensor data, reservoir and production information—which provide opportunities for companies to detect patterns that can be used to make better informed decisions and develop key performance indicators when designing wells. Simply put, operators must make key decisions that affect their bottom line on how to put that data into action.

Optimizing frack operations

Service providers both large and small have entered the Big Data analytics space in the industry and provide a wide variation of systems and tools. These companies offer recommendations on completions and design components such as chemical and fluid dynamics, mud motor parameters, collaborative well planning, ideal proppant loading and feasible lateral lengths.

ConocoPhillips initiated a Big Data analytics approach in its Eagle Ford operations, which it later pushed out to its Rockies business unit, then Midcontinent and later to the U.K., Australia and Norway.

"[Data analytics is] helping us optimize on a day-to-day level for frack operations, trying to make sure we have consistency as far as our pressures," said Justin Hammond, ConocoPhillips senior completions engineer for its Rockies business unit. "We're also doing the same thing on coiled tubing. For coiled tubing, there is a performance aspect, but there's also risk mitigation. When we don't perform well with coiled tubing, it costs us a lot of upsets of more than $1 million. Data analytics has helped throttle back the incidents we've had over the past couple of years."

Hammond said leveraging an analytics approach to well designs serves as collaboration between the company's completion designs and the reservoir performance of its wells.

"We can apply multivariate analysis and bigger data applications to try to find the best completion design," he said. "Right now we're looking at situations where historically we've always wanted to do bigger and bigger completions, trying to produce higher IP wells, but now we're able to look at that from a cost of supply perspective and try to find the optimal value instead of just the largest production. Bigger is not necessarily better for completions operations and production."

Enabling informed decisions

Systems like FracStream, developed by ReStream Solutions, integrate into hydraulic fracturing operations by analyzing and making real-time recommendations regarding the desired chemical and operational performance specifications to the operator's well design.

The system analyzes onsite fluid chemistry and pressure pumping equipment data using relevant datapoints to characterize the real-time status of the process fluids and operations. That information allows real-time recommendations that enable quick adjustments to controls to achieve the targeted fluid specifications.

"As it pertains to the operator, first and foremost one of the things they want to know is how their reservoir is responding to the completions activity that is happening on the surface," said Billy Roberts, president and CEO of ReStream Solutions. "They want to know what their data trail is and what the life cycle of the fluid chemistry is and what the rheology is as it relates to the equipment operations and through the length of the frack."

Roberts said that information allows operators to determine if the service provider is achieving previously determined key performance indicators and whether the established fracture models are holding up to the scrutiny of what the fracture data are indicating.

"At the end of the day, what they want is not only better control around the frack and predictability, but the ability to leverage that dataset that comes off the frack to make better decisions in the future," he said.

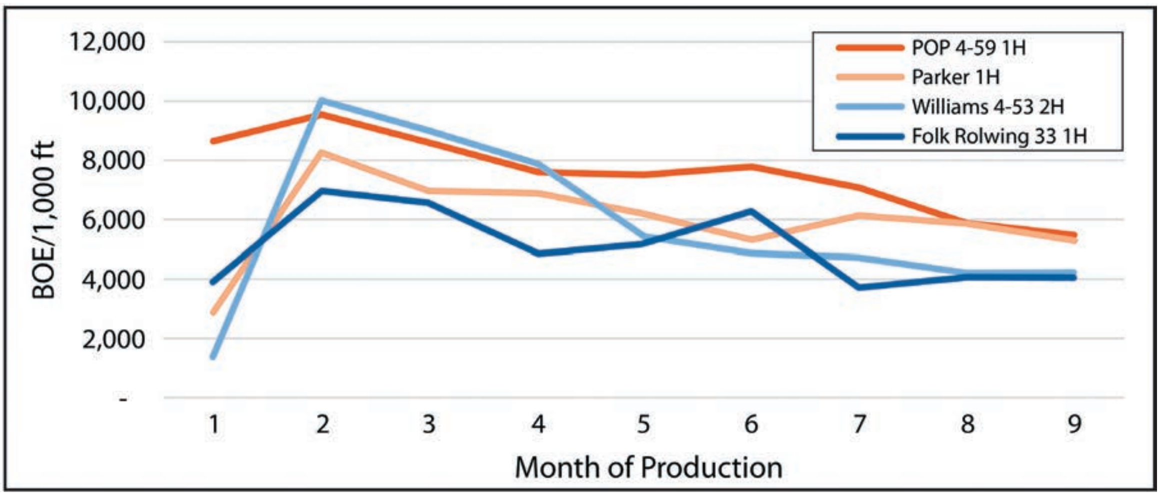
Data acquired through the analysis of fluid chemistry, rheology, equipment operations, pressure pumping units, pressure and flow rates combine to build a comprehensive framework for ReStream's systems.

"That [framework] allows us to make those datasets actionable," Roberts said. "We can collect all of this data and perform some number-crunching and identify potential problems."

Specialized well designs

Silverback Exploration recently applied C&J Energy Services' LateralScience system in the Permian Basin. The LateralScience application models the efficiencies of various drilling conditions to normalize mechanical-specific energy (MSE) results across a lateral, which results in the development of stage-specific treatment designs. Additionally, the process interprets drilling data to help guide the placement of stages and perforation clusters to mitigate the negative impact of lateral heterogeneity along the wellbore, according to C&J.

In 2016 Silverback Exploration held 35,500 acres in Reeves County, Texas, and, according to C&J, the company had already drilled two Upper Wolfcamp A wells that were optimized using sonic data. Each of the wells had oil IP 30 rates of more than 600 bbl/d, and were considered successful wells by the operator. C&J reported in a case study that Silverback Exploration learned of the LateralScience process prior to completing its third well. After applying the system, Silverback Exploration's third Upper Wolfcamp A well achieved significantly better oil IP 30 results of more than 900 bbl/d, according to C&J. As a result,



The chart features a comparison of four Silverback Exploration wells in the Upper Wolfcamp A zone of normalized total production. Wells designed with the LateralScience system are shown in orange, and those using sonic data are shown in blue. *(Data courtesy of C&J Energy Services)*

Silverback Exploration drilled three additional wells, with two in the Upper Wolfcamp A.

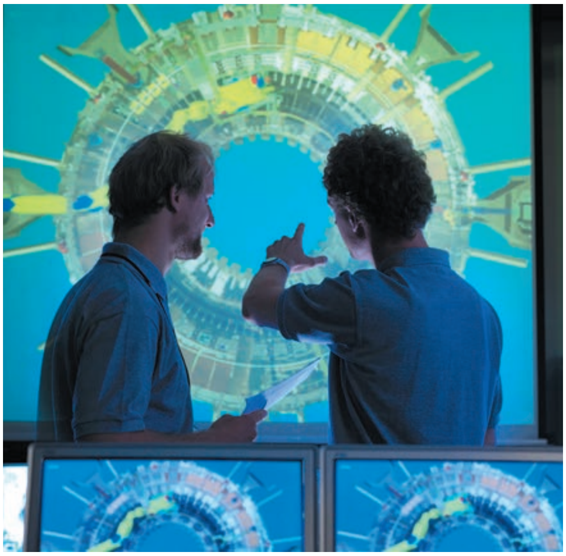
C&J reported that the LateralScience wells outperformed Silverback's two sonic wells by an average of 25% in the first nine months, with oil IP 30 results averaging more than 1,000 bbl/d. The production rate was achieved using 100-ft stage lengths and between four to six clusters per stage, depending on the MSE hardness index, C&J stated.

Silverback eventually sold its acreage position to another operator, which subsequently drilled three new Upper Wolfcamp A wells on that acreage. According to C&J, the new operator's wells were completed using a geometric design with constant stage lengths and increased clusters per stage from three stages to 15 stages.

"This provided an opportunity to evaluate the optimized LateralScience five-cluster design versus the geometric 15-cluster design," C&J reported in its study. "After a short time, both LateralScience wells significantly outperformed the best 15-cluster geometric and sonic-based designs."

Designing benchmark wells

Baker Hughes, a GE company (BHGE), applies analytics to create benchmark wells with data it acquires from the varying components of an operator's existing wells. Kishore Sundararajan, president of engineering and product management for BHGE's oilfield services division, provided an example of an analysis of 30 wells and how the data the wells provide can be modeled to create a benchmark well for an operator to follow.



BHGE creates benchmark well designs by analyzing the different components of previously designed wells. *(Photo courtesy of BHGE)*

"We have the data from the wells," he said. "We know what was used to drill the well—the fluids, the rig, the rig operator, all of that data. If those 30 wells are on, say, 5,000-ft laterals, then we can break down the wellbore quality and ROP information by formation, and even within the formation we can analyze 20-ft segments. Now we have 30 wells in which we can compare lithology, formation, fluids, along with ROP and quality for that segment."

That information, Sundararajan said, allows BHGE to know which segment of which well was drilled and completed the best for that formation.

"I can thread together the best pieces of the 30 wells and build a well in theory, meaning that's the benchmark well we can build if you put all of your best practices to work," he said.

Sundararajan said BHGE is in the midst of a project with an operator that focuses on offset well analysis with the goal to implement better completion designs.

"We are looking at wells that have been drilled and completed in a new field and identifying what completions work best for that producing well," he said. "It's an engagement to show them we can use Big Data to actually select better completions, not only design better completions."

Intelligent logistics

Halliburton Landmark's Well Construction 4.0 Digital Well Program utilizes a digital twin concept in well development, a system that digitally replicates and models an operator's physical assets, leverages data and inputs from modeling and upstream operations, and creates a continuous loop between the physical and digital worlds. The system, according to Landmark, identifies an efficient way to maintain the drilling process that, in turn, enables key decisions during planning and, more critically, live drilling.

"In addition to the pre-existing subsurface data and historical information, all surface equipment, downhole and rig data are fed to Landmark's system to continuously optimize and solve user-defined objective functions subject to physical, safety and economic constraints," said Olivier Germain, director of industry solutions at Halliburton Landmark.

Lapi Dixit, Halliburton's chief digital officer, said the company is designing a system that leverages machine learning and advanced analytics for well construction that includes automating and shortening the life cycle for well placement, design and execution.

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Hexion's PropShield™ proppant flowback control additive was developed specifically for uncoated frac sand completions. This unique solution is applied at the blender tub on location using a standard liquid additive pump. No job design changes are required. In the Permian Basin, it has reduced proppant flowback by more than 80% compared to offset wells.

"We were very pleased with the results and will continue to evaluate the PropShield additive in various areas across our acreage."

- Centennial Resource Development, Inc.

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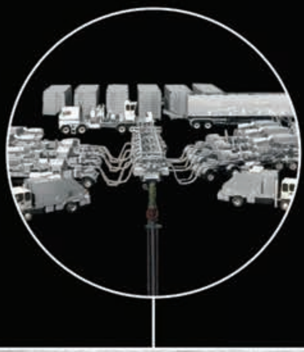

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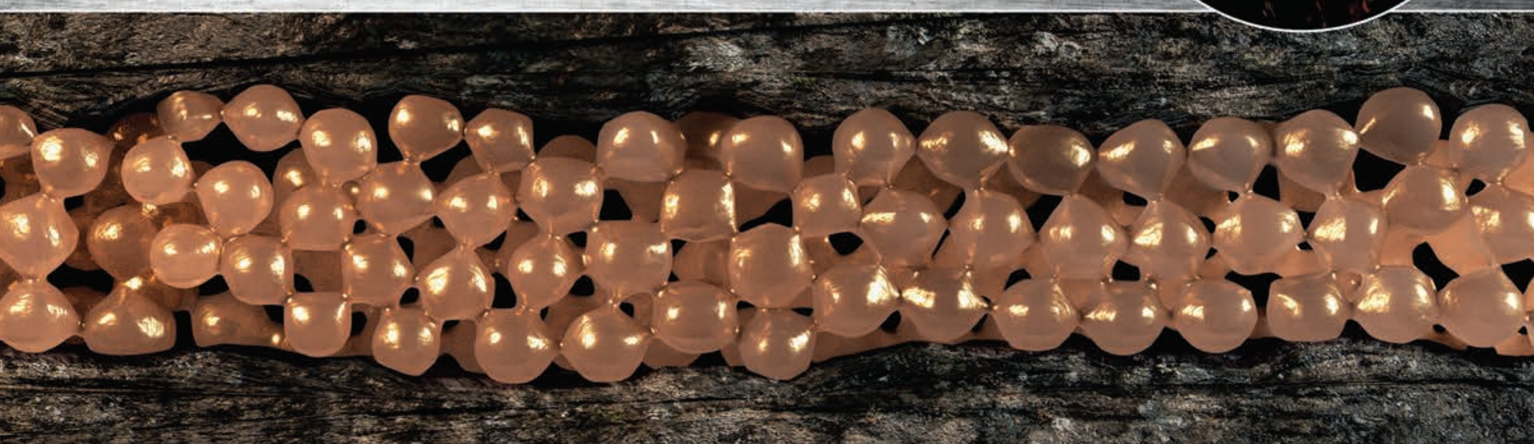


HEXION™

Responsible Chemistry

Dixit provided an example of how Halliburton uses data from offset wells.

"We don't need to repeat the same processes if we have a good enough idea—based on the offset well analysis—what the design is going to be section by section," he said. "What we can [analyze] for time, depth, cost, risk—all of those elements—we can auto-populate those designs and use machine learning [to automate the design and development of the well]."

Halliburton's DecisionSpace platform provides the integration and foundation for the Digital Well Program, and was recently applied by an operator in the Marcellus Shale. According to a Halliburton case history, the operator needed to quickly choose drilling locations in more than 450,000 acres of treacherous terrain. The task included optimizing the use of slots within pads, increasing lateral length while decreasing the number of pads and identifying sweet spots for priority drilling.

The Halliburton team used a 3-D earth model and a well-planning workflow to optimize drilling locations, lateral length and well orientation. The operation resulted in $45 million in savings in pad construction while the operator gained nearly 2 million ft of lateral length in fracturing operations. Halliburton reported the number of drilling days was reduced by more than 520 days, saving the operator more than $25 million.

Understanding fractures

Reveal Energy Services applies sensor data acquired from pressure gauges and bridge plugs to build pressure-based fracture maps. Those data enable the gathering of hydraulic fracture geometries and cluster efficiencies.

Sudhendu Kashikar, CEO of Reveal Energy Services, said these fracture maps are the result of an approach using pressure data as the basis for completion design information. The fracture maps, which Kashikar said have been widely adopted throughout the industry, have been evaluated on thousands of fracture stages and can be part of an overall greater diagnostic data acquisition and analysis for understanding other completion design attributes. Those attributes include stage length, number of clusters, proppant loading and production.

"There could be a scenario where [an operator has] an increase in production but really doesn't know how that's impacting the fracture geometry," Kashikar said. "There is a case where, given a change in completion parameters, you could actually be getting smaller fractures. Instead of a 500-ft fracture, you're getting a 400-ft or 450-ft fracture, but still getting the same production because the underlying rock quality is slightly different. But if I don't measure the geometry, I have no way of knowing that. I have a correlation that shows me that a change in completion parameters gives me an increase in production, but I'm missing the link to the fracture geometry."

He said by having the link to fracture geometry, operators can determine if their well spacing is still accurate, and if it is possible to produce more hydrocarbons by changing the well spacing.

"So, the fracture geometry becomes one more parameter, an important one, that can bridge the gap between completion parameters and production," Kashikar said.

Reveal Energy Services' system also works to calculate a qualitative indicator of cluster efficiency, which Kashikar said can determine if a treatment in a particular well in a particular stage provides good fluid and cluster efficiency or poor efficiencies.

"Based on that, operators can make the decision to either change their cluster design or start using some diversion to improve their fluid distribution," he said. "Let's say an operator chooses to use a diversion technique to try and improve that fluid distribution. We can then analyze in near-real time whether that diverter drop has been effective at improving the fluid distribution. If it's not, they can try tweaking that design."

Kashikar said operators have the ability to change the quantity, the timing and the number of diverter drops to get rapid feedback on a stage-by-stage basis so by the time they frack one well, they have tested several different designs and found the one that consistently provides good cluster and fluid efficiencies.

"We have several operators now that are using that data to test and improve their design parameters in terms of diverter drops and the number of clusters," Kashikar said.

A holistic view

An emerging approach for well design includes analyzing the full life cycle of the process—Sundararajan likened it a doctor recommending and providing treatment for a lifelong patient from birth to death. Companies like Ayata and BHGE refer to the concept as taking a holistic approach to well designs.

Ayata's system combines data from geologic, geophysical, petrophysical, drilling, completions and production operations to produce a model that allows the user to instantaneously project production values.

Michael Smith-Palmer, director of strategic accounts for Ayata, said the company's software has been run on more than 14,000 shale wells in North

Reservoir mapping systems applied by BHGE detect downhole dynamic events and improve drilling and completion operations. *(Photo courtesy of BHGE)*

America. The program prescribes specific completion recipes and predicts corresponding production economics for wells. He said analyzing a wider array of data sources could result in increased production rates for operators.

"Historically, companies have focused on one or two datasets that affect production and optimizing within those smaller datasets," Smith-Palmer said. "Optimizing completion or drilling without taking a holistic view of all of the available data is definitely limiting the scale of improvement. More data inherently leads to larger gains because the solution considers more variables that affect production and cost performance."

Widespread adoption challenges

The claim has often been made that the oil and gas industry is notoriously slow to adopt new technologies, and it remains to be seen how widely Big Data analytics will be implemented across the industry despite early favorable results. Coherent data collection and normalizing data are significant barriers operators and service companies alike are working to overcome.

Dale Logan, senior vice president of marketing for C&J Services, said companies, especially larger ones with a track record of success, are often reluctant to shift away from operations that have so far proven successful.

"There are some operators, smaller companies, that are more likely to adopt [analytics]," he said. "They are the early adopters who are embracing the idea of doing this, trying to do something other than geometrically slicing and dicing up the wellbore. The bigger companies are coming around to it. They have had great success doing things the way they have been doing them."

Another challenge to successfully implementing analytics is collating a wide disparity of data types—well logs, borehole videos, drilling reports, seismic, core data, PDFs, texts—and from different sources into something easily consumable and actionable.

"Data gathering for each well from the client is a big challenge because different personnel have different types of data in any E&P company, which

ConocoPhillips first applied Big Data analytics to well designs in its Eagle Ford operations. *(Photo courtesy of ConocoPhillips)*

many people refer to as data silos," Smith-Palmer said. "Most of the time data is not all in one place. And, obviously, a lot of companies are hesitant to share data."

Dung Nguyen, staff drilling and completions analytics engineer for ConocoPhillips, said the company is working with service providers and fellow operators as part of the Operators Group for Data Quality to standardize some of the process and contract language used in the industry so that data can be more consistently processed.

"For data on our hydraulic fracturing operations, we work with our service companies to standardize the datasets we require from them," she said. "So, whenever one company calls it 'slurry rate,' it's always going to be slurry rate. So that way, we always have a consistent way of pulling the same data per vendor. All vendor naming standards are then converted to ConocoPhillips naming standards so we can then compare across vendors."

Nguyen said ConocoPhillips has met with other operators to address this challenge, with the goal to make data analytics processes easier for service providers.

"It makes it a lot harder for our vendors to meet requirements if they have 20 different standards from different operators they have to meet," she said. "But if we are being consistent on certain requirements, it makes it easier for our vendors to meet those needs, and they're not having to rebuild a new process for every single operator."

Dixit explained the benefits of building "architectural coherence" for an analytics system and how it creates a seamless process for those involved in building wells.

"Whether you brought data from your own data store, our data store, somebody else's data store or some back-filed system, our ability to consume that data and create an absolutely seamless method in putting that data together is important," he said. "So the person who was involved in exploration, the person who was involved in designing a well and executing a well have the same view of the same well at the same time." ■

Shale Bonanza Pinches Water and Sand

In-basin mines and area water banks relieve some strains, but long-term concerns remain.

By Gregory DL Morris
Contributing Editor

By the middle of 2018 Mammoth Energy Services expected to have completed all of its Wisconsin frack-sand expansion projects, taking total production to 4.4 million tons per year (mtpa). If all six of its pressure-pumping teams are in action—as they were at midyear with three in the Marcellus-Utica, two in the Scoop/Stack and one in the Permian—then they consume about half the new total sand production. Another 1.3 mtpa is sold to third parties on a contract basis, with the 700,000 tons/year moved on the spot market.

The growth has been remarkable over just about 18 months. At the start of 2017 Mammoth had total sand production of just 700,000 tons/year, and only three pressure-pumping crews. Today six crews have 50,000 hp at their disposal.

"We have differentiated ourselves from the pure-play pressure pumpers and sand suppliers," said Don Crist, director of investor relations for Mammoth. "We targeted sand as a necessary input, and we pride ourselves on security of supply. Last winter when there were serious logistics and supply problems with sand, all of our projects were kept supplied and completed their jobs on time."

According to several sources, the primary problem with deliveries of Northern White sand over the winter was not so much severe weather, although that was a factor. Mostly it was a shortage of locomotives and crews, especially on the Canadian National Railway, which operates the Wisconsin Central Railroad.

"That situation was better in June than it was in February or March," said Crist, "but it has not been fully resolved. There have also been delays with some of the in-basin mines coming into service in West Texas, but even when all that is resolved, there will still be the matter of availability of trucks and drivers, and congestion in the last mile."

The shortage of truck drivers is a long-standing nationwide issue that has affected all segments of the road-freight sector. Crist said Mammoth expanded its last-mile operations in 2017, and noted that every driver hauling water or oil is one not available to move sand.

Ironically, even with the driver shortage, there are traffic jams in the sparsely populated Permian that rival those in major metropolitan areas. "All the in-basin sand mines are within about 30 miles of each other," Crist said. "There are intersections where hundreds of trucks take hours to get through. And that is all trucks, sand, water, oil and rigs. The Scoop and Stack, closer to our base in Oklahoma City, is not so congested, but it is still a challenge to find trucks and drivers."

Sand types are shifting as much as sources and logistics. Frack sand sizes run from coarse, 20/40 to 30/50, to finer 40/70, and then 100 mesh. When gel fractures were prevalent, the thicker matrix could support coarser sand. With the industry standard shifting to slick water, coarse grains won't stay in suspension.

"For 100 mesh, it really doesn't matter if it is Northern White or in-basin, because it is basically just sandblasting the formation," Crist said. "Most 40/70 is Northern White, and that is most in demand for slick water. The 30/50 is also Northern White. That will work about half the time in slick water. In many of our jobs, about a quarter of the initial stage is 100 mesh to scour the formation and make the breaks. After that comes the 40/70, which is used to prop the formation open."

The Taylor Sand subsidiary processing facility is in Taylor, Wisc. *(Photo courtesy of Mammoth Energy Services)*

Laterals doubled, stages halved

In pressure pumping Crist noted that as lateral lengths have doubled, the average length of stages has diminished by more than half from a norm of 400 ft to 500 ft per stage, to 150 ft to 200 ft per stage. As recently as 2015 a big frack would have been considered 270,000 lb of sand per stage. Today the norm is twice that, 500,000 lb or 550,000 lb of sand per stage. Anything much beyond that now counts as a big frack.

Typical pressures, however, have been little changed, although they vary by basin. In the Scoop/Stack typical pressures run 7,000 psi to 10,000 psi, to as much as 12,000 psi, with deeper formations requiring greater pressure. The Utica generally requires high pressure, 11,000 psi to 12,000 psi.

There is not really an upper limit to pressure, Crist explained, only a matter of cost versus return. Pressure pumpers use a manifold, called a missile, to equalize pressure across a battery of pumps and the fluid downhole. Mammoth tends to use a 20-port missile, with 18 ports in active service and two for flexibility.

It is uncommon for a sector to see broad growth and a plethora of new entries, along with consolidation at the same time. But that is what 2018 looks like in the North American frack sand business. The most notable combination was completed June 1, when two of the larger suppliers, Unimin and Fairmont Santrol combined, with the new entity now called Covia. A month before U.S. Silica bought EP Minerals.

Most of those companies have their production concentrated in and around the northern Midwest, which has led to long supply chains and some logistics problems getting that sand to the Permian and Eagle Ford. As a result, quite a few in-basin mines have been coming into service. Some of the big companies are involved, but many of the new pits are ventures, and most have experienced delays in coming into service.

The in-basin trend is expanding to other shale plays, said Todd Bush, founder of consultancy Energent Group. "We are tracking eight mines being developed in the Eagle Ford, with more expected. We are tracking nine in Oklahoma, with more expected." He added that U.S. Silica and Covia already have mines in Oklahoma, but that those are not as close to the most active drilling areas of the Scoop/Stack.

In effect the boom in new sand operations is akin to growth in other sectors of the industry, upstream and midstream. The majors certainly could fund new facilities, and some have. But in general the big boys in all segments let the venture-capital folks take the lead, take the lumps and then buy into the survivors. The early bird may get the worm, but the second mouse gets the cheese.

"In the next 12 to 18 months we will see a host of consolidation," said Bush. "The in-basin mines that are being built now are likely to have shorter ramp-up periods than the ones in the Permian, but there are still delays to be expected. Even mines that were active have had delays in expansions. That will continue to be a challenge but we do expect it to get smoother."

Grains of truth

Frack sand is graded by grain size, and also as semi-processed or fully processed, known as wet and dry. Wet sand is screened for size and piled on the ground. When those piles are run through a heater and further filtered, the result is dry sand.

Bush noted that another reason the majors have not rushed to in-basin sand is that the needs of operators are changing. "The move to the fine 100-mesh sand is where many of the new mines have opened," he said. "The jury is still out on diminished well performance with in-basin sand, but the preliminary studies we have seen seem to show not much change."

Farther out, there may be some risk to the incumbent suppliers. "Many operators have long-term contracts for sand supply to lock in prices," Bush added. "But the big suppliers of Northern White sand may be at risk in delivering to Oklahoma or the Permian as a result of in-basin supply."

With any booming commodity business there is the chance of tipping into oversupply. That said, longer laterals and heavier sand loads would seem to mitigate that risk for sand, at least this year. "The biggest load we have seen so far is a well that used 57 million pounds of sand," Bush said. "EOG has built something of a reputation for heavy sand in the Eagle Ford. We know of several where 30 million pounds were used."

Commonly a frack will consume 2,200 lb of sand per lateral foot, which is 330,000 lb in a 150-ft stage and 440,000 lb in a 200-ft stage. Both get to about 22 million pounds per well. What qualifies as a "big frack" keeps changing, but the upper echelon in 2018 is around 4,500 lb per lateral foot.

"Operators are getting a handle on the drilling factory," said Bush. "They are trying to develop a systematic approach to multiwell, multipad development."

By the end of the third quarter Sourcewater expects to launch publication of water and saltwater disposal benchmark prices, reflecting "the actual prices paid at the receiving pit for water or at the tank battery for disposal," said Josh Adler, founding CEO. The benchmarks will be adjusted for location water type, logistics type and volume.

Earlier this year the company released its satellite imagery analytics of the Permian Basin. That identifies all frack-water impoundments, how much water each holds, the type of water, and the associated surface owner and operator for each. The satellite scans are updated monthly, working toward weekly updates that will identify new pit and well-pad construction before permits are reported by the Railroad Commission of Texas.

Adler noted that the sudden distress about availability of sand has overshadowed the existing and increasing concern about water, especially disposal. "In two years no one will be concerned with sand," he said. "By 2019 or 2020 there could be an oversupply. The long-term picture for sand is like the long-term picture for pipeline capacity. There will be under- and oversupply cycles. Those will come and go. But the long-term constraint on energy development is water, particularly disposal capacity."

The danger is real

Produced water for fracturing is not a material supply or technical question but a logistical and regulatory challenge. "There is plenty of produced water if it can get to where it is needed at the right time," Adler said. "Water midstream networks will move produced water to both new completions and disposals, switching between those alternatives based on opportunistic timing and economic tradeoffs. The water midstream players will trade peak flows and excess capacity with each other through interconnections on forward contracts, running water in both directions."

Many operators are shifting to brackish water from freshwater, said Adler. "Those aquifers are less well understood," he noted. "They are not used for anything else, so there is no competition for that water. But they are deeper than freshwater aquifers, so they are more expensive to drill, and they seem to recharge more slowly and deplete more quickly. Brackish water use is a bridge to universal produced water recycling."

The one place where there is a finite capacity is saltwater injection wells, Adler explained. "If you overpressurize and destroy the rock, that causes the water to slosh around. Then when you drill into the oil formation below, the water rushes down into the well and kills the economics. You end up reproducing water."

The danger is real, Adler warns. "No one knows the real capacity for the disposal wells, but there is a limit. At some point treatment for beneficial reuse beyond new completions becomes increasingly viable as disposal becomes increasingly tight, but no one knows when that will happen."

Early in May H_2O Midstream completed the first commercial, truck-free, produced-water storage and disposal hub in Texas. The Howard County hub comprises two 500,000-bbl ponds connected to a network of 10 disposal wells totaling 220,000 bbl/d of capacity via a pipeline network of more than 130 miles. There is also a new 35,000 bbl/d, deep-Ellenberger disposal well.

Through its pipeline, storage and disposal network, H_2O Midstream provides produced-water gathering, disposal, transportation, reuse, storage/banking, peak-shaving and forward sales. The company said its system has the potential to remove more than 650,000 truckloads per year of produced water from Texas roads.

"We now have seven customers on the system," said Jim Summers, CEO, "all served by pipe. The hub was designed for reliability and peak management, as well as reuse, and we have been pleasantly surprised at the level of local interest."

The next step will be expanding the pipe connections. That will be in every direction, but primarily north and west. "We expect volumes to increase, and can add new capacity," Summers said. "We are also looking actively at new facilities in other geographies. There will definitely be further growth in Howard County, and we needed the first year of operational experience. That has been invaluable as we are doing something new here, managing multiple operators on a commercial pipeline system."

Big fracks get bigger

Like many of his colleagues in water management, Summers has watched the issue of frack sand supply erupt into the industry's consciousness. "There are fundamentals driving demand for both sand and water," he said. "The shift from conventional to unconventional and from gel fracks to slick water, the longer laterals; all those are creating opportunities but also creating new constraints."

Summers spent some of his career in biomass, so he understands the different logistics for solids as opposed to fluids—gas and liquids. "Still water and sand are both commodities, with advantages in economies of scale. And the fundamentals are driving water infrastructure more and more."

"We are very busy," said Michael Henry, global production enhancement operations manager at Halliburton, "activity is picking up this year." There is not really any mechanical or material limit to fracking pressure, he noted; the control is the return on costs for higher pressures, and volumes of sand and water. "We usually operate up to 15,000 psi, but can go to 20,000. Jobs in the Eagle Ford run 10,000 to 11,000 psi, while jobs in the Bakken run more to 7,000 psi."

Thirty to 50 stages per well is not uncommon, Henry added, "and we are seeing more and more wells per pad. What counts as 'big frack' is getting to 600,000 pounds of sand per stage."

Sand demand, then, becomes paramount. "Part of that is change in mesh sizes and percentages," said Henry. "There were also a lot of weather delays, as well

A Stingray pressure pumping subsidiary crew is on site in Ohio. *(Photo courtesy of Mammoth Energy Services)*

as other demands on the railroads. We are probably coming out of the major concerns for sand logistics, but there are still some local concerns. There are a lot of plans for local sand, but those are taking longer than anticipated. Not permitting issues as far as I have heard, just delays in construction."

Water has been a concern for longer, and it remains so. "That is true no matter what the area," Henry said. "Produced water is definitely of interest in many areas for use in fracking but load recovery remains highly variable well to well. The operator typically handles the water logistics, but we can customize the job based on the type of water available. Fluid systems are becoming less complex, so it's mostly a matter of adjusting the recipe for the raw water. These days we can make any type of water work with proper prejob testing."

The maturation of techniques in diversion and refracturing are becoming a bigger part of what Henry's group does. "We are also excited about how nanotechnology can improve recovery," he added. "Data analytics will increase decision-making speed. And I have been fascinated by fiber optics. Together these three advancements, nanotech, data analytics and fiber optics, will make for better decision-making."

None of that changes the physics of water, sand and rock. "As pressure increases, and we are pumping more material, reliability will remain a high priority," said Henry.

A discharge idea resurfaces

"While we do have some mobile assets, called Shaleflow, our focus is on fixed water-treatment facilities," said James Welch, director of business development for industrial projects for Veolia. "Our strength is in not only reuse standards—removal of solids, iron, bacteria, sulfate and so forth—but primarily in surface discharge to National Pollutant Discharge Elimination System standards."

That approach, although more expensive and regulated than deep injection, is coming to the fore in regions where disposal wells are becoming limited. "Injection is very much a concern in the Delaware Basin," Welch said. "Produced water will exceed the capacity to dispose of it in saltwater wells in the not too distant future. Seismicity will further curtail injection capacity. Producers will want to reconsider surface discharge. That could be to the Pecos River, for example, or even for irrigation—although that is more complicated."

Veolia is already operating several permanent facilities in California that treat produced water and discharge it into aquifers and rivers. Another such treatment plant is being completed in the Piceance Basin in Colorado. It is expected to be in service by the end of the third quarter of 2018.

To be sure, cleaning and treating produced water to surface-discharge standards remains expensive, relative to injection or recycling. Welch expects that as Veolia and other firms increase scale and efficiency, costs will decline. At the same time, the physical limits of deep disposal, not just formation capacity itself, but transportation, will increase costs and reduce availability.

Simultaneously, producers are improving reuse in some cases to eliminate discharge. The fourth leg of the water management table is water collection and redistribution, or multiproducer water banks. The first of those in the Permian came into service in Howard County in May.

"Operators want balance of risks and resources," Welch said. "And they are embracing all four options. We do not handle any logistics or impoundments; if a midstream water company needed support for a multiproducer system, we would be able to do the treating and make quality and quantity guarantees."

ChemTerra Innovations was created as a discrete operation within Trican Well Service at the end of 2017 to sustain the North American growth of its oilfield-chemicals business even as the parent well-service business consolidated to exclusively Canadian operations. In its first half year the new kid on the block has thrived.

"We had been developing proppant coatings for 20 years," said Natasha Kostenuk, general manager, "and running them exclusively through our own pumps. When the firm consolidated in response to the industry downturn, we needed a way to sell to other companies. Now that business is growing again, most of our business is in-house, but outside sales continue to grow."

From dust to downhole

The most established segment for ChemTerra is in proppant coating to reduce dust during transportation and into use. That grew into other coatings that are intended to bring sand close to the performance level of ceramic proppants. Most recently the company has developed surfactants to enhance oil recovery.

"We started with coatings for transportation," said Bill O'Neil, director of research and development. "The push recently has been coatings that improve the hydrocarbon-conductivity of the proppant. It permanently upgrades in-basin sand to the

Logistics Strategies are Unlocking Operational Value

Portable, nimble and maneuverable mobile frack sand containers have begun to replace the incumbent technology.

By Matt Oehler, Brian Dorfman and **Kevin Fisher**
PropX

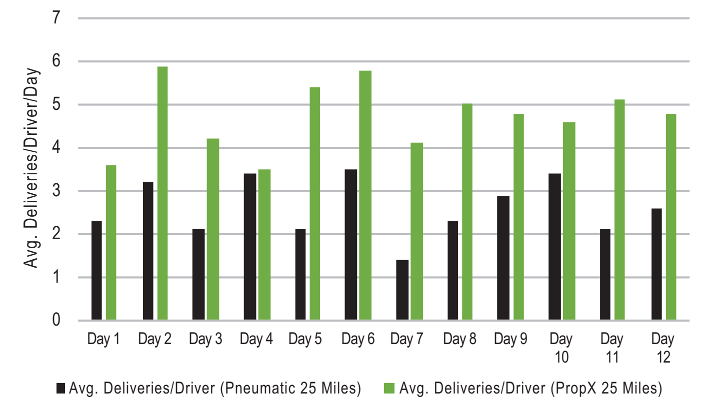
The incumbent method of storing fixed amounts of sand at a well site includes the use of several storage bins, which are supplied by pneumatic trailers each holding 45,000 lb of sand. This sand supply method worked well for decades when a "mega" frack was around 1 MMlb of sand total per well. As modern fracturing has become more sand intensive with horizontal wells averaging more than 12 MMlb and frack crews often pumping in excess of 4 MMlb of sand per day, the old method of replenishing the large, entrenched storage bins simply cannot efficiently sustain the frack beast. A mobile container technology provides the flexibility to address today's complex supply chain.

Contrasting container efficiency is straight forward. PropX containers provide an elastic buffer of supply at multiple points along the supply chain. Choke points at the well site can be dealt with by short, predictable 10-minute or less drop-off times. Trucks do not wait because they are not constrained by a maximum storage level being exceeded or by protracted unload times. They are in and out swiftly during the moment of greatest need. Distribution depots can be placed in strategic locations or at the rail terminal to reduce the risk of demurrage not only at the well site but also at the rail terminal or mine. Inventory can flex up and down as needed, and quick infusions of emergency supply at the well site are now a realistic possibility. In-basin depots can be tapped and stocked during the inevitable ebb-and-flow activity swings that happen during large, complex shale completions.

Keeping the frack operation consistently supplied with the sand to meet its daily consumption is a primary goal. The PropX mobile container operation works to meet this objective. The company's two-box enables the user to haul from 42,000 lb to 58,000 lb per trip. Light-weight trailer designs paired with day cab tractors provide the opportunity to maximize the volume of sand on each delivery based on localized department of transportation allowances.

The company works closely with trucking providers to maximize the number of deliveries per driving shift. Figure 1 offers an example of 28 trucks delivered 799 loads of sand from a transload in West Texas to a nearby pad site in seven days. The drivers averaged 4.1 loads per shift, which equates to a delivery every 12.6 minutes. This example further demonstrates the value of reducing offload time on site. Any pneumatic system would require at least 35 trucks to deliver the same 799 loads during that same period, which results in a 20% efficiency and utilization gain.

Figure 1: Average Deliveries/Driver/Day (Pneumatic vs. PropX)



(Data courtesy of PropX)

Although obstacles are expected in the oil field, disruptions can arise that cause the supply chain to react and shift sand deliveries to overcome short-term challenges. PropX provides flexible, in-basin temporary storage and forward staging to overcome these challenges.

Forward staging moves an ever-changing portion of the sand supply from the bottlenecks to intermediate depots where it can be delivered and accounted for with swift precision. This enables trucking resources to remain flexible and utilized at full capacity, even during the inevitable operational starts and stops. Adding additional storage at the pad site may yield a similar result in the short term, but it limits that benefit to that single pad site rather than to the entire supply ecosystem.

Forward staging and intrinsic product mobility may enable multiple frack operations to continue during a challenging period while proactively preparing for the next unexpected disruption. ■

performance of Northern White. That has become very important in the Permian where there are a few dozen Tier-2 or even Tier-3 sand producers trying to upgrade their operations."

ChemTerra manufactures some of its own coatings and chemicals, and licenses some manufacturing to contract formulators.

"EOR is usually considered secondary or tertiary recovery," O'Neil said, "but we have published papers and received patents for chemistry that turns frack water into the equivalent of a waterflood. We are calling it 'post-frack EOR.' In proppants, I can't tell you the last time we pumped ceramics in the U.S. or in Canada."

Jobs with more than 500,000 lb of sand per stage sand and/or 500,000 gal of water per stage are considered to be big and usually operate at treating pressures above 10,000 psi to 11,000 psi, said Jesse Lee, chemistry portfolio manager for well services at Schlumberger. But economy and effectiveness are the goals, not sheer size.

"Our offering is focused on lessening the amount of expenditures regarding water management," he said. "We have fracturing fluid technology that has enhanced compatibility with produced water, which subsequently reduces the needs for water treatment, transportation and disposal. Consultation includes optimizing fluid formulation, inorganic-scale minimization, treatment design and execution."

The trend to regional water banks is "entirely technical and economical feasible," Lee added. "The degree of adaptation will mainly depend on the availability of water. If it becomes scarce due to high fracturing activity, then the model where one well's produced water is the frack water for another well will become highly desirable."

Schlumberger has developed frack fluid technology, called X-Water, which has an integrated water-flexible fluid delivery service. Lee noted, "It is relatively insensitive to water quality; therefore, we do not foresee any major changes in fluid recipes. However, one might need to incorporate additional scale inhibitor to prevent inorganic scale formation." ■

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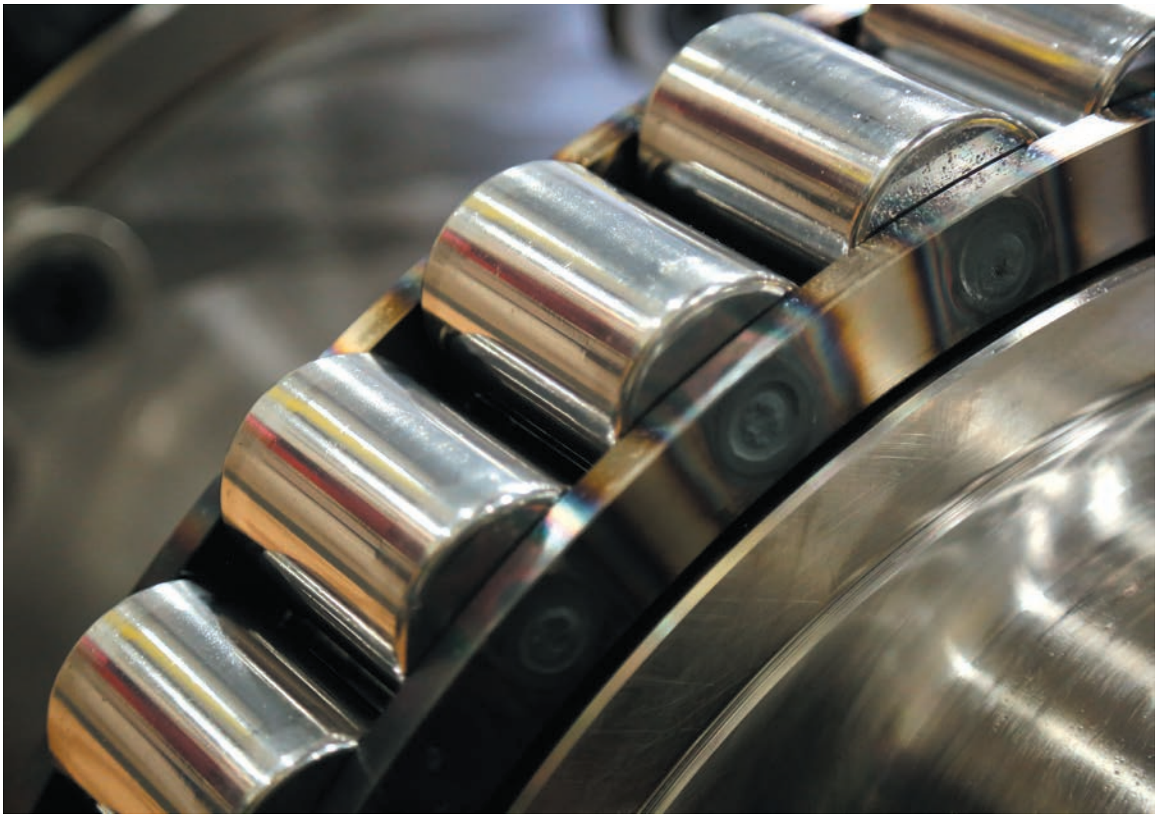
Evolving to Operate in Harsh, High-Pressure Environments

A new pump designed specifically for use in highly challenging formations for extended periods of time delivers success in the Montney Shale.

By Zachery Kokel and **Craig Schroh**
Weir Oil & Gas

When the use of modern-day hydraulic fracturing began its upward trajectory in the 1990s in response to cripplingly high oil prices, field operations and existing equipment requirements were based on intermittent, lighter-duty use. Operators ran hydraulic fracturing equipment for a few hours a day, which is what all equipment was designed to handle.

Today, those operating environments have shifted dramatically. To meet expanded needs, operators



These roller bearings on the QEM 3000 pump follow 2,700 hours of demanding service. *(Photo courtesy of Weir Oil & Gas)*

are subjecting their intermittent-duty legacy pumps to 24/7 performance in the field in harsher environments. Additionally, more sand is running those pumps in conditions that are not ideal for the equipment's design. Legacy fracture pumps simply have not been designed to run at full rod load under such relentless duty cycles.

Typical intermittent-duty pumps are commonly rebuilt before the 3,000-hour mark. Rebuilding these pumps is an expensive proposition. In addition to the costs associated with rebuilding the pump, operators often experience a few weeks of downtime during this service period, requiring the carrying of additional capital costs by having more pumps in a fleet as backup, as well as more fleets than true uptime demand requires. This cuts into operators' bottom lines, creating additional financial pressures in a notoriously tight market.

Case study

One Canadian operator running equipment in the Duvernay and Montney formations—known to be especially unforgiving due to high pressures and extreme temperatures—had been experiencing the traditional time frame for rebuilding its traditional pumps. With rebuilds averaging CAD 60,000 to CAD 100,000, the expense of such maintenance with the associated downtime was adding up quickly for its fleet of pumps. The operator decided to deploy a new pump specifically designed for use in high pressure for extended operating periods, the Weir SPM QEM 3000 Frac Pump.

Recognizing that the demands placed on fracturing pumps have changed and some operators are moving to running longer hours in harsher regions, Weir re-engineered the QEM 3000 from the ground up. Designed to be a high-performance pump for high-pressure environments, the pump provides operators the ability to run at a sustained 275,000-lb rod load for extended operations.

The operator had high expectations for the pump based on its initial testing. While the traditional fracturing pump development process typically may test up to one million cycles, Weir had completed an endurance test of its beta SPM QEM 3000 in its Fort Worth Research & Development Center lasting three times longer than other pumps in the company's history. While legacy pumps perform well in basins with lower pressures and rod load, the QEM is ideal for the harshest environmental conditions and pressure requirements. Additionally, it will increase uptime and reduce total cost of ownership, fleet size and the number of fleets required in any basin.

The pump features a dual-pressure lubrication system, multistage onboard filtration and enhanced structural rigidity. It also offers the largest roller bearings currently available in the industry as well as other oversized components to more efficiently distribute load stress across greater surface areas. These enhancements were specifically designed to address the most common causes of pump failure.

Results

The Canadian operator deployed a fleet of 12 SPM QEM 3000 pumps and operated them 16 hours to 18 hours per day in temperatures averaging 20 F to 23 F at a fracture pressure of 10,500 psi to 13,000 psi. The average rod load was 206,250 psi to 233,750 psi with a 5-in. plunger and a flow rate of 264 gpm to 343 gpm.

Following relentless operating conditions, the roller bearings looked new at the 3,200-hour inspection and the shell bearings were barely broken in. Other wear parts that would normally require replacement, such as guide sleeves, showed insignificant

The crank assembly from the QEM 3000 shows minimal wear following 2,700 hours of service.
(Photo courtesy of Weir Oil & Gas)

wear and did not require replacement. The onboard filtration system delivered clean oil to enhance bearing life through optimized control.

With a traditional fracturing pump under similar conditions, the operator would have already rebuilt its fleet of pumps once, and the fleet would be on its second life. However, as the SPM QEM 3000 is fit for purpose in high-pressure operations with longer horizontals, it is poised to effectively at least double the lifespan of traditional fracturing pumps in such environments, as the equipment looks and performs like new at 3,200 hours. This saved the operator CAD 75,000 per pump, approximately CAD 900,000, not including downtime.

With the QEM 3000 pumps in use, the operator is now able to run only two QEMs for every three legacy pumps in these particular basins due to the QEMs being specifically engineered to meet demanding requirements. While legacy pumps run a 4.5-in. plunger, the QEM can run a 5-in. plunger because of the rod load. The operator noticed that the QEM pumps run smoothly and feel safe, even at the higher rod load and horsepower. The operator is approaching using 80% of available kilowatts, helping to achieve greater efficiency. Additionally, the packing lasts up to three times longer because of improved alignment and stiffness of the frame. Having this kind of capacity and performance enables the operator to respond to market demands quickly, resulting in incremental and new revenue opportunities.

The SPM QEM 3000 continues to yield unsurpassed results and savings in the field for this operator, looking and performing like new after more than 3,200 hours of field-proven use in extreme conditions in the winter months in the Duvernay and Montney shale plays. Given its current performance, it is expected to extend maintenance cycles by a factor of three as compared to what the operator achieved in similar service conditions previously. These enhancements dramatically affect their bottom line, expanding lifespan to improve uptime and productivity, all while reducing maintenance costs and lowering total cost of ownership by at least 17%. Operators running a QEM pump in similar conditions as the Duvernay and Montney formations could expect greater than 200% increase in pump life. ■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Pressure Data Analysis Guides Operators to Better Completion Decisions

A new physics-based method provides nonintrusive pressure data acquisition and analysis to develop accurate pressure-based fracture maps.

By Sudhendu Kashikar
Reveal Energy Services

As oil and gas operators continue to streamline operations in the office and the field, their reliance on data for uncovering efficiency levers is becoming permanent. The gold in the data is worth mining, so industry generally is looking at data and analytics in new ways to enhance decision-making about operations, sales, customer service and IT, for example.

Data can be statistics-based or physics-based. The statistics-based method, also known as Big Data analytics, is interesting for the oil field because the method offers insight into production performance. Operators are investigating this method to predict a new well's cumulative first-year production using a set of operational and completion characteristics such as lithology, well depth, stage length, fluid volume, proppant loading and cluster spacing.

A physics-based method includes fracture modeling and simulation of fluid flow in a network of induced and natural fracture systems coupled with geomechanics. Calibration of these models requires measurements of the fracture geometry created through hydraulic fracturing.

Acquiring fracture geometry for a meaningful number of wells has been challenging because the older methods of data acquisition are complicated, intrusive and expensive. Overall, this older technology disrupts field operations, requires additional wellsite personnel and equipment, and is expensive to deploy.

Fracture geometry also has been missing from statistical data analytics for these same reasons. Including fracture geometry as a variable for statistical data analytics would improve the predictability of these models by linking the geometry of the created fractures to completion parameters and production.

A new technology has been developed specifically to work around all of these challenges, enabling operators to have a full view of the fracture geometry on every well. The theory of this new, physics-based method is nonintrusive pressure data acquisition and analysis. The simple, accurate, affordable pressure-based fracture map—with fracture geometry of half-length, height, azimuth and asymmetry—is guiding operators to make informed, better completion decisions.

Pressure-based fracture map

This new oilfield diagnostic application—the integrated modeling approach for geometric evaluation of fractures or IMAGE Frac technology—is field proven in more than 3,500 hydraulic fracturing stages throughout the U.S. and in Canada. The technology is based on the poroelastic pressure response that occurs during normal hydraulic fracturing of treatment wells. The pressure response is recorded by a surface pressure gauge from one or more monitor stages in wells adjacent to the treatment well, or what is described as the monitor well. These wells can be interchangeable.

After acquiring the pressure data in the monitor stages, poroelastic pressure responses must be differentiated from pressure responses caused by direct fluid communication or advective/diffusive fluid transport. Once identified, poroelastic signals can be used to estimate hydraulic fracture geometry by matching the observed responses in the monitor stages to a digital twin. The output, which is the fracture map, is the fracture dimensions of half-length, height, asymmetry and azimuth and how fast those dimensions grew.

Case study

An operator working in the Eagle Ford wanted to evaluate completion effectiveness in the Lower Eagle Ford (LEF) shale formation and to identify an appropriate completion strategy in the field. The LEF's physical and geomechanical properties vary significantly from east to west of the formation. Local variations in thickness, thermal maturity and pore pressure pose several challenges in designing a suitable fracture job.

The operator conducted a study comprising 14 wells across multiple pads. Pressure-based fracture maps were acquired on all 14 wells. A test matrix was developed to evaluate various completion parameters: fluid system, stage length, perforation clusters, fluid volume and proppant volume. These parameters were varied across the 14 wells and spread across the test pads to ensure good geologic and geomechanical sampling.

The operator's goal was to evaluate the effect of stage length, number of perforation clusters, fluid systems, proppant loading and total fluid volumes on the resulting fracture geometry and production. With the pressure-based fracture map, the operator identified the right completion strategy and well spacing.

Increasing stage length. Historically, the operator had used a 200-ft stage length with six clusters per stage. Based on the right completion strategy from the pressure-based fracture map, the operator made the informed, better decision to increase the stage length 50 ft to 250 ft with nine clusters per stage. The fluid and proppant volumes were adjusted to provide the same fluid and proppant per cluster. Three fluid systems were evaluated: the company's standard historical design, slickwater and a hybrid cross-linked gel system.

Reveal Energy Services' geoscientists and completion engineers computed fracture maps for all 14 wells and analyzed them to understand the importance of each completion parameter on the resulting fracture geometry.

Figure 1 shows the effect of changing the stage length from 200 ft to 250 ft for various fluid systems. The results show that the new design with longer stage length and nine clusters provided the same geometry, measured by fracture half-length, as the historical completion design for all three fluid systems. This resulted in a 20% reduction in the number of stages without compromising the effectiveness of the stimulation.

Fluid volumes. Three different fluid volumes were evaluated to determine the optimal fluid loading: 25 bbl/ft, 32 bbl/ft and 40 bbl/ft.

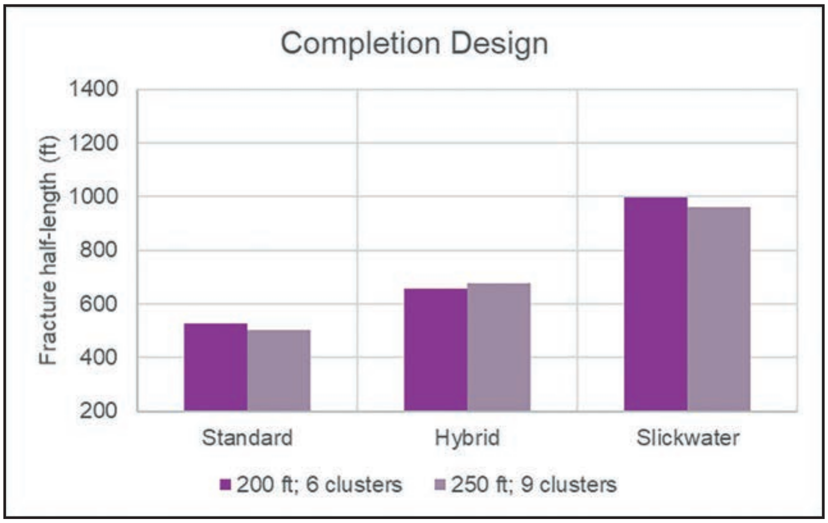


FIGURE 1. By deciding on a 250-ft stage length for these fluid systems, based on the pressure-based fracture map, an Eagle Ford operator achieved the same fracture half-length as the historical 200-ft completion design. *(Source: Reveal Energy Services)*

Figure 2 shows the results. Stages with 25 bbl/ft and 32 bbl/ft showed similar fracture half-lengths. Increasing the volume from 32 bbl/ft to 40 bbl/ft, a 25% increase, had a significant change in the resulting half-length. Half-lengths were 33% longer with the 25% increase in fluid volume.

Using these results, the operator was able to decide on various completion design parameters for field development. The results were derived from the physics-based model of nonintrusive pressure data acquisition and analysis that offered

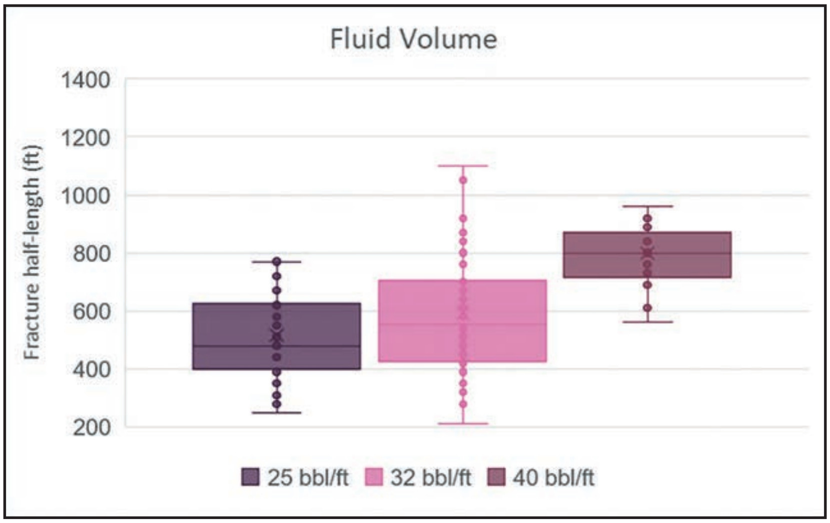


FIGURE 2. An Eagle Ford operator increased fracture half-lengths 33% with a 25% increase in fluid volume. *(Source: Reveal Energy Services)*

more reliable, confidence-building measurements compared with the conventional methods.

As additional confirmation of the validity of this physics-based approach with the new fracture map technology, the operator's team compared all of the completion results with the production data. The production data confirmed the conclusions from the pressure-based fracture map analysis.

The pressure-based fracture map offers the industry a new diagnostic means to validate a completion design on every well with minimum operational risk and cost. The simple, accurate, affordable pressure-based fracture map enables operators, as described in this case study, to make informed, better completion decisions. ■

Stage Consolidation Leads to Value-added Cost Efficiencies

Strategic diagnostics help a Delaware Basin operator increase efficiency and returns in its horizontal well completions program.

By Buddy Woodroof and **Claudio Ramos**
ProTechnics, a Division of Core Laboratories

Amidst a slight uptick in activity at recently improved commodity prices, the petroleum industry is still well below 2014 peak levels and overall drilling fewer but more efficient wells. Operators are maintaining a sense of caution when approaching development strategies, seeking opportunities to improve operational efficiencies and maximize ROI quickly.

One approach to improve operational efficiencies involves the consolidation of processes or procedures. ProTechnics partners with operators to identify and evaluate these opportunities through a strategic diagnostics program. This approach emphasizes early learnings in a development cycle, establishing a foundational knowledge then evolving to more intricate fine-tuning of drilling and completion programs.

In the case of an operator moving into new acreage in the Delaware Basin, the challenge was understanding what strategies could migrate into the new area. For example, how does the prior completion strategy translate? What changes should be considered? What can be improved? Together, ProTechnics and the operator were able to align technology, experience and business initiatives to develop a plan for success.

One area for a potential increase in efficiency involves a reduction in the number of stages required to complete a horizontal well, which can have a significant impact on the completion and stimulation program costs. It must not come, however, with a sacrifice in stimulated reservoir volume or a loss of production, and it must come quickly to maximize the financial impact under the current development program.

Any time an operator is considering material changes to completion design, understanding cluster efficiency is key. To make decisions going forward, an operator must first understand the completion. Is the entire wellbore being treated or is all production coming from only half or maybe one-third of the lateral?

In this project, a procedural change reduced total stages by 4% over the 2018 program while maintaining 100% cluster efficiency. By reducing the learning curve to a single well, the operator immediately begins realizing a $5,000,000 positive impact on the bottom line.

Brief reservoir background

The reservoir in question is the Wolfcamp/Bone Springs in Pecos County in the Delaware Basin of West Texas. During basinal Wolfcamp deposition, the southern section of the Delaware Basin was subject to tectonic and hydrographic conditions that were less prevalent in other areas of the Permian Basin. The lithofacies are potentially significant concerning organic carbon production, natural fracturing and geomechanical rock properties relevant to hydraulic fracturing. The wells in this study were landed in the Wolfcamp A zone or the approximately 300-ft shallower Bone Springs. Cores taken in and adjacent to the Wolfcamp A in this area reveal substantial lithofacies variability, grading from a siliceous mudrock upward through silt and sand turbidites and further upward into calcareous and siliceous mudstones.

Fracture design changes

It was estimated that for a 10,000-ft lateral, reducing the number of stages from the typical 51 down to 49 could reduce completion costs and time while maintaining perforation efficiency. To ensure equivalent lateral coverage with fewer stages, it would be necessary to increase the number of perforation clusters in each remaining stage. With a higher perforation count per stage, it was deemed necessary to increase the total fracture rate to obtain sufficient rate per perforation to maintain the established limited-entry design criteria.

The design changes that were employed included an increase in perforation clusters per stage from six clusters to seven to eight clusters while maintaining a minimum fracture rate of 4 bbl/min per perforation or approximately 90 bbl/min total rate. The overall completion criteria were otherwise comparable to those used previously in the area (i.e., cemented plug and perf; slickwater fluids; 100 mesh sand, 40/70 mesh sand, and 40/70 mesh curable resin-coated sand; a maximum proppant concentration of 2 ppg; total proppant placement of approximately 2,500 lb per lateral ft; and rate diversion only).

To quickly determine the efficacy of the design changes in the comparable reservoir rock, testing was implemented on the first Wolfcamp lateral in the completion program. The stage lengths and number of perforation clusters per stage were varied across stages 11 through 47 (stages 1-10 were completed

Stage	Clusters	Stage Contain	NWB Prop (ft)	Traced M Lbs	BPM/Perf
11	6/6	Good	175	415.8	4.0
13	6/6	Poor	177	419.3	4.9
15	6/6	Poor	177	420.1	4.5
17	6/6	Poor	173	419.6	4.9
19	6/6	Poor	179	419.0	4.6
21	6/6	Poor	179	419.0	4.7
23	6/6	Poor	178	419.6	4.9
25	6/6	Poor	178	420.7	4.7
27	7/7	Good	223	525.1	4.3
29	7/7	Fair	217	525.7	4.1
31	7/7	Fair	220	525.3	4.2
33	7/7	Good	219	524.8	4.3
35	7/7	Good	205	525.3	4.3
37	7/7	Good	221	518.6	4.2
39	7/7	Fair	222	524.9	4.3
41	7/7	Good	222	525.1	4.3
43	7/7	Good	224	525.3	4.3
45	7/7	Good	219	524.9	4.3
47	7/7	Poor	221	525.9	4.3
Total	**125/125**		**3,826**	**9,124**	
Avg	**100%**		**201.4**	**480.2**	**4.43**

FIGURE 1. The results from the Wolfcamp lateral completion parameters/completion are presented. *(Source: ProTechnics)*

conventionally but not included in the study). All odd-numbered stages from stages 11 through 25 were approximately 175 ft in length (plug to plug) and were completed with six clusters per stage. All odd-numbered stages from stages 27 through 47 were approximately 225 ft in length (plug to plug) and were completed with seven clusters per stage. Completion diagnostics were not employed in even-numbered stages to evaluate stage containment. Figure 1 summarizes the individual completion parameters and results for the stages included in the study.

Objectives

To ensure that there was no loss of perforation-cluster-treatment efficiencies or overall lateral coverage, SPECTRASTIM proppant tracers were added to the proppant slurry for each targeted stage of the Wolfcamp lateral, and the lateral was logged with a SPECTRASCAN imaging tool. Each perforation cluster was examined on the spectral gamma-ray log to determine cluster treatment efficiencies, the extent of lateral coverage for each stage, cement integrity, stage containment and early versus late proppant placement. A blue antimony tracer was used in 0 ppg to 0.5 ppg 100 mesh proppant ramp, a red iridium tracer was used in 0.5 ppg to1.0 ppg 40/70 mesh proppant ramp, and a yellow scandium tracer was used in 1.0 ppg to 2.0 ppg 40/70 mesh proppant/resin-coated proppant ramp.

To assess the extent of vertical height growth/communication between the proppant-traced Wolfcamp lateral and the parallel 300-ft shallower Bone Springs lateral, a SPECTRASCAN imaging run was also performed on the previously hydraulically fractured but untraced Bone Springs lateral.

The extent of fracture fluid cleanup by the Wolfcamp lateral and fracture fluid communication with the Bone Springs lateral were evaluated using SPECTRACHEM chemical tracers injected throughout each stage of the Wolfcamp completion. Wellhead water samples collected during flowback of the Wolfcamp well were analyzed for each of the injected tracers recovered from the two wells. Wellhead water samples also were collected during production of the Bone Springs well, and they were similarly analyzed for each of the communicated tracers from the Wolfcamp well.

Informed decisions

Figure 1 summarizes the completion parameters for the Wolfcamp lateral for the odd-numbered stages 11 through 47. Stages 11 through 25 were the shorter stages (approximately 175-ft stage lengths) and were perforated with six clusters per stage. Stages 25 through 47 were the longer stages (approximately 225-ft stage lengths) and were perforated with seven clusters per stage.

Figure 2 adds some additional completion parameters detailing the fluid and proppant volumes for each stage and incorporating the SPECTRASCAN log, which reveals the early, intermediate and late traced proppant gamma ray counts for each stage.

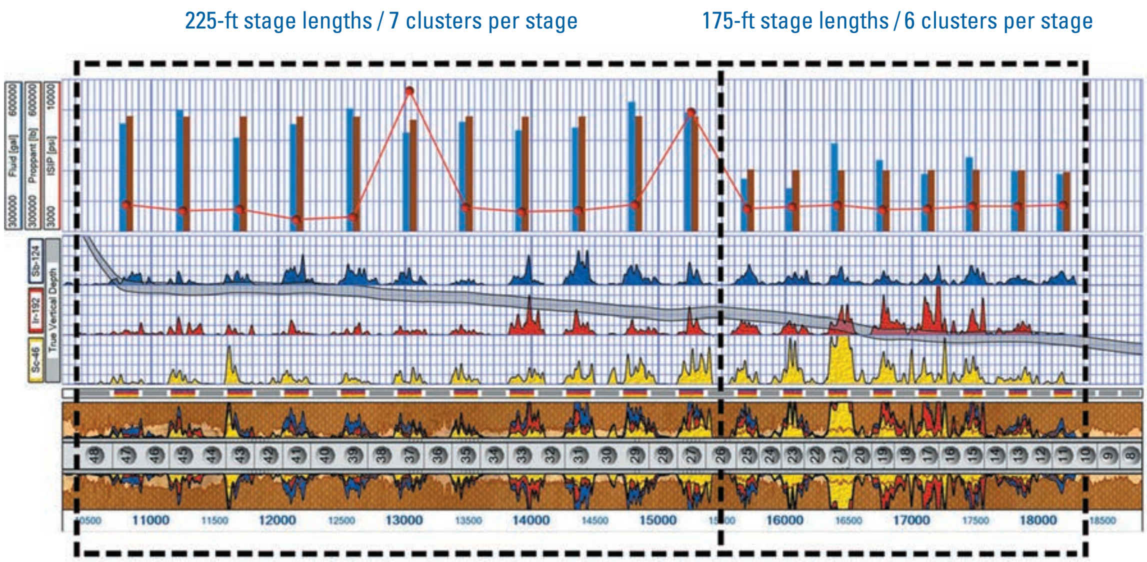
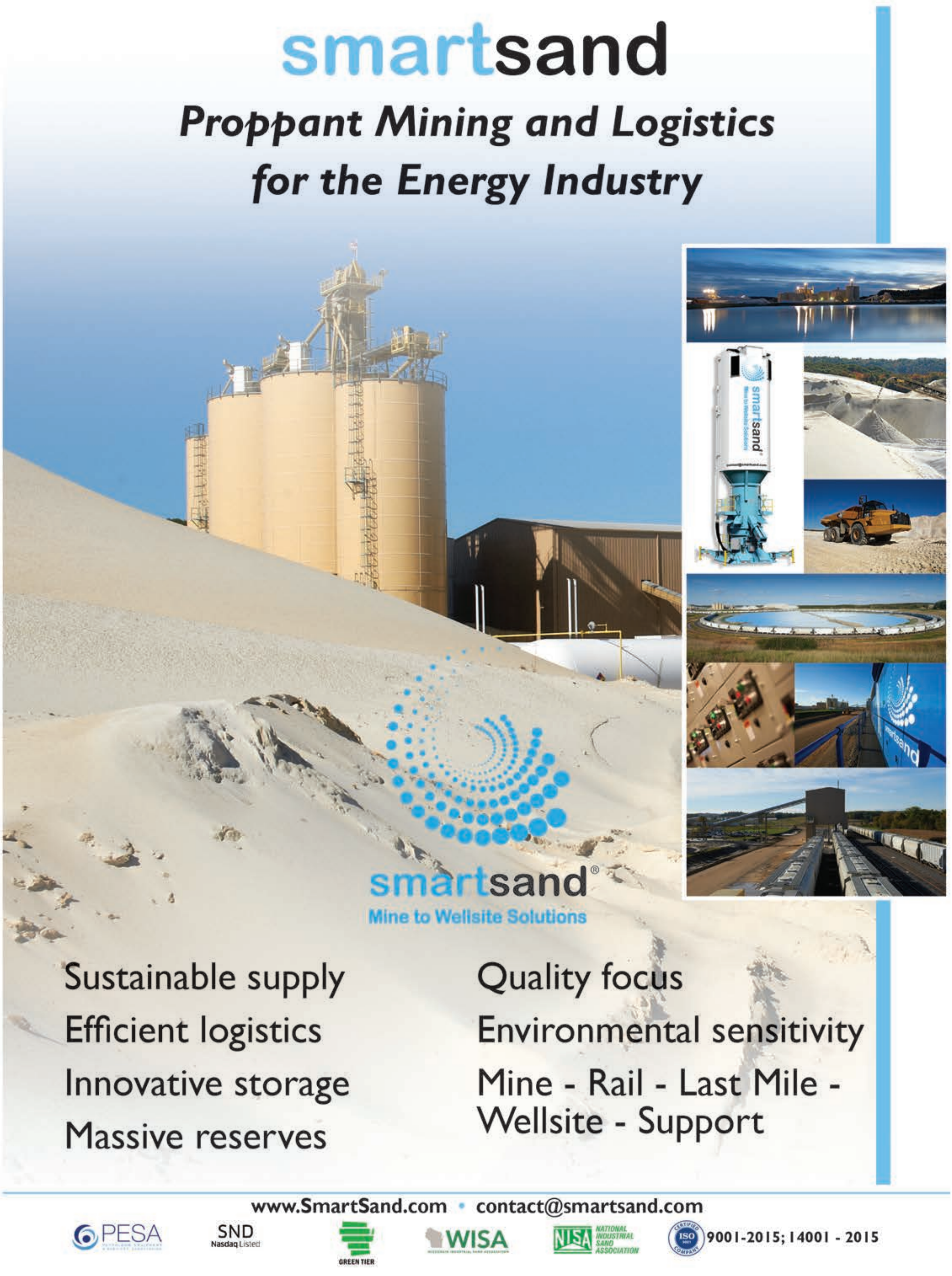


FIGURE 2. The fluid volumes (blue bars), proppant volumes (brown bars) and proppant placement (blue/red/yellow tracks) are displayed for the Wolfcamp lateral. *(Source: ProTechnics)*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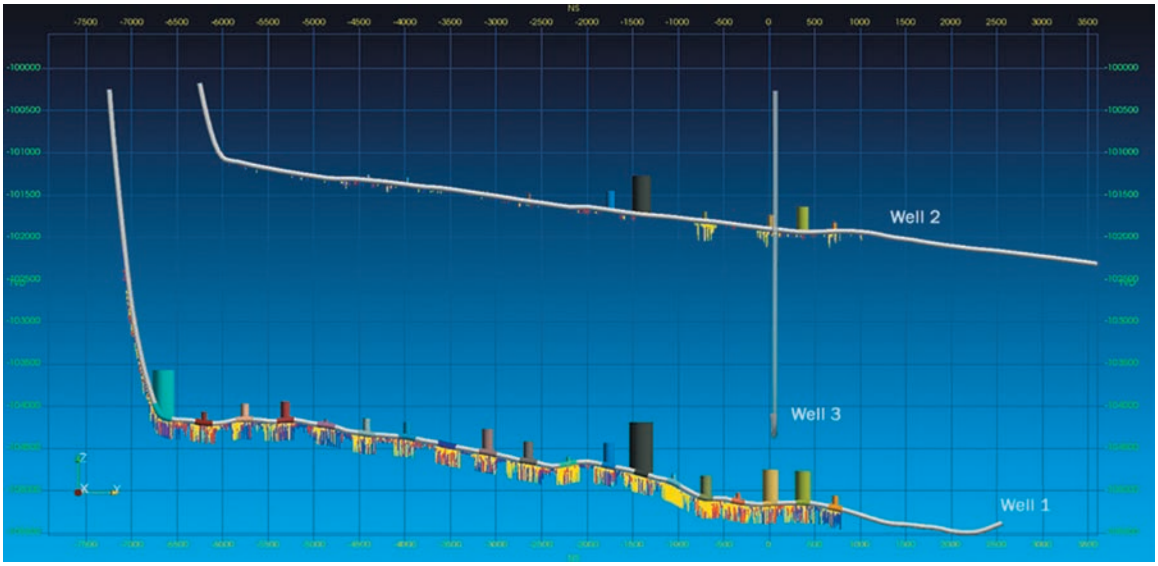

FIGURE 3. The proppant tracer placement/communication below the laterals and fluid tracer recovery/communication above the laterals are shown. *(Source: ProTechnics)*

In general, the shorter stages exhibit higher late scandium-traced proppant counts, while the longer stages exhibit better stage containment. All of the stages reveal excellent cluster treatment efficiencies and near-wellbore proppant coverage. The shorter stages averaged 4.7 bbl/min per perforation, while the longer stages averaged 4.3 bbl/min per perforation. In both cases, there was ample rate to ensure effective limited-entry fracture fluid and proppant distribution.

Figure 3 depicts the traced proppant placement for each stage on the underside of the Wolfcamp lateral (Well 1) and the fracture-fluid-flowback results (chemical tracers) on the upper side of the Wolfcamp lateral. It also depicts the extent of communication between the traced Wolfcamp lateral (Well 1) and the untraced, shallower Bone Springs lateral (Well 2) in the same format as described for the Wolfcamp lateral. It is interesting to note that the greater extent of both the traced proppant communication and the traced fracture fluid communication occurred in the outer-third of the Bone Springs lateral near a legacy well, Well 3. This observation is believed to be a reflection of Well 3 acting as a depletion sink.

Reducing the learning curve impacts economics

The reduction of two stages per well while maintaining completion effectiveness reduced the total stages required by 4%. By reducing the learning curve down to only a single well, informed decisions could be made immediately and that 4% applied across the entire program, thus maximizing fiscal year 2018 savings of more than $5,000,000.

FIGURE 4. Fiscal Year 2018 Savings

51 stage design	$5,180,854
49 stage design cost saving	$116,302
2 stages perf and plug	$16,000
6 hrs/stage for 2 stages	$24,000
Total savings/well	**$156,302**
32 remaining wells for FY 2018	**$5,001,682**

The results of this study offer encouragement that in some of the Wolfcamp/Bone Springs operating areas in the Delaware Basin it may indeed be possible to increase operational efficiencies and reduce completion costs by consolidating stages, with the possible caveat that limited-entry design criteria be met.

Identifying operational efficiencies can be a challenge. By taking a holistic approach in applying core data, diagnostic expertise and operator experience to sound business initiatives, it is a challenge that can be met with great success. ■

Additional Information on Hydraulic Fracturing

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

By Ariana Hurtado
Associate Managing Editor

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