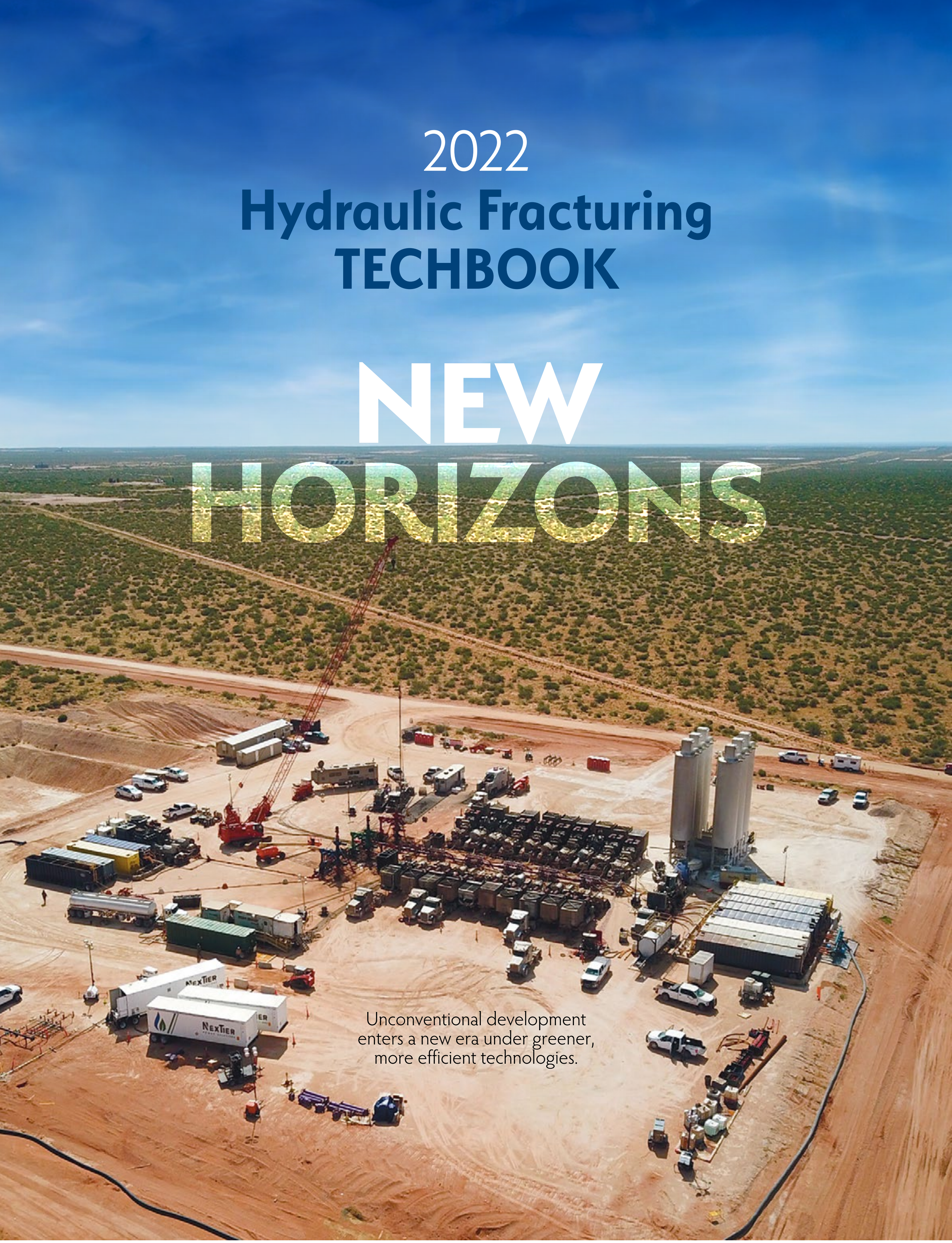


2022

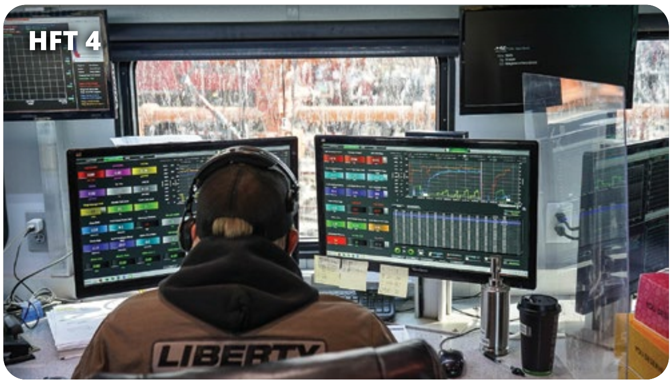
Hydraulic Fracturing TECHBOOK

NEW HORIZONS

Unconventional development enters a new era under greener, more efficient technologies.


UNIVERSAL

Table of Contents



ABOUT THE COVER: With shale producers having struck a balance between shareholder returns and optimized production growth, they now face a new era that prioritizes environmentally friendly operations and securing energy resources for not only the U.S. but for much of the world. New technologies, optimized completion designs and improved knowledge of well designs are helping operators meet these shifting priorities. *(Source: NexTier Oilfield Solutions)*

HORSEPOWER, SAND SUPPLY LIMITS SUGGEST TIGHT FRAC MARKET

Additional horsepower capacity will come online later this year, but it may not be enough to bridge the gap to projected demand.

ARTICLE BY
JENNIFER PALLANICH
SENIOR EDITOR

The hydraulic fracturing market through 2023 is expected to be tight. Horsepower and water demand are both projected to rise next year, and sand will likely continue to be an issue, according to Luke Smith, U.S. onshore analyst at Westwood Global Energy Group.

By third-quarter 2023, Smith expects horsepower demand to exceed 14 MMhp. In first-quarter 2022, the active horsepower was 12 million.

"That essentially indicates the market will be very tight. They will need newbuild additions or to reactivate Tier 2 crews," he said.

But reactivation of Tier 2 crews is unlikely, he said, because the costs associated with doing so can range from $2 million to $8 million per crew, and engines may be six or seven years old.

"That's steep," Smith said.

The other alternative is going with a newbuild, which can be had for $20 million to $25 million, he said. "The horsepower that will meet that demand in 2023 will likely come from newgen frac fleets."

At least seven newgen deployments and two conventional units are expected throughout the rest of 2022, he said.

"A lot of that deployment will ease the tightness in the horsepower market," but it won't likely meet all the demand, he said. "Essentially, the market's going to be tight. The frac crew growth is going to be limited."

Some jobs are simul-fracs, but Smith has observed a decrease in the use of simul-frac operations.

"A lot of that has to do with the amount of sand available. There's definitely a shortage in the Permian," he said. "We've heard from pressure pumpers that they're not running as much simul-frac because it requires twice as much sand."

Sand continues to be an issue and is expected to be problematic into 2023.

In first-quarter 2020, the Mine Safety Health Administration recorded 132 sand mines were either active or at 20% or higher utilization but only 94 sand mines in first-quarter 2022, Smith said.

"A lot of Texas regional mines are still abandoned," he said.

Regional mines may be more than 100 miles away from a well site, while in-basin sand mines may be 30 or 50 miles away, he said, noting some mines are coming online in the Haynesville Shale area. Horizontal wells in the Haynesville tend to use more sand, as lateral lengths tend to be a little longer, while those in the Delaware Basin tend to use less sand because they are slightly shorter.

"There are more intense fracs, especially in the Haynesville. We've seen fracs that have 55 million to 60 million pounds of sand," Smith said. "That's probably about 45 million gallons of water; that's quite a bit—almost a million barrels."

Water demand is also increasing, with the average horizontal well consuming about 17.2 MMgal of water, he said. In fact, water use for fracking operations tends to be higher in the Haynesville, which uses 28 MMgal of water for horizontal wells, he said, while it's 20 MMgal and 19 MMgal for horizontals in the Midland and Delaware basins. The Williston Basin, he said, typically uses 9 MMgal of water per horizontal well. "There's a dwindling amount of available hydraulic horsepower in a market that has a ceiling of sand supply that is restricting and limiting the ability of E&Ps to complete their scheduled completions," Smith said. OGI

"Essentially, the market's going to be tight. The frac crew growth is going to be limited."

—Luke Smith,
Westwood Global Energy Group

SHALE PRODUCERS CONTINUE PURSUIT OF FRACKING ADVANCES

Service companies are working to help operators get the most out of aging fields while cutting costs and emissions.

ARTICLE BY
ANNA KACHKOVA
CONTRIBUTOR

The shale industry has evolved considerably since its early days, and this evolution continues as producers keep pursuing technological advances and efficiency gains. While significant advances involving hydraulic fracturing and downhole completions technologies were previously made during commodity price downturns, the current high-price environment does not appear to have stopped the pursuit of new gains.

Cost efficiency remains a priority, but there are also other drivers of technological advances that have emerged, including decarbonization. The industry is also taking a more sophisticated approach to gathering downhole data and responding to it more quickly.

There is room for improvement, however, and as the industry seeks ways to improve, it can also be expected to increasingly embrace automation and digitalization. Another factor to consider is that shale basins are maturing, and producers are increasingly moving out from their core areas into more challenging acreage. Against this backdrop, improving the efficiency of completions and boosting well productivity becomes even more important.

Fracking trends

There are several areas in which fracking and completions technology has advanced during recent years as producers have sought to maximize production. According to Dan Hill, regents professor and noble chair at Texas A&M University's Harold Vance Department of Petroleum Engineering, major trends in fracking technology have recently included the increased use of proppant and fracture fluid, with 2,000 lb/ft of proppant now the average. Laterals have also become longer, with 10,000-ft wells now common, Hill told Hart Energy. Tighter spacing between perforation clusters and fewer perforations per cluster is another recent trend.

"This is aimed at creating denser networks of fractures and to facilitate limited entry effects to fracture more clusters in each stage," Hill said.

Liberty Oilfield Services' vice president of engineering, Leen Weijers, also highlighted this trend as being among one of the most significant.

"On the downhole side, there are continuous efforts to create larger, denser fracture networks that act as the plumbing system to get oil and gas back to the well and to properly scale that frac system for the given well spacing," Weijers said. "Also, this has to be done at an economic optimum—finding a way to further reduce the cost to bring a barrel of oil to the surface. This (dollars per barrel of oil) reduction is currently addressed with more aggressive limited entry perforating, with associated efficiencies enabling us to treat a longer piece of the lateral at the same time."

There are several ways in which costs of bringing a barrel of oil to the surface can be reduced. Among them is the use of locally sourced sand for proppant, as well as smaller-sized proppant, such as 100 mesh.

"This is primarily to reduce transportation costs, a major cost of hydraulic fracturing operations," Hill said. He noted that this is one of the areas where cost-cutting is tied to decarbonization.

Emission and cost cuts

"Emission reductions for fracturing operations are tied directly to costs, so there is significant incentive to reduce both," Hill said. "A huge source of emissions for fracturing is truck traffic. For example, a typical South Texas frac job requires about 900 truck trips just to transport the proppant to the well site. If water also has to be trucked, that is hundreds more 18-wheeler round trips, so companies are building pipeline systems to transport the frac water to their well sites and using locally sourced sand as proppant to reduce the miles of truck transport required."

Another significant trend that ties cost-cutting and decarbonization efforts is the ongoing shift from diesel to electric and natural gas-fueled frac fleets.

"Lower emissions are certainly a driver. Our customers and even some of our vendors are keen on understanding how our equipment will help them meet

LIBERTY RESOURCES

Liberty is constantly striving for further efficiency gains and aiming to step up how much it can pump.

their emission commitments," Weijers said. "Reduction in fuel cost goes hand in hand with this goal."

Liberty is tapping into this trend with its digiFrac offering, whose rollout will be driven by customers that want to achieve fuel savings by switching from diesel to natural gas, Weijers said.

"We are putting significant effort into our digiFrac system, which will run on 100% natural gas, and, depending on the source of the natural gas burned in modern frac engines, the price can be 20% to 40% of the cost of diesel," Weijers said. "This is a significant source of savings on dual-fuel and gas reciprocating engines, and these savings alone can go a long way to justifying the upgrade to the next generation of equipment."

The company is now testing a new offering, digiFrac Prime, which is aimed at providing even further fuel savings by "mostly skipping a few steps in the power transfer."

Other oilfield service providers are also embracing the shift away from diesel in fracking operations.

"As today's fracture operations become more complex, the industry is realizing the benefits of an electric powertrain," Halliburton's vice president of production enhancement, Shawn Stasiuk, said. "Electric fracturing is another important advancement. In addition to lowering emissions and fuel costs, the performance of these electric systems supersedes conventional engines. These machines deliver higher and more consistent horsepower, they are more reliable, and simpler to maintain and operate. Today's electric fracturing technology delivers on reduced emissions and fuel cost savings, without having to sacrifice on the performance required to deliver today's high-intensity fracture operations."

Stasiuk sought to emphasize the importance of cost when it comes to electric fracking.

"ESG is a key driver in every conversation, but so is cost, both for us and our customers," he said. "The commercial construct of an electric offering needs to make sense first, and then we can leverage the lower emission benefit. We adopted an electric hybrid model that allows flexibility and customization, so more operators can begin to adopt this technology at a pace that works for them."

Future of fracking

Halliburton Co. views low-emission fleets as one of the major drivers of fracking technology and looking ahead into the future. It considers intelligent fracturing, entailing automation and the use of real-time data, to be another major driver.

LIBERTY RESOURCES

Halliburton's SmartFleet intelligent fracturing system was developed as the industry increasingly relies on real-time data to improve performance.

HALLIBURTON CO.

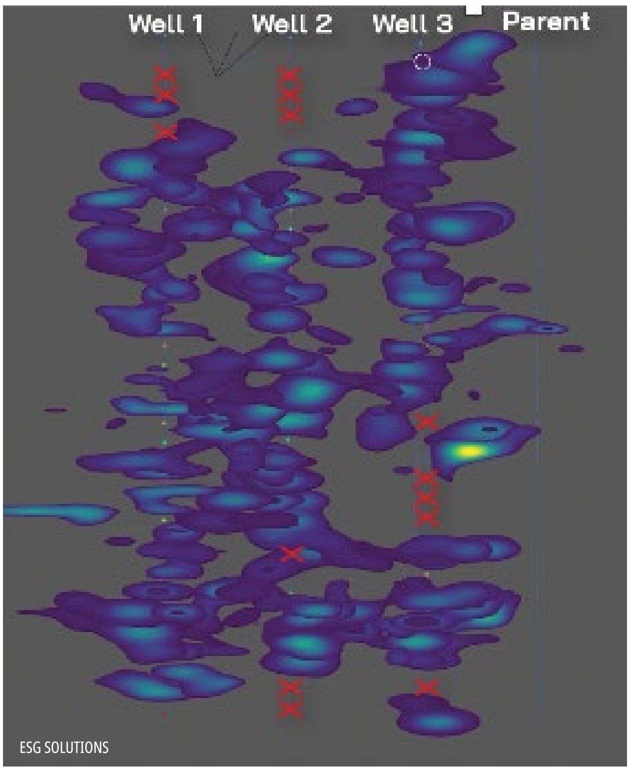
An all-electric frac site sees customers increasingly realizing the benefits of electric power trains as fracture operations become more complex.

"For intelligent fracturing, the evolution of adoption accelerates as we integrate digital and automation into a solution that an operator can scale," Stasiuk said. "We provide solutions that deliver the digitization and automation of surface operations combined with the optimization of subsurface outcomes."

Halliburton has developed its SmartFleet intelligent fracturing system and believes that as the industry increasingly embraces data and automation, this type of real-time system represents the future of fracking.

"SmartFleet is the culmination of many years of listening to the toughest challenges our customers face in hydraulic fracturing," Stasiuk said. "In particular, they pump millions of dollars of sand and fluid downhole and don't fully understand the effectiveness of that investment. First, we want to understand what's going on downhole, then we need a solution to act on real-time data to create more effective, consistent fracs. Just like the onset of MWD in drilling created the need for rotary steerable, the use of fiber optics for frac operations created a need for a tool to control the outcome of what we see downhole. SmartFleet is that tool."

The importance of using real-time data was also highlighted by ESG Solutions, which was acquired by subsurface imaging and frac diagnostics company Deep Imaging in 2021. The transaction gave the companies an expanded suite of real-time analytical tools, according to ESG's CEO David Moore.



ESG SOLUTIONS

ESG Solutions monitors a three-well zipper using Deep Imaging Electromagnetic technology.

"We've got a breadth of technologies that we can combine to provide real-time data so that they can make better completions decisions, and those completions decisions should drive value in production," Moore said. "I think historically, if we look at any of the technologies, whether it's downhole, borehole microseismic, our electromagnetic [EM] technology, or if they're using something like tracers—any of the technologies—they have to understand the efficacy of their completions are always still a look back, or a lot of them are. They're starting to use pump data to make on-the-fly decisions stage by stage. We're providing stage-by-stage, real-time borehole microseismic so that they understand what the fracture networks are doing on a stage-by-stage basis."

Room for improvement

The use of real-time data could be better still, however, and Moore sees room for improvement.

"The thing that I still struggle with is that because of investment dollars, a lot of the production data isn't shared right away," he said. "And it's hard for the customer to correlate the production they're getting from a completion that happened a year ago when they're already on to the next formula, the next model. We as an industry need to probably adopt things a little bit faster, so that we can pull it all together and make the right changes."

Conversations are increasingly happening about operators moving away from following fixed models and completions recipes, Moore noted. And this will become even more important as they move away from what he describes as A acreage to B acreage.

"A lot of our customers entering B acreage really need to understand what's going on and find the most effective plan, in real time, so that they can produce at the levels that they're promising their investors," he said.

More advanced diagnostics could also be helpful in other areas where there is room for improvement, according to Texas A&M's Hill.

Liberty's customers and vendors are keen to understand how its equipment will help them meet their emission commitments.

LIBERTY RESOURCES

"There is still a lot of uncertainty about the distribution of proppant in the created fracture systems, so more advanced diagnostic methods that can locate proppant far from wells would be of great benefit," he said.

Beyond this, operators and service providers alike can be expected to continue their pursuit of efficiency gains and of doing more with less. This trend may have been accelerated by the oil price downturns of the past decade, but it has not gone away in the era of higher oil prices, as producers remain under pressure to prioritize shareholder returns and as rising costs squeeze margins for operators and service providers alike. Liberty's goals serve as an illustration of this pursuit of continuous improvement.

"We are constantly striving for further efficiency gains and to safely pump a larger portion each day," said Liberty's Weijers. "Proof of that is the constant increase in sand throughput as measured per Liberty employee. Over the last decade, this metric has gone from about 800,000 pounds per employee per year to 8 million pounds per employee per year. This is the result of numerous small improvements in technology and efficiency. We do not see a break in the trend of this key metric."

Within that, there are several ways in which the company is pursuing additional efficiency gains.

"Two of the many initiatives we are working on focus on running pumps within a more restricted domain of interlocks, helping in a reduction of downtime and repair and maintenance cost; testing 'hot swaps,' where we can pull out and depressurize a horsepower unit while pumping the main job with remaining pumps, thus enabling our crew to conduct maintenance on this pump outside the red zone," Weijers said.

Market challenges

The industry is now having to contend with new challenges in the form of rising costs and supply chain constraints. Thus far, higher oil prices have helped operators to ramp up drilling and completion activity—albeit cautiously—but they run the risk of being constrained by supply chain issues.

"Drilling and completion activity always follows oil and gas price trends, and that is happening again," said Texas A&M's Hill. "I expect drilling and fracturing activity will continue to increase until limited by the availability of drilling rigs or frac fleets."

Constraints are starting to materialise in several areas, as evidenced by oilfield service providers' recent experience.

"The market remains tight for hydraulic fracturing, and we remain sold out through the second half of the year," said Halliburton's Stasiuk. "Lead times on parts, pumps and people are constraining the number of spreads we can add to meet this demand, and we expect next year to remain extremely tight for fracturing services. However, through our experienced people and an expanded supply chain, we are prepared for the increased activity and will continue to execute at the level the industry expects."

Liberty has also run into some constraints.

"There have certainly been challenges in keeping up with rapid changes in prices for commodities such as sand and diesel, and associated with sourcing basic parts, such as air filters," Weijers said. "The supply chain constraints of 2022 have also caused our digiFrac rollout, particularly the power component, to be rolled out somewhat later that we had initially intended."

ESG's Moore said his company has had to focus on becoming more efficient.

"We've had to figure out how to get the same fidelity in our technology, whether it's our EM, our borehole microseismic [or] our fiber," he said. "How do we get more efficient in deploying? Can we get the same fidelity with a smaller array?"

And while this has been challenging, the company has succeeded in making these efficiency gains, he added.

"Market challenges a lot of times equal innovation," Moore said. "And we've done a lot of that through this, we're not the only ones. And our customers have as well. They're trying to figure out better ways to use the data. I think a lot of what the price is and the cost and everything going on in the world—not just in our industry—has really started to drive innovation internally for us as well for our customers."

This goes against the belief that most innovation happens during oil price downturns for the industry. Regardless of crude price levels—currently above $100/bbl—the pressure to innovate and pursue efficiencies does not look likely to ease anytime soon. Operators and service providers will likely keep experimenting with various technologies and methods, but momentum is picking up for some, such as the use of real-time data, more than others. This can be expected to drive the emergence of more dynamic completions models, and, with the industry increasingly having to target more challenging acreage, this is timely.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MARKET ANALYSIS

HOW FAR HAS US HYDRAULIC FRACTURING COME?

Pumpers continue to push the pace, paving the way for greener solutions.

ARTICLE BY
JUSTIN MAYORGA
RYSTAD ENERGY

The U.S. hydraulic fracturing sector has undergone significant change in the past year as companies alter their initiatives and business strategies in response to market tightness, rising costs and a push for cleaner oilfield solutions.

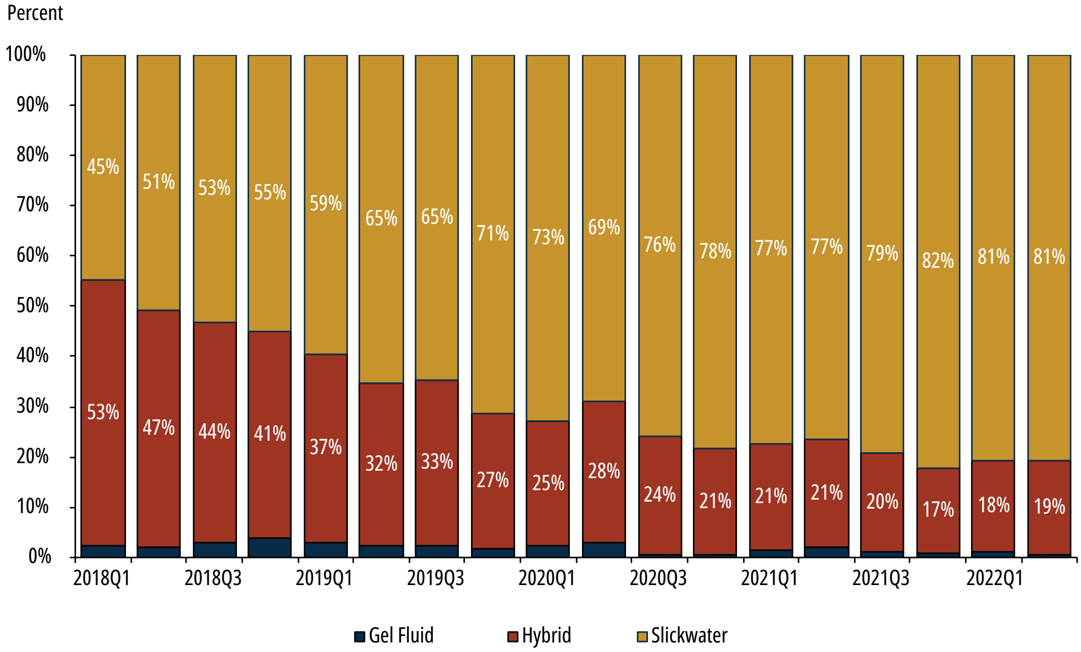
In the U.S. onshore region, operators are seeking innovative ways for improving customer value by boosting efficiencies or shifting away from diesel to reduce well costs. An uptick in demand for natural gas-capable fleets in 2022 has been a leading innovation, reshaping the landscape of frac fleets traditionally made up of Tier 2 diesel equipment.

Alongside this, advancements in completion techniques, such as simul-fracturing or dual frac, continue to push completion efficiencies to new levels, achieving superior rates over traditional zipper fracturing operations. Leveraging Rystad Energy's well level database and research, we have explored the U.S. hydraulic fracturing landscape to identify and compare historical techniques to current trends.

What's next for fluid systems and proppant intensities?

In terms of the material composition of frac jobs, hydraulic fracturing methods have remained systematically the same for years. The process involves injecting high-pressure proppant-laden fluid into a reservoir to increase surface area for hydrocarbon extraction. Fluid systems have trended in one direction in recent years with a strong shift between crosslink and hybrid fluid systems to pure slickwater. Ultimately, over 80% of well completions now use pure slickwater fluid systems (Figure 1).

Figure 1: US Land Fluid Systems



Source: Rystad Energy ShaleWellCube, Rystad Energy research and analysis

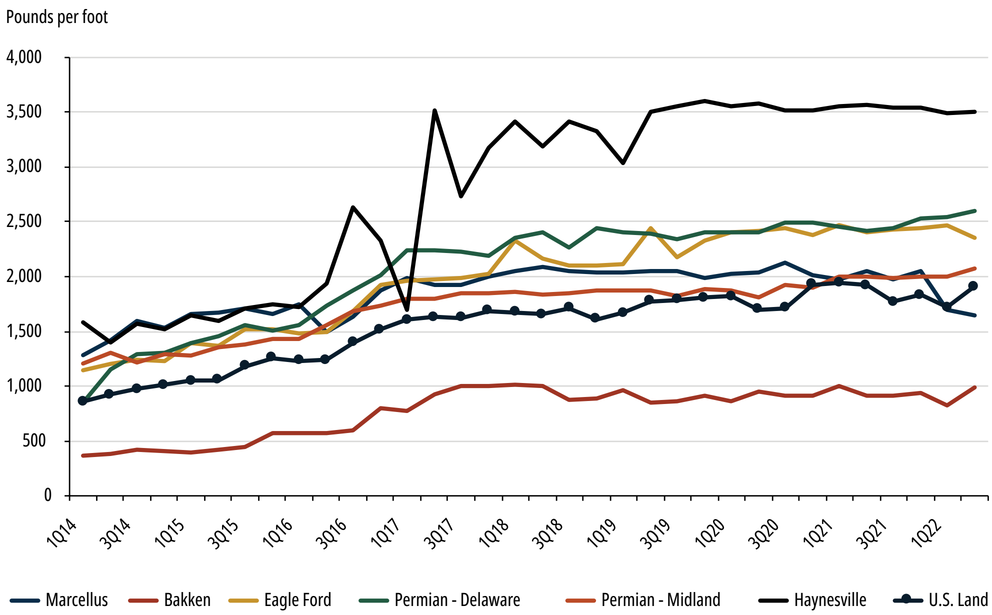
More than 80% of well completions now use pure slickwater fluid systems.

Rystad Energy analysis shows that the use of hybrid fluid systems (slickwater systems with a tail end of gel or crosslink during higher proppant concentrations) has fallen by 6% in 2022 compared with 2020. With treatment rates in some cases well above 100 barrels per minute (bbl/m), the need for crosslink fluid systems for proppant transport is typically not required. Ultimately, it comes back to cost savings as a friction reducer is traditionally a lower-cost chemical additive compared to crosslink and guar gel.

So far in 2022, approximately 90% of completions in the Permian Basin, Bakken Shale and Appalachia have used slickwater fluid designs. Other basins, such as the Haynesville, Denver-Julesburg (D-J) and Midcontinent also heavily use pure slickwater designs but have also increased their use of hybrid designs.

Proppant selection has also shifted predominantly to 100 mesh and, on a basin level, proppant intensities per well have stabilized (Figure 2). Since 2018, levels have only slightly increased compared to 2022 levels. However, the means of acquiring proppant continues to evolve. This year has been one typified by inflation and rising costs, particularly for diesel, which has led to an increase in last-mile trucking for proppant deliveries to frac locations. Because of this, mobile mini-mines have started to become popular within basins such as the Permian.

Figure 2: US Land Proppant Intensities

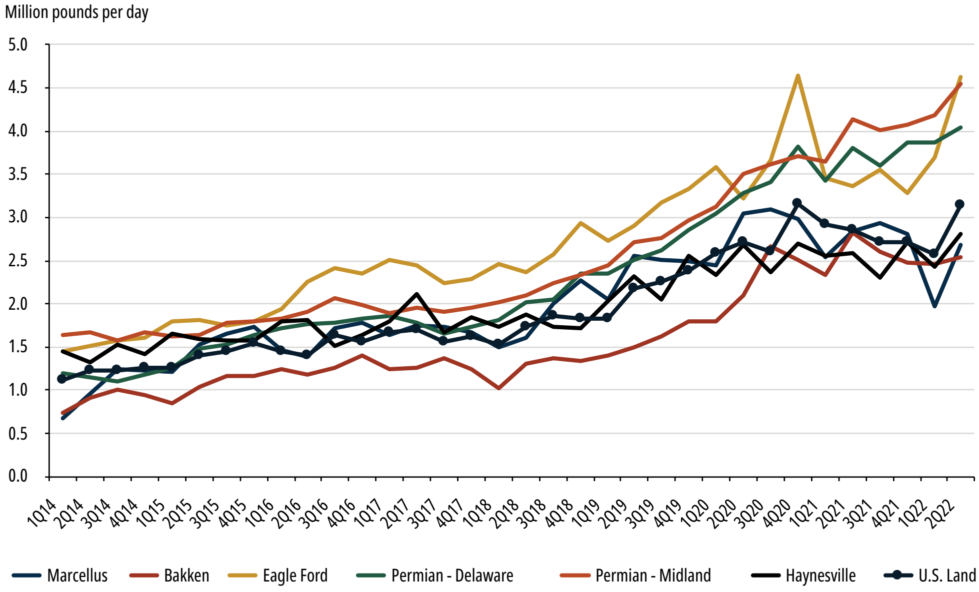


Source: Rystad Energy ShaleWellCube, Rystad Energy research and analysis

Proppant selection has shifted predominantly to 100 mesh and, on a basin level, proppant intensities per well have stabilized. Since 2018, levels have only slightly increased compared to 2022 levels.

By basin, the amount of proppant pumped per day has continued to increase since 2018.

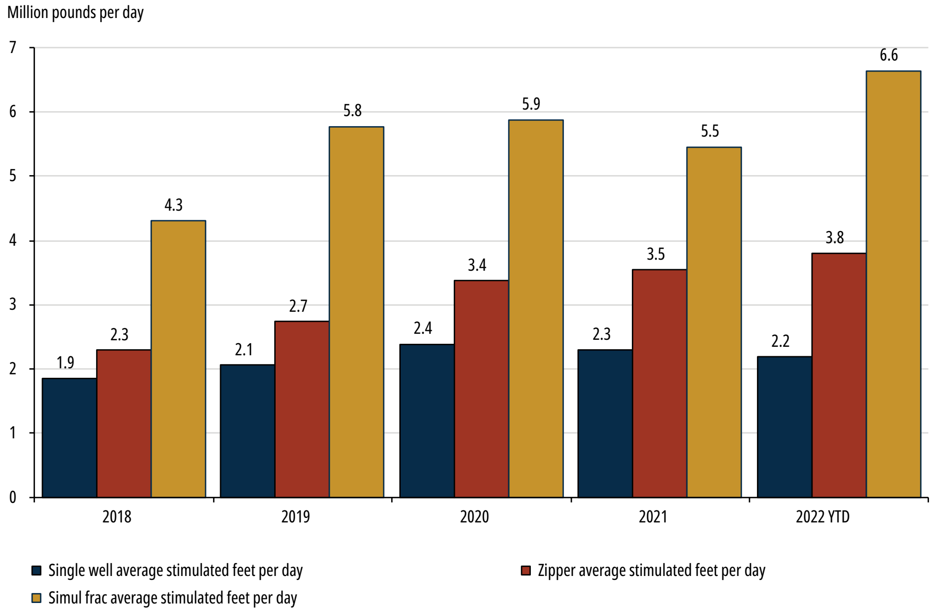
Figure 3: US Land Proppant Pumped Per Day



Source: Rystad Energy ShaleWellCube, Rystad Energy research and analysis

This chart compares single-well, zipper frac and simul-frac operations to give an insight on the superior speeds that simul-fracs allow.

Figure 4: US Land Proppant Per Day By Frac Type



Source: Rystad Energy ShaleWellCube, Rystad Energy research and analysis

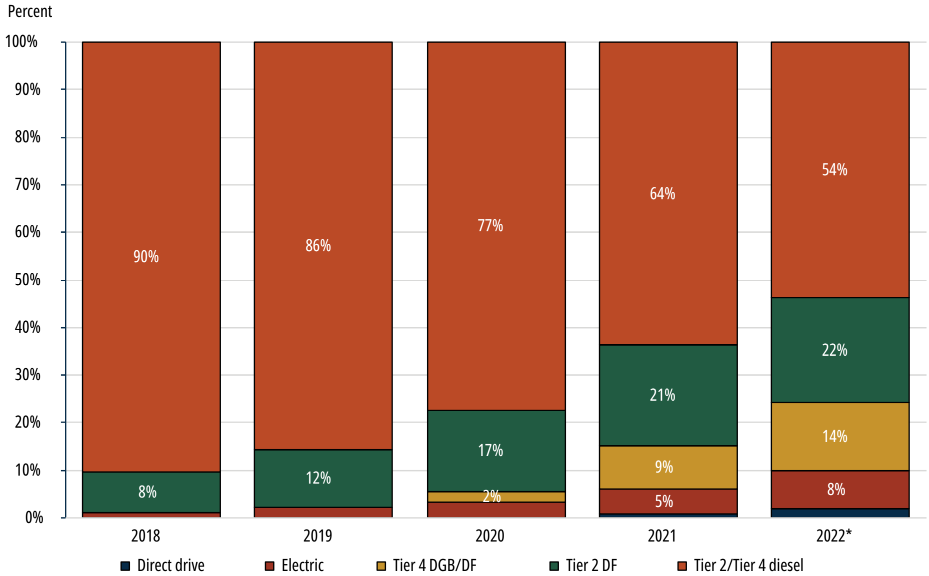
These mobile mines are estimated to have nameplate capacity of approximately 750,000 short tonnes compared to a traditional in-basin sand mine, which typically has nameplate capacities of 3 million to 4 million short tonnes. What makes these mobile mini-mines interesting is their wet sand application over traditionally dried processes. Wet sand currently has not shown any immediate impact on the overall performance of hydraulic fracturing operations and again, it comes back to cost. Using wet sand removes the drying process, which reduces the overall cost of proppant material.

New stimulation methods

While fluid and proppant selections have slowly shifted, completion speeds continue to steadily increase, with an average 8% increase in proppant pumped per day for U.S. land in 2022 compared to 2021. Figure 3 breaks down by basin the amount of proppant pumped per day, which has continued to increase since 2018. The largest gains are in the Permian where proppant pumped per day has increased 11% so far in 2022 compared to 2021 and by 24% compared to 2020. This is partly due to the increased use of simul-frac or dual frac within the Permian Basin compared with others.

So far in 2022, Rystad Energy estimates that 84% of all simul-frac operations are in the Permian, with a smaller percentage in the Eagle Ford Shale and D-J Basin. Simul-

Figure 5: US Land Equipment Landscape At Year's End



*Forecast

Source: Rystad Energy research and analysis

Rystad Energy estimates that dual fuel or dynamic gas blending currently make up 30% of total inventory, representing a 12% growth since 2020. By end-2022, this is expected to grow to 36%.

fracturing involves using a single frac spread to stimulate two wells while dual frac is essentially a simul-fracturing operation but with two frac spreads. In 2022, pproximately 9% of all horizontal wells were completed with either technique, the largest adoption rate to date. Essentially by completing two wells at once, operators can decrease cycle times and realize first oil at a quicker rate. Figure 4 compares single-well, zipper frac and simul-frac operations to give an insight on the superior speeds that simul-fracs allow. Despite simul-fracturing not currently having a significant influence on other basins, completion speeds continue to increase as crews and equipment become more efficient.

Next generation fleets impact

As ESG initiatives rise up the corporate agenda, the equipment landscape has begun to evolve amid the race to a cleaner oil field solution in hydraulic fracturing. Cutting carbon emissions by displacing diesel as a primary fuel source continues to be used by many E&Ps. Pressure pumpers have responded in recent years by transitioning legacy diesel pumps to upgraded dual fuel (DF), dynamic gas blending (DGB) or electric solutions. DF or DGB pumps both use natural gas to offer partial diesel displacements of between 50% and 85%.

This transition to natural gas-capable fleets continues to be prioritized as diesel prices top $5 to $7 a gallon, pushing out well costs by $500,000 in some cases. Rystad Energy estimates that DF or DGB currently make up 30% of total inventory, representing a 12% growth since 2020. By end-2022, this is expected to grow to 36% as shown in Figure 5. These fleet types continue to be in high demand and remain sold out for the year to date. The bulk of these fleets reside in the Permian, Appalachia and Eagle Ford, but as more operators focus on cost-saving measures, this trend is expected to continue to grow.

Like DF and DGB, demand for electric frac (e-frac) is also soaring due in part to their 100% substitution rate. While e-frac has existed since 2016, the push toward a greener oilfield solution did not properly start until 2020, which caused a domino effect leading to nearly every major pressure pumper having or building an electric offering. These fleets typically leverage a large 35 megawatts turbine or multiple natural gas-reciprocal engines as a power source, allowing the operator to save by completely switching off diesel.

Despite the high demand, Rystad Energy estimates that e-frac currently holds a 5% share of the total fleet inventory, with the expectation that it will rise to 8% by end-2022. Both e-frac and DF/DGB fleets can use field gas, which provides additional benefits for E&Ps. With the use of gas processing skid systems, operators can transfer well gas directly to fuel their operations, cutting fuel costs by an estimated 70% to 80%.

The driver for these changes is a focus on cutting the costs of services and wells. This has been the name of the game in recent years as many E&Ps look to boost cash flows without increasing in scale.

While the industry has been traditionally slow to change, this year and last have shown how dynamically and rapidly the hydraulic fracturing sector can respond to client initiatives by transforming completion speeds using new techniques, a trend which will ultimately change the landscape of hydraulic fracturing equipment. OGI

NATURAL GAS

GLOBAL TENSIONS, MARKET DISRUPTIONS LIKELY MAINTAIN HIGH NATURAL GAS PRICES

Takeaway constraints limit growth opportunities.

ARTICLE BY
DEON DAUGHERTY
EDITOR-IN-CHIEF

Geopolitical mechanizations, domestic supply disruptions and the energy transition are coalescing into a tight market that stands to maintain high commodity prices.

Between July 2021 and June 2022, the average monthly spot natural gas price at the Henry Hub benchmark more than doubled, rising by $3.86/MMBtu from $3.84/MMBtu in July 2021 to $7.7/MMBtu in June 2022, according to the U.S. Energy Information Administration (EIA).

Low inventories have remained below average levels as demand growth generally has outpaced domestic production growth. Indeed, the average inflation-adjusted monthly Henry Hub spot price reached a 12-month high of $8.17/MMBtu in May 2022—the highest price since November 2008, the EIA reported in July.

A cursory look at mid-2022 inventory doesn't explain the high spot and prompt-month pricing, said Barclays analyst Amarpreet Singh. Rather, it is the underlying supply-demand dynamics driving the unusual price points.

For example, the EIA's working storage total of 1.9 Tcf is almost 16% below the five-year average of 2.2 Tcf but still above the 2018 average. All told, the cumulative change in working inventory is trailing the previous 10-year average by 240 Bcf year-to-date.

"Two key trends to highlight are a) a slowdown in domestic supply growth due to capital discipline and plateauing unit productivity in key tight oil and gas regions and higher net exports due to the ramp up in LNG shipments; and b) significantly reduced elasticity of demand from the power generation sector due to capacity reductions and tight coal markets," Singh said.

The EIA forecasts production this year will gain 2.6 Bcf/d from 2021. However, this still implies that net supply at year-end would be below the 2019 level, and that tightness would remain in the market.

Takeaway constraints

Singh said it is likely that takeaway capacity constraints in the Permian Basin could bottleneck supply additions this fall; brownfield capacity additions for three of the existing pipelines in the region—Permian Highway, Gulf Coast Express and Whistler—are in the works but will not come online until the end of 2023.

Meanwhile, production growth in the largest producing region, Appalachia, is constrained by limited pipeline capacity out of the Marcellus Shale. Analysts say that market tightness is unlikely to quickly abate, keeping prices higher long term.

Credit Suisse is projecting that the gas market will likely remain tight through at least 2025.

"A major contributor to the current disruption and tightness of global gas markets is Europe's surging demand for liquified natural gas in order to replace Russian pipeline gas," the investment bank said.

All of which will "support prices amid slower supply growth over the coming months, in our view," Barclays' Singh said.

But meanwhile, U.S. extraction innovation continues to raise domestic natural gas production to new heights.

Since 2001, supply has grown 80%. Between 2005—when production snagged at 18,927,095 Mcf—and the 2021 figure of 37,011,455 Mcf, growth reflects a staggering 96%.

The EIA is targeting U.S. production of dry natural gas to increase again this year—but not as much as demand. The agency in June estimated natural gas production in 2022 to average 96.5 Bcf/d, a 3% increase from 2021.

IEA forecast

Despite its previous rhetoric detailing the countries mired in energy poverty that desperately need natural gas as a bridge fuel to a greener economy, the Paris-based International Energy Agency (IEA) is a consistent contrarian that routinely drags down demand figures.

The agency said in 2020, global demand shrank 1.2% and fell to 3,970 Bcm—below the floor estimated in 2019 at 4 Tcm.

And while IEA had previously forecasted demand growth, the agency in July did an abrupt about face with its "Gas Market Report." This summer, its crystal ball showed a total rise of 140 Bcm in global gas demand between 2021 and 2025—less than half its earlier estimate and a reduction from the 170 Bcm increase last year.

This contraction is a result of Russia's war in Ukraine, supply disruptions and the incumbent high prices as the leading the downward revision, according to the IEA.

"The turmoil is damaging natural gas' reputation as a reliable and affordable energy source, casting doubts about the role it was expected to play in helping developing economies meet rising energy demand and transition away from more carbon-intensive fuels," the agency said in a statement.

The IEA's assessment is not a common one.

Indeed, the agency's position is simply wrong, said energy business advisor Dallas Salazar, CEO of Atlas Consulting Ventures.

"That prognostication is just a joke," he told Hart Energy. "I don't have any rational explanation for why they continue to beat that drum."

Takeaway infrastructure is lacking in some of the U.S.'s gassier plays like the Marcellus and the Utica, but the Haynesville has ample capacity for growth, Salazar said.

"The only cap on natural gas demand is the supply," he said. "And that supply is currently capped mostly by the U.S. and how quickly can we build export facilities, which are incredibly complex and expensive infrastructure developments."

But demand is only heightened by the world's current events. And many parts of the world are building import facilities to transition to natural gas from coal, so the market's tightness will concentrate, Salazar said.

"There is something to be said about the old Aubrey McClendon phrase [advising] to build the supply economy before you build the demand economy," Salazar said. "This is the vision of McClendon coming through natural gas. It is the bridge fuel." OGI

Selected US Average Natural Gas Prices, 2017-2022 ($/Mcf)

	NGPL Composite Spot Price/ Mont Belvieu	Henry Hub Spot Price	Citygate Price	Electric Power Price
2017 Annual Average	$6.92	$2.99	$4.16	$3.51
2018 Annual Average	8.20	3.15	4.23	3.68
2019 Annual Average	5.49	2.56	3.81	2.99
2020 Annual Average	4.47	2.03	3.43	2.48
2021 Annual Average	9.02	3.89	6.11	5.16
2022 4-Month YTD*	$11.72	$5.14	$5.66	$6.05
2021 4-Month YTD	7.34	3.29	6.48	6.52
2020 4-Month YTD	3.79	1.86	3.17	2.43

** Only data through the end of April 2022 is currently available.*

Source: U.S. Energy Information Administration

US Natural Gas Supply And Consumption, 2017-2022 (Bcf)

	Marketed Production	Consumption
2017 Total	29,238	27,140
2018 Total	33,009	30,139
2019 Total	36,447	31,132
2020 Total	40,614	30,472
2021 Total	41,483	30,283
2022 4-Month YTD*	13,949	11,745
2021 4-Month YTD	13,321	11,188
2020 4-Month YTD	13,917	11,289

** Only data through the end of April 2022 is currently available.*

Source: U.S. Energy Information Administration

Annual US Natural Production By Select Regions, 2017-2021 (Volume in MMcf)

	2017	2018	2019	2020	2021
Colorado	1,706,364	1,847,402	1,986,916	1,990,462	1,876,335
Gulf of Mexico	1,060,452	974,863	1,015,343	789,262	769,870
Louisiana	2,139,830	2,832,404	3,212,318	3,206,163	3,383,977
New Mexico	1,299,732	1,493,082	1,769,086	1,948,168	2,327,871
North Dakota	593,998	706,552	850,826	882,443	945,452
Ohio	1,791,359	2,403,382	2,651,631	2,378,902	2,266,636
Oklahoma	2,513,897	2,875,787	3,036,052	2,786,366	2,571,834
Pennsylvania	5,453,638	6,264,832	6,896,792	7,148,295	7,692,658
Texas	7,223,841	8,041,010	9,378,489	9,336,110	9,416,660
West Virginia	1,514,278	1,771,698	2,155,214	2,592,319	2,760,429
Wyoming	1,590,059	1,637,517	1,488,854	1,306,368	1,237,709
U.S. Total	**29,237,825**	**33,008,867**	**36,446,918**	**36,202,446**	**37,011,455**

Source: U.S. Energy Information Administration

MIA STENDAL/SHUTTERSTOCK.COM

FRAC EFFICACY

SHEDDING LIGHT INTO THE WELL

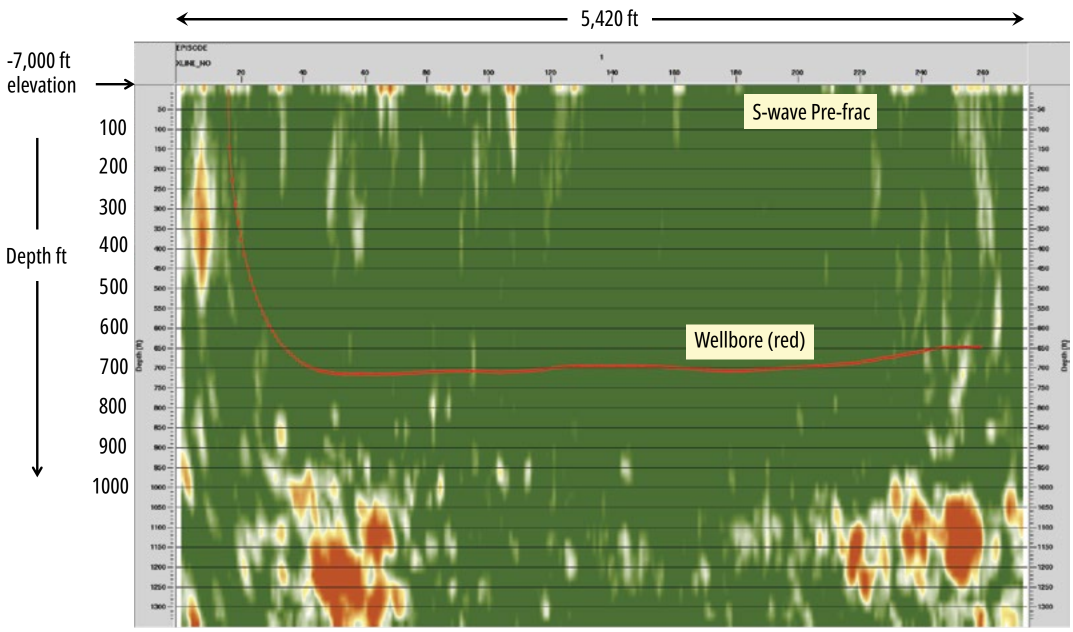
Intelligent fracturing integrates newly affordable tech that gives operators subsurface visibility and control.

ARTICLE BY
JENNIFER PALLANICH
SENIOR EDITOR

There's a lot riding on getting a hydraulic fracture right, but gauging frac efficacy in horizontal wellbores is becoming easier.

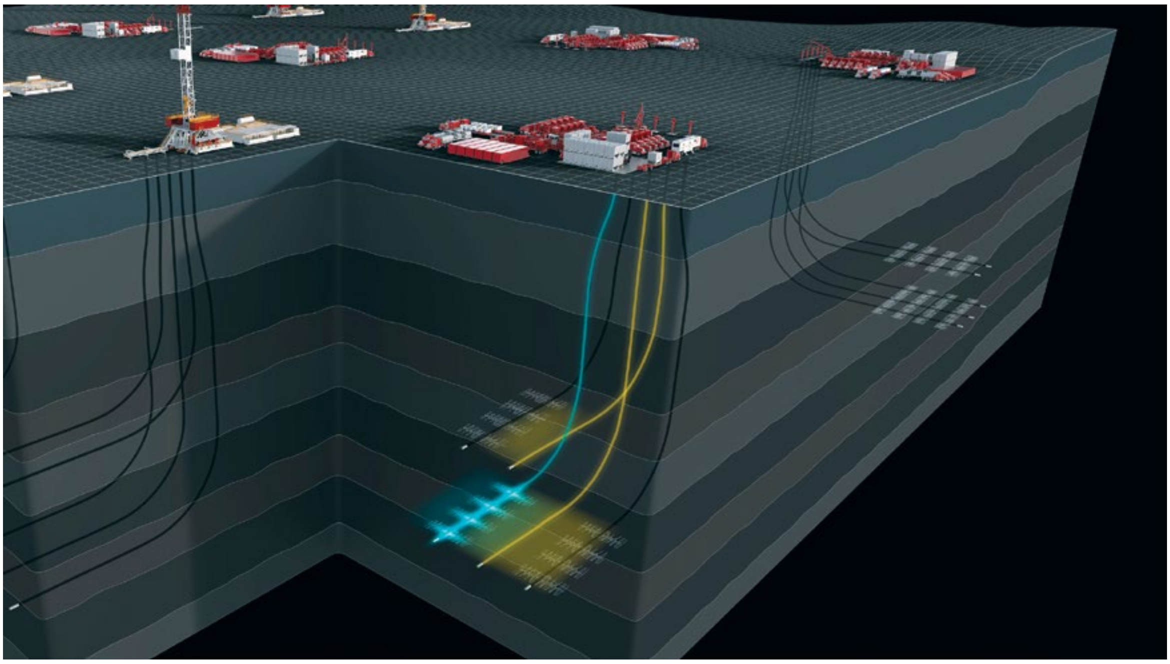
In the early years of the shale revolution, operators had little visibility in what was going on in their unconventional wellbores. They had to rely on inexact, time-intensive or costly approaches to see how their fracs were performing.

But over the years, technologies have improved while decreasing in cost. As a result, technologies such as fiber optics can better inform operators on how fracs in horizontal wells are performing, and new software can help inform an operator about the distance and direction the fractures traveled. Fracturing a



Source: Sterling Seismic

This image shows pre-fracture S-wave diffraction. A baseline time lapse seismic survey was conducted using 91 surface seismic (P-wave Vibroseis) source points prior to hydraulic fracture stimulation of the well. Data was recorded via a fiber optic DAS cable cemented behind casing then processed using a diffraction summing algorithm. The resulting image is a depth image with the top of the image at an elevation of -7,000 ft.



HALLIBURTON CO.

Pictured is an illustration of fiber optic installation at a pad.

well is all about increasing the permeability in a rock to provide a pathway for fluids and gas to move from the rock into the wellbore.

"An important question to ask is, 'What is the efficacy of my frac?'" said Brian Fuller, Sterling Seismic's vice president of reservoir geoscience. "You put $100,000 to $200,000 per frac stage into a well, maybe do 30 to 40 frac stages in a well, [and] before long it adds up."

One of the ways engineers analyze the efficacy of a frac is to see how much oil and gas is coming out of a reservoir that can be attributed to a specific frac stage.

"It's an inexact science," he said. "It's hard to see how much fluid is coming from a specific frac stage. You may have five to 10 perfs in a frac stage but not know exactly how much fluid is coming out of an individual perforation or group of perforations."

The microseismic method uses seismometers or fiber optic sensing to detect microearthquakes associated with fluid pumped into the borehole and reservoir. The microseismic events may indicate how far fluids and proppants are going out into the reservoir. Using microseismic, the question of whether the sand is propping open the fracture remains unclear, however, Fuller said.

"Not every microseismic event is a place where proppant has gone into the reservoir," he said, but it "offers clues" about how far from the wellbore the sand may have traveled.

A third method, coring, involves placing colored proppant downhole in different frac stages and seeing where different colored sand ends up after the post-frac core is extracted from the reservoir. While expensive, it makes it possible to "really put your finger on how many fractures were generated," Fuller said. At the same time, coring doesn't shed as much light on the full dimensions of fractures, he said.

It is important not just to know fracture length and height, but also how wide they are. And those fracture widths can change over time, Fuller said.

Another way to gauge frac efficacy has been trial and error, said Delaney Leigh, senior product champion for production enhancement at Halliburton Co. Operators evaluated fracture efficacy in the unconventional market with "the best information available," she said.

But waiting on production to see which frac designs are more productive means a long learning curve. "They could have 100 wells before they understand the impact of the design," she said.

On top of that, uncontrolled variables such as rock properties, parent-child well relationships and inconsistencies on how jobs are executed also come into play, she said.

"In most cases, when comparing fracture designs, operators are considering if a stage was successfully done or not based on what they're seeing at the surface," Leigh said. "There is little visibility into what's going on downhole."

But intelligent fracturing can help change that. Integrating subsurface insights, automation and machine learning gives real-time visibility and control over fracture outcomes, she added.

One way to gain visibility downhole is through distributed acoustic sensing (DAS), which uses fiber to provide direct measurements of downhole conditions up to the surface.

An instrumental approach

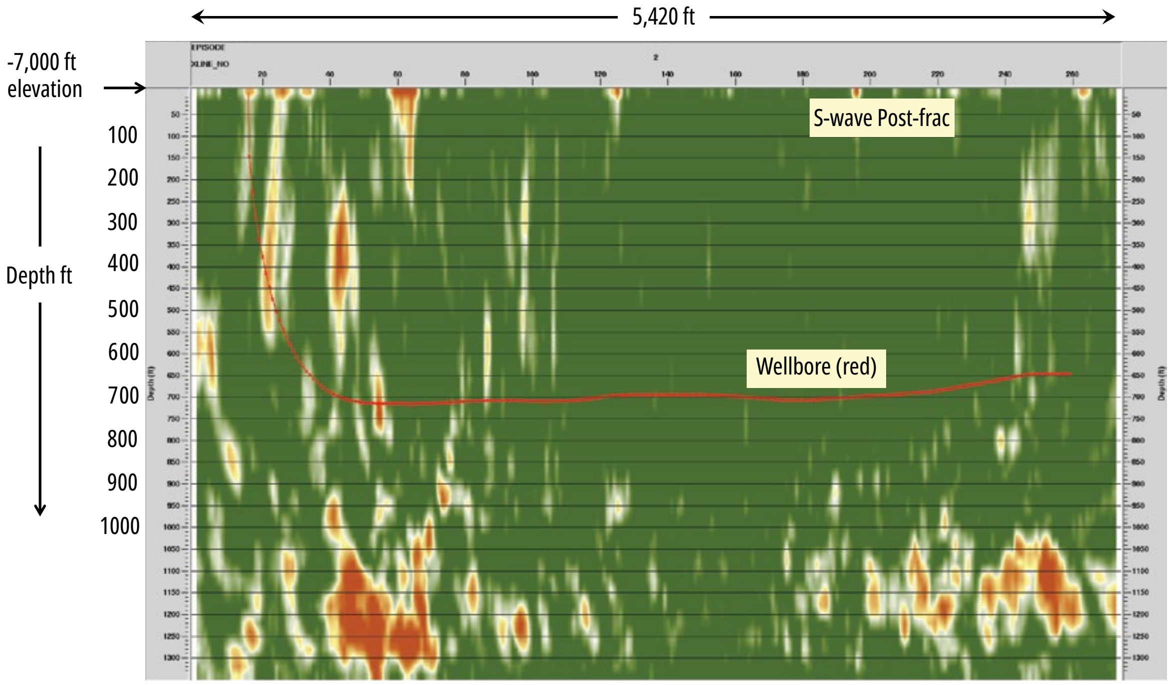
Instrumenting wells with diagnostics and real-time analytics can solve for subsurface uncertainty and accelerate the learning curve, Leigh said.

In the past, fiber optics have been cost-prohibitive and operationally complex. Successfully placing fragile glass into a wellbore was not something that could be done on a broad scale in the past, Leigh said.

"That's changing, and it's changing pretty quickly," she said.

The cables going into the ground now are a scalable solution at a fraction of the cost compared to three years ago, she said.

Halliburton has invested a lot of R&D effort and money into making fiber optics a scalable technology for routine



Source: Sterling Seismic

This image shows post-fracture S-wave diffraction. The second time-lapse seismic survey was recorded four months after the well had been hydraulically stimulated during which time flowback and production operations were executed. Data acquisition for the second survey was as near to identical as possible to the baseline survey data acquisition. The seismic data were processed in a surface consistent manner and the same diffraction summing algorithm was applied to the second survey as in the first survey. The post-frac shows significantly more and higher-amplitude diffraction events than the pre-frac.

downhole use. Part of that effort has focused on making sure the fiber optics are easier to install. The installation planning and preparation time has decreased from months to weeks, she said.

"We're optimizing the cable design to survive the operation it's designed for," she said.

Now, she said, the cost is less than half of what it once cost to be run in a horizontal well, and it can be done in less time as well.

Halliburton's solution uses mapping sensors to locate the position of the fiber optic cable in the well to eliminate an additional wireline mapping run. Leigh said these sensors ensure perforating guns can orient away from the fiber cable.

The fiber optics monitoring has "come a long way," and more operators use the technology as part of their routine completion approach, she said.

"The future is bright. They use downhole sensors to understand how fracs are performing," Leigh added. "Having DAS and DTS [distributed temperature sensing] information gives you a direct subsurface measurement of where your frac fluid is going in the well."

But having that knowledge is only part of the equation. The other part is how quickly the operator acts on that feedback, she said.

Halliburton has integrated measurements and automation to react to fracture behavior in real time, she said, adding that the real prize is the ability "to respond to what's going on in real-time downhole on location while pumping."

The combination has allowed operators to reduce the learning curve from months to minutes, which makes "better fracs on every pad by knowing what's happening in real time and acting on it," Leigh said.

Halliburton's SmartFleet intelligent fracturing system, commercialized in 2021, uses intelligent automation that relies on the improved fiber optics and real-time analytics to help operators see and control the efficacy of their fracs.

The result, she added, is better fluid distribution across the entire lateral as well as improved well economics. According to Halliburton, SmartFleet operations have improved the uniformity of fluid distribution across perforation clusters by 20% on average while also enabling operators to remove redundancy in completion costs. This reduces their average completion cost by 15%, the service company said.

In one Permian Basin deployment, an operator wanted to reduce fluid usage and screenouts. SmartFleet reduced the volume of fluid pumped from 70 bbl/ft to 60 bbl/ft for a total of 110,000 bbl less water per well and 20 hours less pump time while reducing screenouts by 50%, according to Halliburton.

In another Permian deployment, the operator wanted to increase stage length to reduce interventions, time and cost. Using SmartFleet increased stage length by 80% and resulted in 50 hours less on location. It also increased fluid distribution across clusters by 30%, according to the service company.

"When operators can see and control what's going on in real time, they can make better choices that affect the entire cost of ownership," Leigh said. "In a perfect world, we would have distributed sensors in every well, strapped to every string of casing that goes downhole."

Changes over time

DAS data is critical to Sterling Seismic's approach to evaluating frac efficacy. The company uses artificial intelligence (AI) assisted data processing technology based on the diffraction and reflection of seismic waves to generate seismic images around the wellbore. The resulting images can be combined with rock mechanics analysis to measure changes over time in reservoir characteristics like pore pressure, rock stress, stress direction and fracture density.

By processing wave diffraction data before and after a frac job, Fuller said, it's possible to get a time lapse view of the number, location and size of fractures. Time lapse DAS reflection data and rock mechanics can also be used to estimate production-induced pressure drawdown.

The AI technology can then analyze that data to locate "where most of your fracture energy is," Fuller said.

As such, it can also show a lack of events to identify potential targets for later refracs. The same approach can also be used throughout the life of the field, he said.

That time lapse approach can provide additional information, such as where fluid is entering the borehole and where in the reservoir it is coming from, he said. It's possible that it can also answer crucial questions such as fracture width, he said.

"Is it a millimeter or 100 millimeters? We're getting there," Fuller said.

In terms of the methodology's accuracy, there's not a perfect overlay of P wave and S wave over compressional and shear wave diffraction images, he said.

"The real world's not that simple," Fuller said. "There are a lot of places where they overlay nicely and some places where I see one and not the other."

Further, he said, "I don't have direct evidence that what I'm seeing is a wide fracture versus a thin fracture, but according to modeling, we should be able to see the amount of energy that comes from a diffractor is a function of the type of wave and the width."

Sterling has been working with fiber optics company Ziebel.

"Ziebel does a lot of passive listening for reservoir gurgling," Fuller said. "Where there's a lot of gurgling or low-amplitude seismic signals, it is assumed that fluids are entering the borehole."

And as long as there is fiber in the borehole and a seismic source at the surface, Sterling can apply the AI-based technology.

Because reservoirs change over time, Fuller said, this type of assessment can provide operators a lot of value.

"Fractures open and they close," he said. "If there's pressure drawdown in one area of the reservoir, then stress is reduced elsewhere."

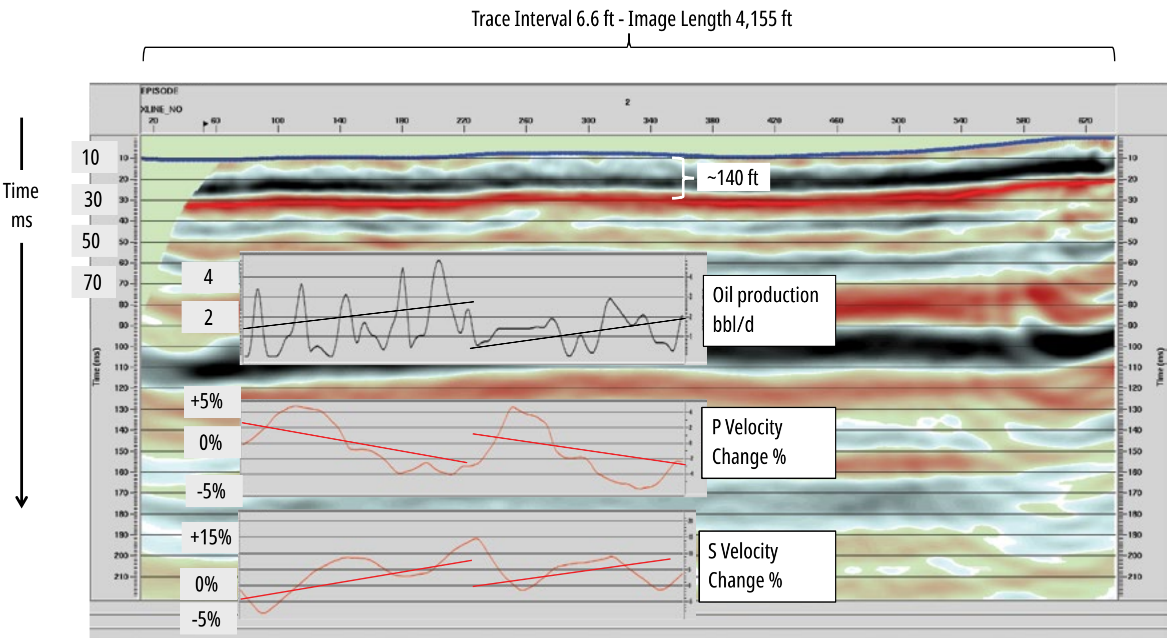
Fractures may have been closed in a high-stress area, but the fractures can open in response to the reduced stress, he added. As such, it could lead to production in other areas.

"These reservoirs change over time, and where fluids are coming into borehole changes through time," Fuller said. Repeating the assessment of a wellbore over time helps show where those changes are happening.

"If at one time a well produces from one location but another part of the well never sees production, then there is potential to profitably refrac that nonproductive area," he said. "We know there may be virgin production we've never even touched there."

Sterling has applied this technology to fields in the Midcontinent basins, so the next step is to commercialize it.

"It's clear we have something here," Fuller said. "We want to learn more, get more people and companies involved in it." OGI



Source: Sterling Seismic

This image shows time lapse seismic reflection and time-lapse velocity changes compared to production rates. The same Vibroseis dataset that was used to produce diffraction images was also used to produce time lapse reflection images below the well.

CHAMPIONX

EMERGING TECHNOLOGIES AIM TO FURTHER OPTIMIZE US PRODUCTION

Upstream companies working to boost production responsibly and affordably are being aided by groundbreaking new products that are reimagining the future of supply.

ARTICLE BY
HART ENERGY STAFF

Above, ChampionX's plunger lift tools help operators in tight oil plays optimize production economics as horizontal wells mature and product output begins declining.

Growing political turmoil and record-breaking gas prices are reigniting the demand for responsibly produced domestic oil and gas. New technologies are helping the energy sector answer that call. Many of the products being launched are paired with existing equipment or infrastructure to help companies optimize production economically while meeting ESG goals.

Whether it's a technology that is lowering carbon emissions from chemical management programs or optimizing production with artificial lift systems, innovative products throughout the industry are helping operators do more with less.

"The key to creating real, adoptable change within the industry is to recognize the importance of steady, iterative improvements to existing technologies," said Julie Fidoe, director of marketing for production chemicals at ChampionX, a global oilfield service company. "One of the things the chemical technologies business has always been focused on is partnering with our customers to honestly evaluate current operations and products to focus innovation on immediately employable enhancements that move all of us closer to our future goals."

Lower costs, lower carbon

ChampionX is among the companies committed to sustainably focused innovation. After acquiring Tomson

Technologies in late 2021, it launched a nanotechnology platform to enhance the performance of existing production chemistries. When applied to its Total Scale Management Program, the technology has demonstrated a 300% extension to the historical scale squeeze lifetime in more than 150 applications to date. As a result, the XR (extended release) portfolio provides a reduction in required well intervention, and with that, a decrease in associated operational maintenance expenses and carbon footprint.

"That means operators benefit from reduced TCO [total cost of ownership] and carbon footprint associated with three times fewer chemical injection requirements over the lifetime of the well," Fidoe said. "Additionally, by enhancing scale control, we are increasing the amount of protected oil produced. Ultimately, this technology drives all our ESG goals by supporting efficiently and responsibly produced oil and gas reserves while maintaining profitability.

"While we have been working on these developments for decades, this is worth talking about right now because it shows how we are helping companies do more with less—and that's a fundamental of true sustainability."

Pumping up the progress

To help those working in unconventional plays operate more efficiently, ChampionX has introduced several technologies for electrical submersible pumping (ESP) systems. The Woodlands, Texas-based company launched its new High Rise series pump line this year. The line achieves up to 33% greater lift per pump, helping to minimize rig time while reducing carbon footprint.

"The Oculus technology that's integral to the High Rise hydraulic design provides greater lift with fewer actual pumps," said David Baillargeon, engineering supervisor for ChampionX's Unbridled ESP Systems. "Wells that previously required five or six pumps now need just three or four to achieve the same amount of lift. There's a benefit to that: a 1-ton reduction in carbon emissions and 20% fewer heavy metals per ESP install with the High Rise pump line versus previous technology."


CHAMPIONX

The AnX coiled rod technology could help improve rod string run times in challenging well conditions, keeping production online and reducing the need for repairs caused by corrosion.

Another advantage of the new pump series is greater gas handling capabilities, he said, adding: "Gas interference in ESPs is a significant challenge, and based on extensive testing, we have documented that High Rise pumps can handle up to 52% free gas."

Baillargeon also noted that the new pump line has a wide operating range—200 bbl/d to 7,500 bbl/d—and improves pull strength by 40%.

"This is important in the unconventionals where the flow rate changes rapidly," he said. "A wider operating range helps avoid system changeouts as production declines. And, greater pull strength helps mitigate the potential to part a unit downhole while extracting an ESP from these deviated wells."

Performance gains

ChampionX's new technologies often focus on helping customers achieve performance gains through incremental design improvements and application engineering. For instance, through its plunger, lubricator and bumper spring designs, ChampionX plunger lift tools now extend to wells capable of producing up to 300 bbl of fluid a day—an increase that expands the plunger lift's application range.

The boost is especially impactful in tight oil plays such as the Permian Basin and Bakken Shale, where plunger lift can help optimize production economics as horizontal wells mature and production output naturally declines.

"Solutions like this can be very significant when you multiply it across a number of wells in an operator's field," said Brent Cope, plunger lift product line manager at PCS Ferguson, a ChampionX business unit. "Production from each well is more consistent, and the plunger reduces flowing bottomhole pressures to sustain maximum daily rates."

In April, ChampionX's Edmonton, Alberta-based business unit, Pro-Rod, launched another such potentially impactful technology: AnX coiled rod. The technology features a continuously applied, patent-pending coating that actively prevents corrosion to the underlying steel coiled rod.

The results are improved rod string run times in challenging well conditions, keeping production online and reducing the frequency of workovers to mitigate corrosion-related damage to the rod string and other downhole equipment, said product line director Alex Perri.

"The early results have been very promising in wells with corrosive and abrasive conditions," Perri continued.

Boosting production

Locus Bio-Energy Solutions manufactures biosurfactants—fermentation-produced, zero-carbon chemistries used in numerous upstream and midstream products. Considered more versatile than traditional surfactants and other bio-based surfactants, biosurfactants today represent a $4 billion a year global oilfield market.

Locus produces biosurfactants at scale that are tailored for a multitude of applications, including completion and stimulation formulations that can release more trapped oil. The biosurfactants, which are the size of human DNA, are injected into conventional or unconventional reservoirs, lowering interfacial tension and contact angle, which enables production of residual oil. Their nanoscale molecule size allows them to reach the nanopores and fractures of reservoirs that typical surfactants could not.

"This is absolutely unique," said Locus CEO Jonathan Rogers. "These biosurfactants were known for about 50 years-plus, but previously they were only viable commercially for the personal care industry or high-end cleaners. Now, at Locus, we have a lot of intellectual property rights around novel fermentation processes that can produce these at volumes needed for use in the oil and gas industry. And we can make them at the price point that allows us to design truly innovative oilfield chemistries with results you just can't get with other surfactants."

The chemistries also help companies achieve their ESG goals, as the biosurfactant ingredients are fully biodegradable, zero carbon, sustainable (made from sustainably produced agricultural products) and can boost the amount of production at a given shale well, Rogers said. Since companies can yield more production from a single well with the product, they would be required to frac less wells to meet production goals, he added.

"It's a very low-carbon way of getting more out of existing assets," Rogers said. "It's a game changer. One of the things people don't realize is that these types of solutions are out there. With all the crises we've got in the world now, the realization is we can have domestic security and also have the lowest carbon barrels anywhere in the world."

The company has treated more than 300 wells since launching the biosurfactant-based products in 2018, and their customers have realized significant production increases and returns on investment. In some applications the biosurfactants require lower dosage rates (as little as two-thirds in frac fluids, for example) to work, Rogers said.

Locus biosurfactants are also helping companies with the ever-growing challenge of saltwater disposal. Every barrel of oil that is produced is accompanied by about 7.5 bbl of saltwater as a byproduct. Finding ways to dispose of this water safely and responsibly has been a challenge for many operators, and Rogers said his company has developed biosurfactant-based products to help address these issues.

While producers are continuing to increase water reuse and recycling, there will continue to be a large need for sequestration of produced water in saltwater disposal wells. Locus has developed a product that Rogers said can reduce injection pressures by up to 20%, with 70% faster filtration in laboratory testing. The technology, he said, has proven to be an effective way of sustainably and affordably disposing produced water and can also provide benefits to saltwater disposal well operators by reducing oil carryover and recovering more skim oil.

LOCUS BIO-ENERGY SOLUTIONS

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It all comes back to using new biosurfactant-based products in existing assets to meet or exceed ESG goals, Rogers added.

"We want the oil and gas industry to know that you don't have to sacrifice cost or efficiency," he said. "In fact, you can reduce your cost, increase your efficiency and profitability and be sustainable at the same time. It's a win-win situation."

New technologies are helping the energy sector answer the demand for responsibly produced domestic oil and gas.

LOCUS BIO-ENERGY SOLUTIONS

Locus Bio-Energy Solutions chief executive Jonathan Rogers (left) speaks with a researcher. The Ohio-based company's nature-derived biosurfactants are recognized around the world for outperforming traditional oilfield chemicals.

The energy evolution

Deloitte's "2022 Oil and Gas Outlook" report highlighted how emerging innovations are playing a role in reshaping oil and gas companies as the energy transition continues. It noted how some industry giants, such as Halliburton Co. and Baker Hughes Co., are working to accelerate groundbreaking technology as part of wider diversification efforts.

"However, digitalization will only help to a certain extent," the report noted. "The sector needs to get even leaner and greener. Providing integrated solutions for decarbonizing upstream projects, implementing subscription-based revenue models or diversifying into the low-carbon space could be key enablers of the future [oilfield service] strategy."

Artificial intelligence is playing a significant role in the energy shift, with some industry companies utilizing them as part of a wider commitment to eliminate emissions and identify efficiencies.

"Companies like bl [Plc] and Shell [Co.], which have both pledged to achieve net-zero carbon emissions by 2050, are under increasing pressure to minimize their carbon footprint in compliance with the Paris Agreement," according to a Report Linker report. "Shell is employing AI [artificial intelligence] technology to do predictive maintenance of individual pieces of equipment or entire systems to reduce their carbon footprint. This allows the corporations to foresee and handle probable equipment faults before they occur."

Top trends

Upstream companies in the market for new products are often searching for technologies that solve one of three problems, said Sriram Srinivasan, senior vice president of global technology at Halliburton. A top priority for operators has been discovering technologies that will reduce the extraction costs of hydrocarbons, he told Hart Energy.

"This will allow oil and gas to remain a competitive option in the energy mix for years to come," he said. "I'm especially excited about technologies that reduce extraction costs where digital technologies will play a key role. For example, in drilling, technology that will allow us to improve efficiencies in well design and plan better wells using past data or experience. Drilling automation technologies will allow Halliburton to drill faster and better quality wells, which will reduce costs during drilling and subsequent completion activities."

Hydraulic fracturing is another area where automation can be used to reduce costs for both service companies and operators, he added.

Companies are also on the lookout for technologies that help operators increase production from existing assets, and technologies that will help lower the cost abandonment of declined wells.

"As the portfolio of declined wells becomes large, operators must deal with them at lower cost," Srinivasan said. OGI


SOLVAY

MIDSTREAM CAPACITY KEY TO SURGING PRODUCTION

Water in and out as well as hydrocarbon transport sustain new completion techniques.

ARTICLE BY
GREGORY DL MORRIS
CONTRIBUTOR

Midstream capacity is widely seen as an important enabling factor in expanding U.S. hydrocarbon production, especially in unconventional plays.

"What we see from the drillers and the pressure pumpers is that the activity is focused in the major basins," said Jonathan Godwin, senior associate at Enverus. "The Permian alone accounts for 60% to 70% of all the new production we are seeing this year and next."

For example, optimizing existing assets was a major reason why Crestwood Equity Partners acquired Sendero Midstream Partners. Crestwood owns and operates gathering and processing midstream assets as well as storage and logistics primarily in the Williston Basin, Delaware Basin, Powder River Basin and Marcellus Shale.

On July 12, Crestwood closed a series of transactions in which it acquired Sendero Midstream Partners for $600 million in cash and First Reserve's 50% interest in Crestwood Permian Basin Holdings for 11.3 million Crestwood common units. Separately, on July 1, Crestwood completed the divestiture of its Barnett Shale assets for $275 million in cash. As a result, Crestwood has significantly expanded its operations in Eddy County, N.M., one of the most active counties in the contiguous U.S.

Current trends are expected to continue.

"As we get exposure to higher prices, especially for gas, we are going to see even more demand development because producers have access to midstream exits for their molecules," Godwin said. "That is especially the case when there is [liquids] weighting because that adds value."

Godwin noted that while higher prices create demand for activity, there is a mitigating factor.

"Frac crews and rigs are nearly fully utilized, and there appears [to be] little relief before 2024 for the market to loosen," he said.

Another factor is the type of producer.

"Of the rigs running now, at least 55% are in service to private developers," Godwin said. "Their inventory is lower relative to the large and even mid-sized public producers. The privates are more sensitive to price, so they are the ones bringing on more rigs sooner."

Private practices

Private producers, some relatively small, are also more inclined to take advantage of existing midstream capacity when planning their drilling programs. They generally don't have

> **"As we get exposure to higher prices, especially for gas, we are going to see even more demand development because producers have access to midstream exits for their molecules."**
>
> —**Jonathan Godwin,** *Enverus*

capital to build out their own gathering and processing systems and may not have additional volumes on their own to warrant midstream operators to invest in new capacity.

Godwin explained that advances in hydraulic fracturing techniques have also taken advantage of ready midstream capacity and capability.

"Initially wells were completed one at a time," he said. "The development of zipper fracs, where wells would be completed in pairs, was a huge increase in efficiency. Now with the cube, or wine-rack approach, anywhere from six to 20 wells on a pad can be completed in sets using simul-frac operations. Four at a time is most efficient, cutting total pumping time by 15% to 25%; and pumping charges are probably the single biggest expenditure."

Notably, cube development often includes water.

"That is where the midstream comes in," Godwin said. "They have to deliver water to the well to support these multiple simultaneous completions. The pumpers have their side of things down, but they lose efficiency if they are waiting for a water tank to fill."

Sand deliveries can also be a constraint, but that is not a midstream service.

Then the pipe has to be in place for big initial production of water, gas and liquids.

"Midstream is important for both delivery and disposal," Godwin said. "Recycling of produced water is more prevalent than ever, and it is an easy win both in terms of completion efficiency and ESG reporting."

"In the second half of 2022, we've got growth in all of our basins, particularly the oil-weighted ones: the Bakken, the Powder River and the Delaware-Permian, especially in New Mexico."

—Diaco Aviki,
Crestwood Equity Partners

Riding the Permian crest

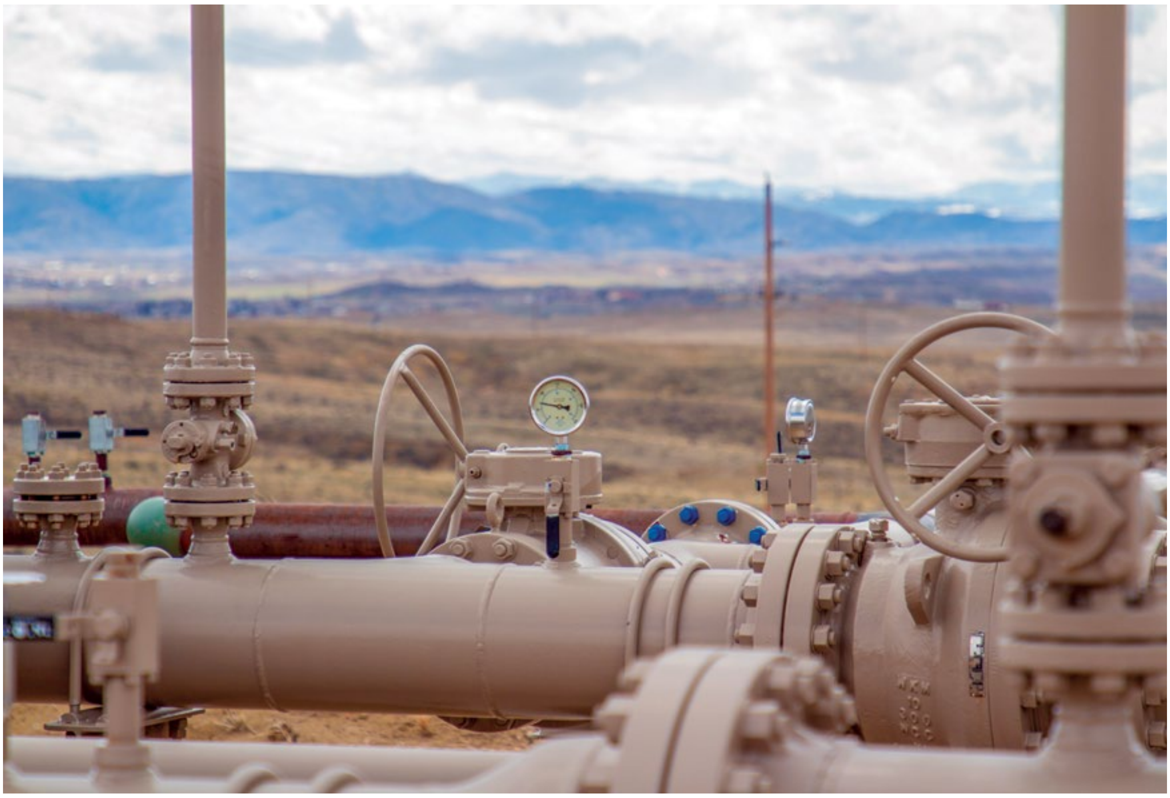
Spending more than 20 years on the producer side before moving to the midstream sector with Crestwood four years ago, Diaco Aviki, COO, explained that as producers plan to increase production, "returns and logistics matter," as well as the economics of each well and field and readily available midstream capacity.

"I've never seen better coordination between shippers and carriers than what I'm seeing these days, even when I was on the producer side," Aviki said. "Part of that is because lead times for midstream materials and equipment have gotten significantly longer, especially for electrical, computing and compression facilities. In recent years, we could just purchase items out of storage or rent compressor units as we needed them. That is not the case any more. We are buying for future activity and doing what we can to reuse existing equipment and move components from an inactive to an active basin.

"We've had producers in the Delaware Basin contact us in advance of issuing a formal request for proposal, just to

CRESTWOOD EQUITY PARTNERS

The Herradura compressor station is Crestwood's newest station, with capacity of more than 100 MMcf/d. It was commissioned in April.



Crestwood's Jackalope gathering system is located in Douglas, Wyo., in the Powder River Basin.

understand our available capacity well into the future. I've never experienced that before in my career," he said.

Impacts of growing production

Another important driver for that coordination is the upstream sector.

"Most of the drilled uncompleted [DUC] inventory has come down in the past two years," Aviki said. "There are still a few DUCs around but that is specific to some producers. Energy Information Administration data show that the disparity between drilled and completed wells is closing."

As producers move through their inventory from DUC hunting to infill drilling and in some cases on to step-out development, the upstream lead time also gets longer as well as more expensive. That increases both the opportunity and the need for close collaboration with the midstream industry.

"In the second half of 2022, we've got growth in all of our basins, particularly the oil-weighted ones: the Bakken, the Powder River and the Delaware-Permian, especially in New Mexico," Aviki said. "That has really ramped up. In that territory we are primarily a gas-gathering operation.

"Infill drilling is where most of them are at these days," he added. "That varies greatly by operator, with the private equity portfolio producers moving faster. There is one PE-backed operator that has 19 rigs running. That is a massive program for the operator to keep up with and coordinate with their midstream providers. We have seen a steady pace of step-outs, notably in the acreage of Sendero Midstream Partners, the acquisition that closed in early July."

Hitting all-time highs

The action is in the major plays, said Steve Hendrickson, president of Ralph E. Davis Associates, an Opportune company.

"For oil, those are the Midland and the Delaware basins in the Permian, also the Bakken and the Eagle Ford," he said. "For gas, those are the Haynesville in both Texas and Louisiana, as well as the Marcellus-Utica. Recently, I've heard the Permian is hitting all-time production highs. In the Haynesville and Marcellus core areas, the recent indicators are up from actual wells drilled to permits."

In the Bakken in particular, Hendrickson noted that "in some cases, we have seen improved performance, even as spacing got tighter, rather than the level of EUR degradation that we often do. That could be from improvements in completion technology or perhaps from beneficial interaction among the wellbores. That seems unlikely but may be possible."

Currently, producers are able to proceed as they wish because "in general there are not the level of midstream limitations we observed in many plays a few years ago," said Hendrickson.

That said, he is keeping tabs on planned growth in LNG exports in the medium term.

"We are already bumping up against 12 Bcf/d of LNG exports, and according to published data we've seen, the FERC [Federal Energy Regulatory Commission] has approved more than 20 Bcf/d of new construction and expansions," Hendrickson said. "I don't know how much of that has reached FID [final investment decision], but I've got to believe that a lot of it is going to happen, especially given Europe's commitment to reducing their exposure to Russian gas imports."

The development of water as a midstream business continues to trickle along.

"In areas where there are more numerous, smaller producers, there is a midstream opportunity for water banking."

—Steve Hendrickson,
Ralph E. Davis Associates

"Circularity is definitely happening, especially for the large-footprint operations with a lot of rigs running," Hendrickson said. "In areas where there are more numerous, smaller producers, there is a midstream opportunity for water banking. That makes a lot of sense, even with the capital and regulatory challenges."

Despite the obvious economies of scale in putting three pipes in a ditch—gas, liquids and water—Hendrickson noted that there remains a fundamental difference in the water business as distinct from moving hydrocarbons.

"Water infrastructure is a relatively low technology, a potentially low-margin operation, so it would surprise me if the big operators got heavily involved," he said. "I would expect them to focus more on processing and transportation projects that I expect would deliver higher returns."

Increased production, through a combination of infill drilling and step-out development, has been most evident in the north and west areas of the Delaware Basin. There has not been much recompletion work, even in the Barnett Shale, which was something of a surprise to Crestwood's Aviki.

In all, "available midstream capacity is definitely informing decisions by the upstream industry to increase production," he said. "Coordination between upstream and midstream has never been more critical. Two significant factors in that are the supply chain challenges and the importance of environmental, social and governance factors. It is now more important than ever to execute growth with the least carbon footprint."

Improved completion approaches

Crestwood recently completed a 100-MMcf/d compressor station in the Delaware Basin that includes several features tied to its carbon management plan, such as improved emissions detection and capture technology.

"We will be using this facility, along with the Sendero capacity, to optimize the combined system for shippers of both legacy companies," Aviki said.

Technology, both upstream and midstream, is part of the capacity and operational improvements. "Tech continues to surprise to the upside," he said. "There have been so many improvements in drilling and completion that have significantly lowered breakeven points and improved capital efficiency."

As an example, he cited 3- to 4-mile laterals.

"Those are such game changers," Aviki said. "They unlock so much acreage and give a much longer runway, especially in the Bakken as rigs move to the west. There is also a better approach to spacing and the fine-tuning of sand and water."

As evidence he noted that type curves in the Bakken have been improving every year.

"That is very unusual. We normally see type curves decrease over the years as the top acreage is produced."

In terms of midstream technology, Aviki mentioned several that might seem modest but have made a significant difference for Crestwood.

"We originally had one skid each for gas, oil and water," he said. "Now we have one skid for all three. That improves efficiency and lowers our footprint on the landowner's property."

Crestwood has also installed variable-frequency drives on most of its pump motors. That enables the carrier to optimize pipeline flow and reduce its carbon footprint through lower energy consumption.

"The cube development, or wine rack, that producers are using has helped us with scale through capital and operating efficiency from a compression and pipeline perspective," Aviki said. "We can build our facilities once for the anticipated volumes now and in the future and not have the capital inefficiency of installing duplicate compressors facilities and pipelines as production increases."

Efficiency is also the watchword in water.

"Our business is seeing increased activity and production among both our Midland and Delaware basin customer base," said John Durand, president and chief sustainability officer of water midstream company XRI. "Operators are balancing great capital discipline along with implementing their core drilling plans for this year. Given the current pricing environment there appears to be more willingness to look at step-out and recompletion activities as well.

"There are certainly opportunities for future capacity growth, and as an industry could see more need for capital to be expended for new projects and existing asset expansions, particularly as we head toward 2023, based on industry analysis and expected strong demand," Durand said. "I see all sectors demonstrating increased drilling and operational efficiencies to improve lifting costs per barrel."

What makes the water midstream sector so compelling, he said, "is the fact that prudent water management remains so critical in maintaining and growing production across the Permian Basin. As upstream operators continue to outsource water management expertise, third-party water management companies are continuing to create operational and economic efficiencies," for all parties. OGI

EMISSIONS-REDUCING TECHNOLOGIES EMERGE AS WELLSITE PRIORITY

Producers and service providers focus on reducing their reliance on diesel fuel and identifying and mitigating green-house gas leaks.

ARTICLE BY
BRIAN WALZEL
SENIOR EDITOR

A combination of favorable market factors, including higher and stabilized commodity prices, proven returns on ESG investments and a push to increase production, has created an environment in which shale producers are adopting emissions-reducing technologies at the frac site with greater frequency.

That rapid adoption of both greenhouse-gas reduction practices and new technology deployment could lead many companies with stated net-zero goals to achieve those aspirations by the middle of the decade.

According to a report issued by Wood Mackenzie, "Most Scope 1 emissions could be addressed by mid-decade, given progress companies have made already. Look for continued capex spend of more than $100 million per year for many companies to continue the significant reduction."

Methane and flaring emissions are quickly falling for many companies, as high natural gas prices have encouraged companies to sell associated gas rather than flare, while technologies being deployed at the well site are helping monitor, identify and even monetize leaked gasses.

For many companies, reducing their emissions profile starts at the well site even before production begins. Decreasing a reliance on diesel fuel for fracking equipment helps cut down on CO_2 emissions. And later during the production phase, knowing where leaks may occur and having the ability to predict when and where those leaks are helps bring emissions reduction efforts to the full life cycle of the well.

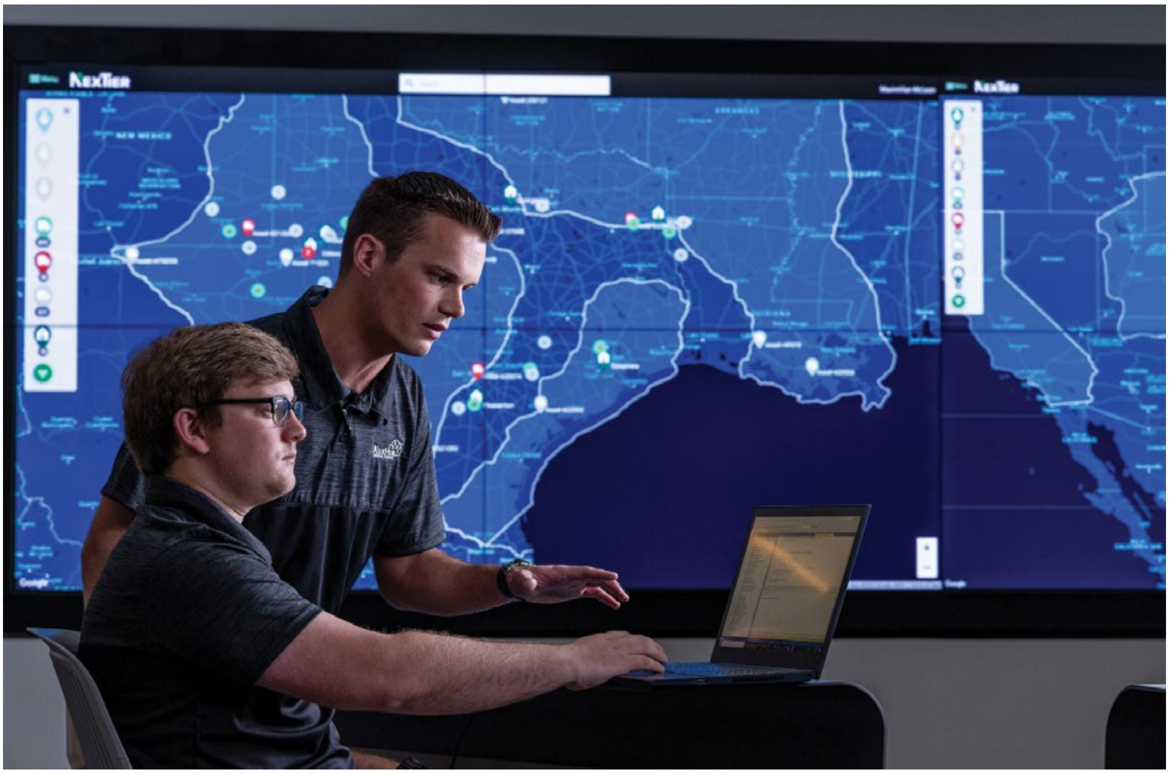
Alternative power generation

When it comes to reducing emissions at the frac site, perhaps no fruit hangs lower than cutting diesel consumption on frac fleets.

In August 2021, NexTier Oilfield Solutions announced its Power Solutions division, which includes the integration of its CNG supply and field gas handling technologies. The company has paired its CNG fueling and blending system


NEXTIER

NexTier's Tier 4 dual-fuel gas blending pressure pumpers utilize clean-burning natural gas to help offset diesel fuel use from traditional frac fleets.



NEXTIER

NexTier's NexHub Digital Center is a remote operations center that helps integrate activities across the full scope of the well site, including cementing, hydraulic fracturing, wireline and coiled tubing.

with its Diesel Displacement App, which provides real-time performance monitoring that shows how much diesel is being offset by NexTier's dual-fuel fleets.

"Visualizing means that we're able to improve, make immediate decisions and use data to actually drive how we're using the pumps, which all goes back to displacing more diesel with natural gas and lowering overall costs and emissions," said Ben Dickinson, NexTier director, quality and NexHub operations.

NexTier has emerged as a leader in providing Dynamic Gas Blending fleets in the U.S., which Dickinson said can help meet the needs of operators focusing on using as much natural gas as possible and lowering their emissions profile.

"Every client is interested in lowering emissions," he said. "Every client is interested in using more natural gas in order to lower overall costs. The conversation we have with clients is about how do we get there with the type of equipment that they would like to use, and also with the type of fuel source they have available in their region."

Dickinson explained that the NexHub application helps operators lower CO_2 emissions and reduce fuel costs by providing insights that maximize natural gas usage in dual-fuel frac equipment.

That equipment, according to NexTier, can use compressed natural gas and the operator's field gas at the well site, with both options providing a reduction in carbon footprint and lower cost compared to diesel.

Leading service companies are deploying fleets that utilize Tier IV dual fuel, or dynamic gas blending engines, and compressed natural gas (CNG) to help producers use less diesel fuel for fracking equipment.

Meanwhile, Midland, Texas-based Catalyst Energy Services' VortexPrime fleet features a direct-drive turbine technology powered by natural gas. The VortexPrime provides up to 15,000 psi working pressure and up to 25 bbl/min per pump.

"We take a military-grade turbine and we power it with natural gas," said Seth Moore, Catalyst executive vice president and COO. "We couple that to a drive train, and we turn a pump with it directly. So, we're not generating electricity or hydraulic power to power a mechanical pump. We're doing it directly. And that produces a very efficient exchange of the BTU [British thermal unit] of the natural gas down into a hydraulic horsepower. The difference is that we're not burning nearly as much liquid fuels."

Moore explained that upward of 93% of the fuel consumed at the well site is allocated for pressure pumping equipment. He said upward of 90% of that diesel consumed and being burned can be replaced by natural gas. A typical diesel-powered fleet could burn as much as 2,700 gallons of diesel per hour, Moore said.

"So, you're replacing diesel consumption with natural gas consumption, and natural gas is a cleaner burning fuel with less greenhouse gasses and less [nitrogen oxide]."

According to Catalyst, the VortexPrime fleet is fully self-contained and requires six to eight pumps versus a traditional standard fleet that might require up to 24 pumps. The company reports that a five-pump fleet can deliver 100 bbl/min of fluid at 10,500 psi while taking up 55% less space onsite than a standard fleet.

That smaller footprint helps lower a company's emissions profile as well, Moore explained.

"When you go from 24 pumps to eight pumps, then everything else starts shrinking as well," he said. "There's secondary and tertiary benefits of that. For example, the

CATALYST ENERGY SERVICES

Catalyst Energy Services' VortexPrime frac fleet utilizes a direct-drive turbine that helps operators reduce fuel consumption.

number of manifolds we need, all of the piping on location that is needed to hook up all of this equipment, there is less of that. It's maybe one-third of what it was before, so we have to purchase less of it, [and] we have to haul less of it. We have to repair and maintain less of it. We may not know how to quantify that, but the environmental benefits are not insignificant."

Managing emission leaks

Once a well is on production, harmful emissions can find their way into the atmosphere at any number of points along the production cycle. From lifting facilities to pipelines to separators to storage tanks, the production phase is one of the most critical components of every emission-reduction strategy.

EcoVapor Recovery Systems' variety of technologies helps reduce flaring by ensuring low-pressure gas can be sold at pipeline specifications, which also monetizes wasted gas.

ECOVAPOR RECOVERY SYSTEMS

EcoVapor's ZerO$_2$ E100 allows operators to maintain the economic benefits at lower production rates and still obtain the revenue and environmental benefits.

"Our whole business is centered around eliminating waste," said CEO Jason Roe. "When you look at things like flaring, venting of gas, even fugitive emissions of gas, that's wasted product our industry works hard to produce. We work hard to eliminate the flaring and venting of natural gas."

One of the technologies EcoVapor deploys is its ZerO_2 vapor recovery system that enables operators to capture nearly all of the low-pressure tank vapor. That captured gas can then be sold, Roe said.

"The tank battery can be a large source of emissions, whether it be flaring those vapor streams coming from the tanks, or worse, if it's just being vented from the tanks themselves," he said. "We purify these gas streams captured via vapor recovery units, which are these really high BTU-rich gas streams, so you can actually get a premium for it. So, where we play a role is the purification of these gas streams."

Roe described tanks as "in-breathing and out-breathing," and artificial gas blankets to keep air out could lead to an increase in the venting of that gas. "In-breathing," he said, can bring air, and thereby oxygen, into the tanks, which can cause corrosion, particularly in the downstream pipeline network.

"The pipeline network has pretty tight specifications on the amount of oxygen it will allow into the network," Roe said. "With that in mind, our core ZerO_2 product eliminates oxygen from these tank vapor streams, ensuring that 100% of this gas stream is moving to the sales pipeline."

With the price of Henry Hub hovering around $6/MMBtu, Roe said operators have been additionally incentivized with monetizing previously vented or flared natural gas.

"We have some operators that evaluate our products purely on an economic basis," he said. "By helping them to monetize the richest gas stream from their site without the concern of being shut in by their takeaway providers due to oxygen contamination, the economic case is very strong."

He also said that some operators just want to minimize their emissions by eliminating flaring, regardless of gas prices.

"A lot of times environmental solutions in the market today are asking operators to choose between economic performance and environmental performance," Roe said. "And fortunately for us, we don't force them to make that decision. They benefit financially as well as environmentally."

End-to-end solutions

Honeywell is in the midst of bringing to market an end-to-end portfolio of emissions management tools and technologies from field devices to site operational software to enterprise emissions monitoring platforms. The system would adopt Honeywell's existing battery energy storage technologies, renewable energy solutions and hydrogen and carbon capture technologies.

> **"Most Scope 1 emissions could be addressed by mid-decade given progress companies have made already. Look for continued capex spending of more than $100 million per year for many companies to continue the significant reduction."**
>
> *—Wood Mackenzie*

"We're very focused on getting some quick wins for our customers in reducing their emissions and also enable them to align with upcoming legislation, whether that be from the EPA [Environmental Protection Agency], whether that be financial reporting requirements from the SEC [Securities and Exchange Commission] and outside the U.S. within the European commission," said Adrian Fielding, general manager of emissions monitoring and reduction for Honeywell.

He said that effort has led the company to focus primarily on methane as the first greenhouse gas it wants to manage.

"Over a 24-year life cycle, (methane) is 34% more potent as a greenhouse gas than CO_2, and over 100 years, 25% (more potent)," Fielding said.

Among the systems Honeywell has introduced is its Gas Cloud imaging solution, which Fielding described as a video verification leak detection and quantification camera system. Another new technology deployment centers on continuous leak detection.

Fielding explained that current solutions often involve leak detection and quantification technologies, which offers periodic testing of anything that could potentially leak—primarily flanges, values and pumps.

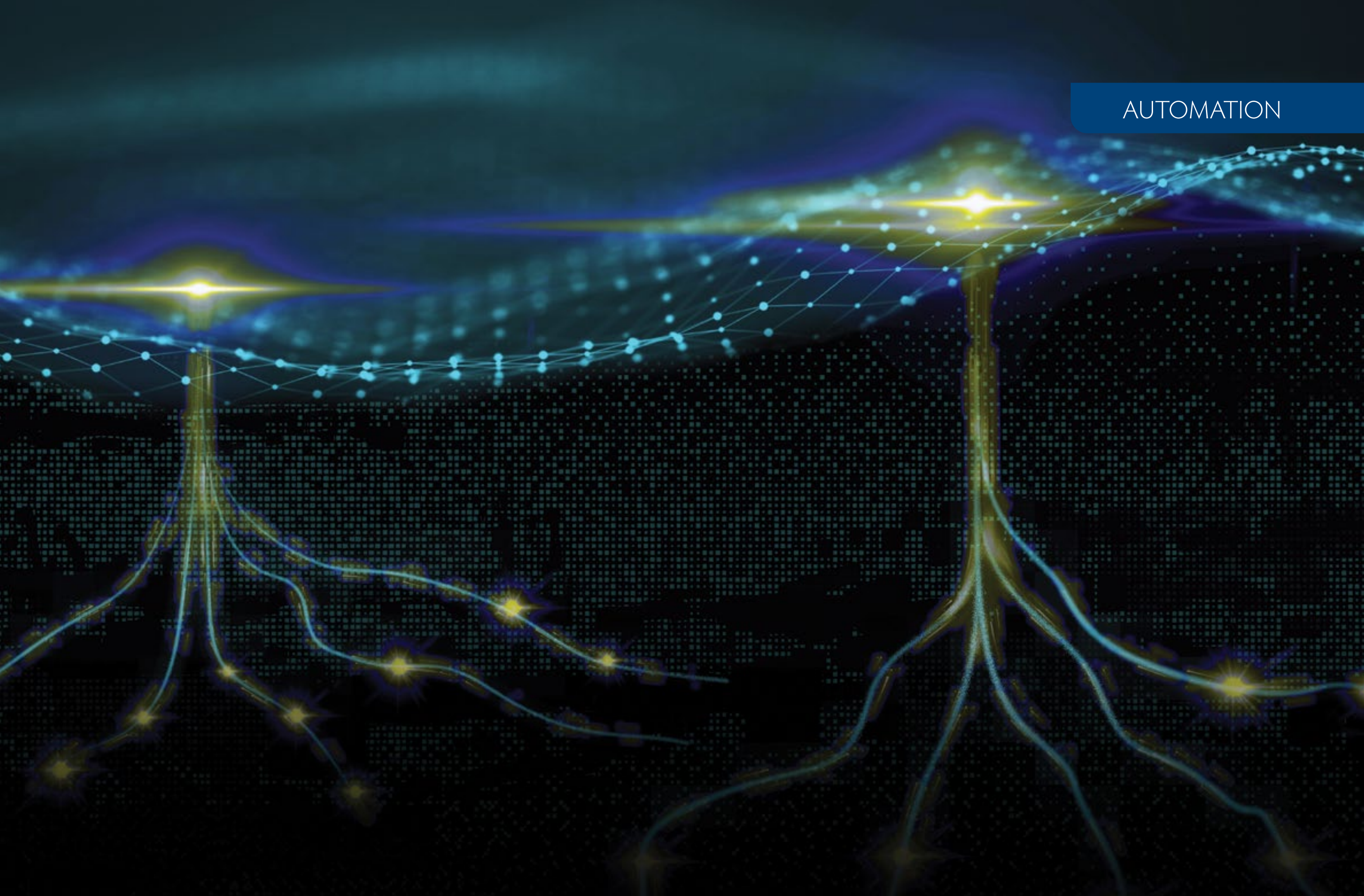
"We're going to supplement that solution with near real-time continuous monitoring," he said.

By adding continuous monitoring to wellsite components that are prone to methane leaks, "you're detecting the leak when it happens," Fielding said.

"If we were doing this and repairing it every time we saw a leak, then the downtime of operations would be quite significant," he said. "So for an operator, it's important to do a couple of things: try and align the repairs where it's cost-effective to do so and also to be able to trend and predict when they might need those repairs."

Meanwhile, Honeywell is also in the proof-of-concept stage for a version of its Rebellion Gas Cloud Imaging cameras that can be applied adjacent to a leak source.

"It's deployed in a swarm, so multiple devices, and because it's deployed in a swarm, the software analytics enable us to identify the potential leak source and give us a plus or minus 1-meter location, so that's pretty accurate," Fielding said. OGI



AUTOMATED SYSTEMS CAN SAVE OPERATORS FRACKING INEFFICIENCIES

Service providers Halliburton and Weatherford and data analytics company LYTT shared their automated technologies created to ensure efficiency in hydraulic fracturing operations.

WEATHERFORD

ARTICLE BY
MADISON RATCLIFF
ASSOCIATE EDITOR

Above, Weatherford combines single-cable simplicity and proven multi-sensor reliability with data quality and active reservoir insight, from single production zones fields to distributed sensing arrays in deepwater basins.

Automation has played a role in hydraulic fracturing operations for years but now more than ever is becoming essential in helping operators perform efficiently.

While digitalization practices were well-established before the COVID-19 pandemic, social distancing and lockdown requirements have given it a newfound importance. Since pandemic restrictions have begun to ease, most operators have continued to implement more automation systems due to the rising levels of efficiency they observed.

Hesitation around automating hydraulic frac operations stems from the misconception that automated operations equate to the operator relinquishing 100% of the control required to function. While automated services handle a lot of the execution without the help of humans, the human operators still make the decisions behind every action.

Tim Morrish, sales director for data analytics company LYTT, told Hart Energy that automation actually enhances control.

"If you have more information to make a smarter decision, is that not having better control of your process?" Morrish said. "We have this notion that AI [artificial intelligence] is going to make decisions, and this is something that it's not really heavily talked about, but if you do deep dives into AI, what you'll find is that artificial intelligence is still decades away from making actual decisions."

The benefits of digitalization range from convenience to life saving. While digitalizing operations handles a lot of the day-to-day tasks, allowing engineers to focus on engineering and increasing operational efficiency, it also can reduce the number of people required at a well site, lowering the chance of accidents and increasing safety.

Morrish emphasized that distrust in automation and digitalization is a hindrance to any operator expecting to remain competitive in the marketplace. The number of technologies and software systems being developed and implemented for hydraulic fracturing is accelerating and shows no signs of slowing down. Those who choose not to digitalize their operations to some extent risk falling behind and becoming obsolete.

To showcase some of their digitalization and automation technologies, service provider companies Halliburton, Weatherford and LYTT shared the technologies and services they are implementing to assist operators with hydraulic fracturing automation and outlined the attributes that set them apart from competitors.

Halliburton's SmartFleet and Zeus

Within Halliburton's portfolio of well optimization products, two of its systems help enhance hydraulic fracturing for operators through automation and electric fracturing: SmartFleet and Zeus.

Nearly two years after the launch of Halliburton's SmartFleet system in the Permian Basin, the company is continuing to see the benefits of the intelligent fracturing system's deployment as automation plays an ongoing role in completions operations.

"This year, there's a big automation push. It's being seen in everything," Shawn Stasiuk, Halliburton's vice president of the production enhancement product service line, told Hart Energy.

The intelligent frac system allows operators to visualize and control frac operations with intelligent automation and live subsurface measurements, while improving better decision making and consistent operations.

"SmartFleet is a way of automating the pumping operations during [drilling] to improve the downhole frac outcome," Sriram Srinivasan, senior vice president of global technology at Halliburton, told Hart Energy in an April interview. "So managing, treating pressure better, lowering the treating pressure, for example, of improving uniformity in how you perform—all of this with the aim that all of these things, if you do it right, will improve production in the future."

In addition to SmartFleet, the company's electric frac fleet, called Zeus, allows pumping at higher rates while simultaneously lowering carbon emission profiles and increasing wellsite safety. The unit operates consistently with 5,000 units of hydraulic horsepower, performing 30% to 40% higher than competitors, according to the service company.

Other components of Halliburton's all-electric frac spread include: a dual-manifold trailer that delivers up to 230 bbl/min and allows operators to complete more lateral footage with simul-frac operations compared to traditional zipper frac; the ExpressBlend fluid management system that eliminates failure points and improves completions efficiency; and the eWinch electric wireline system that offers improved safety and reduced footprint.

Although electric frac fleets are not new to the market, service providers like Halliburton have seen a large increase in their use due to their greater operational efficiency and sustainability, as e-frac operations can now leverage grid power, reciprocating engines and natural gas-powered turbines to run the pumps.

Therefore, the Zeus e-fleet gives operators who want to increase their environmental sustainability a leg up on their competitors. According to data from Halliburton, the e-fracs leave less of an environmental footprint than conventional frac fleets, with 45% fewer emissions when powered by the grid.

"With the increased performance and optimization from these technologies, we are seeing projects where automation and electric converge," Stasiuk said. "With Zeus, electricity runs the frac spread, so they save fuel and lower emissions at large, while SmartFleet automation optimizes subsurface outcomes like fracture placement.

"And this is really good for real-time emissions reporting," which in turn is helpful to investors placing a larger emphasis on transparency in emissions reporting.

The integration of digital and automation cuts a significant amount of time from the learning curve, which Stasiuk called "analysis purgatory," referring to the time it takes to acquire, interpret and implement data insights, which can take weeks to months. However, with operators able to see and control fracture performance while pumping, the adoption of real-time fracture optimization is moving along at a much more rapid pace.

Weatherford's ForeSite Sense

Real-time reservoir monitoring practices lead to better operational efficiency, as well as increased safety at the well site due to operators being able to assess well and reservoir performance live and make adjustments as needed.

With that in mind, Weatherford wanted to develop a continuous monitoring system that allowed operators to access data to enable them to make quick, effective well decisions.

ForeSite Sense reservoir monitoring provides downhole real-time continuous monitoring that will determine "true reservoir behavior," according to Weatherford global product line manager Julio Bello. It features an optical flowmeter scalable to any pipe size with a bi-directional flow rate, and distributed fiber optics sensors (DFOS) help with hydraulic fracture profiling, passive seismicity, flow profiling, vertical seismic profiling and wellbore integrity monitoring.

Weatherford applies project evaluation and project assessment to the data integrated system, Bello told Hart Energy.

"We deploy the system—talking about downhole hardware—and innovation to use foresight to deliver real-time data and transfer that data to the process, interpreted by our partners. Then, the final output is delivered back to our client in real time, and if it's in real time, we use the same protocol on our core side, helping our customers with the decision-making process," he said.

In one case study in Vietnam, Weatherford employed the reservoir monitoring system in an offshore well and installed 16 optical pressure/temperature gauges, replacing spotty electronic gauges and allowing the operator to manage the reservoir based on real-time pressure and temperature data.

With the installation, the operator was able to continuously monitor real-time downhole pressure and temperature. Throughout the three years the system has been in operation, the operator reported zero accidents or failure, according to the service company.

"You can deploy all fiber optics across the well and monitor the main completion downhole," Bello said. "In Weatherford, we have a series of instruments or global positioning units to collect data."

The data is transferred to a separate or real-time process unit, he said.

"You can deliver the output in real-time continuous monitoring and allocation [with] production optimization, automation control, in-flow profiling, production forecast and reservoir management," Bello added.

Weatherford's partnership with London-based data analytics company LYTT gives the company a better understanding of the data that comes from their fiber optics systems, with LYTT's Morrish comparing the data company to the engine of the operation.

Ratiba Bouzerna, alliances manager for LYTT, told Hart Energy the agreement is about providing Weatherford a layer of analytics regarding the position of data and acoustic temperature data through fiber, with data streamlined to LYTT's software to provide insight and actions about wealth, projection optimization in general, and hydraulic factory metering.

The hardware, with a design comparable to a smartphone, features applications focused on solving problems oil and gas producers might encounter in the field, such as production monitoring, well integrity and frac optimization.

"Arguably one of the biggest pain points within the fiber industry over the last 10 years has been the volume of data. A single unit of data would be the equivalent of streaming a thousand Netflix movies every hour for a full day," Morrish said. "It's an insane amount of data, and our IP [intellectual property] and our concept of that [hardware] really focuses on taking those obscene amounts of data and bringing them down to manageable sizes that insights can be delivered through."

With LYTT as the engine and Weatherford as the vessel, the partnership is able to provide continuous detection and arm the customer with the data required to make important wellsite decisions, Morrish continued.

Fracking future

Industry experts are predicting that the role of fiber optics monitoring in hydraulic fracturing digitalization will increase as it becomes more affordable. Although fiber optics already play an important role, its continued demand is likely to spur cost-innovative solutions so use can be more widespread.

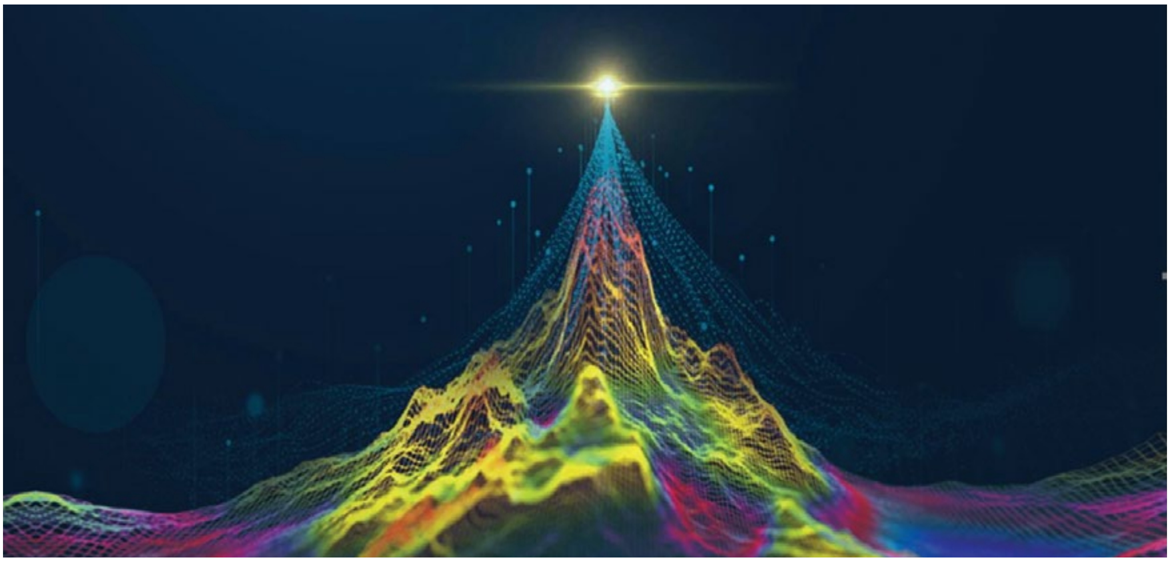
"Fiber optics are getting a lot cheaper," Stasiuk said. Deploying fiber optics "used to be around $1 million, and now it's a lot more affordable, and you're able to take it to scale."

Additionally, some of the remote features of hydraulic fracturing are expected to remain in place. Kari Bathe, senior marketing manager at ChampionX, told Hart Energy that with all the things that came with the pandemic, the ability to digitally operate helped pull the business sector through the dark times.

"I think the pandemic accelerated [the digital adoption process], and they gained enough trust and value in things like autonomous control where I don't think we're going to go backward," she said.

And even as restrictions are easing, Bathe said she expects continued momentum on that path.

"I think that in that regard, it sort of forced them to take that leap of faith, but now they've bought into that concept and have continued down that path," she said. OGI



WEATHERFORD

Weatherford's application allows users to manage, view and interact with terabytes of multidimensional sensor data in real time through a dashboard that leverages acoustic pattern-recognition technology and physics-driven modeling to extract and classify downhole events.

WELL SPACING

TECHNOLOGY ENHANCES UNDERSTANDING OF FDIs

Managing well spacing and frac-driven interactions improves efficiencies in unconventional plays.

ARTICLE BY
JUDY MURRAY
CONTRIBUTOR

Technology has been integral to shale development from the outset, streamlining operations, enhancing recovery and improving the bottom line. In lean times, when margins were slim, technology delivered efficiencies that enabled profits, and when prices recovered, technology allowed companies to maximize earnings. Learning from experience and applying best practices has led to changes in the way wells are completed and produced, and companies are continuing to experiment with development planning to capture maximum efficiencies.

Pre-pandemic, operators began using close well spacing to reduce expenditures. This approach seemed logical, but it yielded mixed results because of the effects of frac-driven interactions (FDIs), instances of interwell hydraulic communication that impact production. While Midcontinent acreage responded well to tightly spaced wells, close spacing in other plays proved detrimental to overall production. Contradictory results left operators trying to find a balance between well spacing and productivity, and that struggle continues today.

Well spacing and FDIs

According to industry FDI expert Ali Daneshy, the critical question for shale operators, both operationally and economically, is how to produce as much of the reservoir as possible at the lowest operational cost by drilling the least number of wells. That means an operator must determine the optimal well number and spacing and then optimize the fracturing treatment size to accommodate said spacing.

"The longer the fractures, the greater the spacing between wells can be," he said, explaining that FDIs provide the best information for determining the proper spacing of wells because calculations are based on data rather than guesswork or modeling. Since an underground formation is an "unknown," the best decisions can be reached only if the fracturing process is being monitored in real time, he explained.

"You are fracturing one well while you have adjacent wells that have already been fractured," Daneshy said. "As you're performing the fracturing treatment, you want to determine how the new fracture you're creating is interacting with the existing fractures in the formation. Based on the level of that interaction and properties of that interaction, you adjust the size of the treatment. If you're not doing this in real time, you are relying on a set pumping schedule that usually is too large."

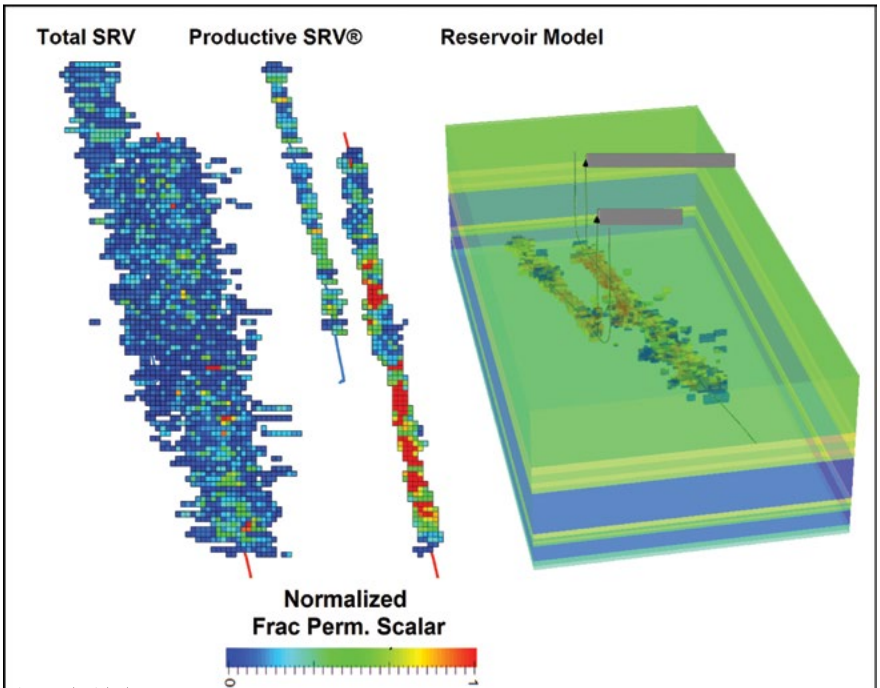
This is not only costly but can negatively impact production.

"Recording data from offset wells allows you to determine the level of interaction between fractures so you know how to adjust the fracture underway based on what is being observed," he said. "As you go through each stage and observe how the well is behaving, you can make adjustments to the pumping schedule for the next stage, taking advantage of the knowledge you just gained to optimize the next fracture."

There are multiple ways to carry out real-time monitoring, from recording and monitoring FDIs, to fluid tracing, to fiber-optic and microseismic arrays, he said, noting that the decision about which method to use depends on the budget and development plan.

Irrespective of the approach, real-time monitoring is critical, Daneshy said, because of the many interactions created between fractures that can influence decisions.

"If you manage a project in real time through real-time measurements, real-time analysis and real-time decisions, you reduce the risks of over- or under-stimulating the reservoir," he said.



Source: MicroSeismic

Well interactions observed during microseismic monitoring enable fracture permeability models to be created to rapidly evaluate the impact of child wells on parent wells.

Maximizing monitoring

Seismic monitoring during fracking is a tried-and-true method that continues to deliver value. Microseismic monitoring has been a part of shale development programs since 2005, but over the ensuing 17 years, the maturation of unconventional field development has led to a shift in the focus of microseismic monitoring. Today, the focus is less on reservoir monitoring and more on the interaction between primary and infill wells.

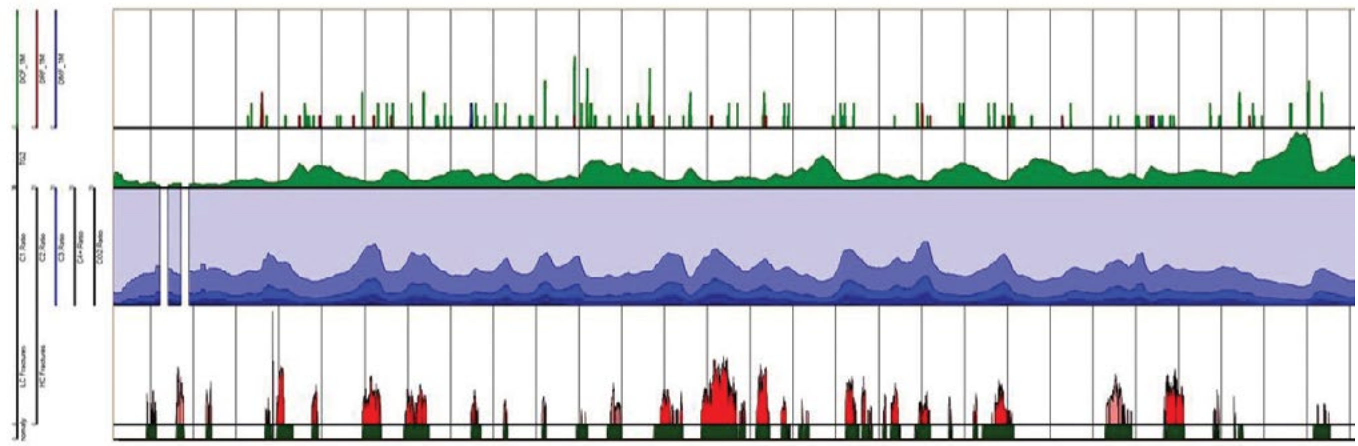
President, CEO and founder of MicroSeismic (MSI) Peter Duncan has witnessed this transition and has refocused his company's resources to deliver a real-time service. Duncan estimated that a year ago 50% of the work MSI did was driven by companies that wanted to monitor FDIs. Today, he said, "About 80% of the company's monitoring work in the U.S. is related to frac-driven interactions."

According to Duncan, operators have figured out how to frac well enough to meet expectations, but there is a huge drive to save money despite the current price of oil.

"There's been a sea shift in how business is being done," he said, and today, some clients are monitoring every well to mitigate the risk of adjacent wellbore damage during fracking.

What used to be a question of well spacing is now one of fracture management. Now, he said, well spacing is relatively fixed, and companies are focusing instead on pumping and monitoring to ensure fractures are not impacting nearby wells.

FDI-Influenced Depletion Analysis


Source: Drill2Frac

Findings indicate that where there is a depletion (bottom track), there often is a decrease in methane concentration (second to bottom) and a decrease in total gas (second from top). The location of the depletion coincides with fractures identified from a resistivity image log (top track).

"It is common now to see at least one or two instances of fault excitation that require pumping to be curtailed," Duncan said.

Because the arrays deployed by MSI are quick to pick up potential threats, it is possible to see excitation of a strike/slip fault in a matter of 10 to 15 minutes so pumping can be slowed to mitigate damage, he said. This can make a significant difference in well performance.

Duncan pointed to a recent frac job being executed from a three-well pad where MSI monitoring caused the operator to curtail or skip 30% of the stages. From this example, he said, it is clear that real-time monitoring is allowing operators to exercise greater control during the fracturing process to reduce FDIs and control the completion process for better overall project economics.

An alternative approach

While many of today's solutions require real-time data, Drill2Frac has introduced a unique way to derive insights after the well is drilled but before the well is completed.

Kevin Wutherich, the company's CTO, said his team began converting drilling data to rock properties about 10 years ago.

"We get information from the rig—the rate of penetration, RPM, torque on bit—and convert that into MSE [mechanical specific energy], which is a measurement of how much energy is being used," he said.

This technique has been used since the 1960s, Wutherich explained, noting that drillers used it to determine how effective the drilling process was and optimal drilling parameters. His team has adapted this approach to determine the compressive strength of rock, what Wutherich refers to as the RockMSE, by filtering out and normalizing the drilling effects.

For a shale development project, the team uses this data in a sort of "post-job lookback" that can be executed regardless of the age of the well. By analyzing RockMSE as well as other parameters obtained, "We can identify pre-existing fractures and mitigate fracture interactions caused by these features," Wutherich said.

He explained that there is a depletion halo around an existing fracture and that drilling an infill well across that depletion requires more energy.

"These preexisting fractures are a superhighway," he said. "If we were to place clusters at this preexisting frac, most of the induced energy is going to be wasted, dilating the existing frac and not breaking any new rock."

In one Delaware Basin study, multiple completion designs were evaluated in a single well, with one evaluation examining the effect of placing clusters in like rock while avoiding placing clusters in areas of localized depletion in the presence of FDI anomalies. The results of the diagnostics, which included microseismic monitoring and production tracers, showed that adverse fracture interaction with the parent well can be avoided by avoiding placing clusters away from the FDI anomalies.

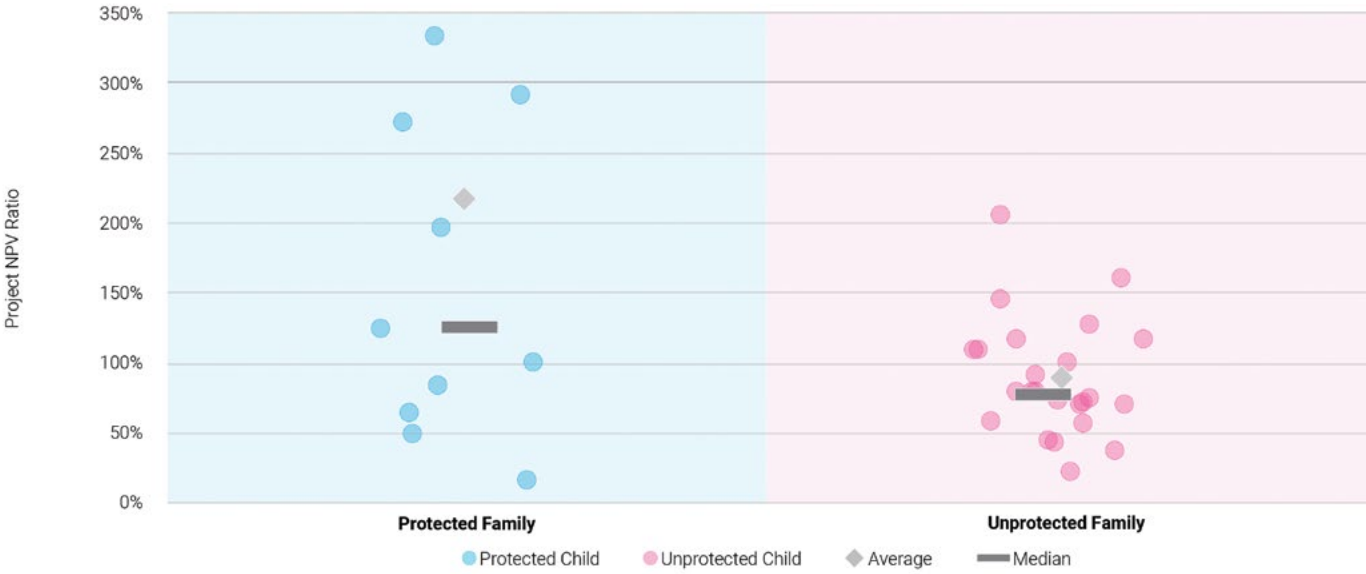
The insights Drill2Frac has gained from its efforts has led to some interesting observations.

"We've learned that most fracs are generally planar and can often extend for more than a mile," Wutherich said, noting that this contradicts common perceptions. "For a long time, there was a feeling that shale fracs were quite complex, but we are actually not seeing that in our work, at least in the far-field.

"Conceptually this depletion analysis is straightforward, but the actual interpretation is complex," Wutherich said. "Our process has proven to be 95% effective in the identification of localized depletion and validated through multiple diagnostics. Operators have been using this information to significantly mitigate, and in some cases eliminate, negative fracture interactions when completions are planned around the identified fractures."

Eagle Ford Shale well data show that a parent well "protected" by a refracture treatment generates approximately 50% higher family net present value ratio than the unprotected family at the median.

Family Well Economics



Note | Economics assume flat $55/bbl WTI and $2.75/Mcf HH. All economics are based on current capital assumptions.

Source: Enverus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Rethinking the economics

According to Enverus senior vice president of oilfield service intelligence Mark Chapman, the data from unconventional operations reveal insights that at times run counter to intuition. For one thing, he says, data gathered from shale players across the U.S. indicate well spacing in most cases is determined by reservoir quality and the operator's development philosophy rather than the characteristics of a specific well.

A more scientific approach to well spacing considers the implications of FDIs across a development and focuses on managing them for production optimization on a broader scale. With this evolution in thinking, Chapman said, operators have begun to consider the issue of well placement in terms of asset level economics rather than in simple terms of parent and child well interaction.

"In 2015 to 2016, most wells were parent wells with individual child wells being infilled," he said. "Now, new wells typically are co-drilled and co-completed. E&P companies are drilling the whole section at one time because that is the best thing you can do for the production and economics of all the wells. We are trying to design away the effects of FDI through pad or lease level economics."

To illustrate his point, he described a drilling trend in the Delaware Basin, where most operators are drilling the entire pad at one time. In some cases, he said, 10 wells might be drilled and completed from a single pad at the same time.

"There's still a parent well on either side that potentially could be impacted by an FDI, but we are eliminating that issue for all the wells in between," Chapman said.

But sometimes there are still parent-child considerations to account for. One strategy is to refracture parent wells to improve the performance of child wells.

"The idea is that if we can put energy into the parent well, it repressurizes the zone, and the child well's fractures can grow into untapped areas of the reservoir rather than into depleted areas," Chapman said.

The economics are calculated based on the production improvement across a family of wells rather than solely on the economics of the refractured parent well. An Eagle Ford Shale case study shows that a parent well "protected" by a refracture treatment generates approximately 50% higher family net present value ratio than the unprotected family at the median.

Another common practice is to repressurize a parent well. Although repressurizing a well has less dramatic results than refracturing, this approach often yields production gains at minimal expense, he said.

It is important to remember, Chapman said, "We're not just dealing with how to cope with well spacing and FDI. We are planning for the future and how to best develop our resources." OGI

NEW REALITIES CHANGE THE FACE OF FRAC WATER USE

Reusing produced water for frac jobs can improve production and ease the need for fresh water supplies, while also reducing demand for disposal wells.

ARTICLE BY
PAUL WISEMAN
CONTRIBUTOR

Since the advent of large-scale hydraulic fracturing in unconventional plays, the use of water in that process has been subject to study—and to change.

Producers searching for optimal combinations of sand and water to prop open tight shales have morphed from using clean water with hard, large mesh white sands from the upper Midwest to using very slightly treated produced water with locally obtained brown sand.

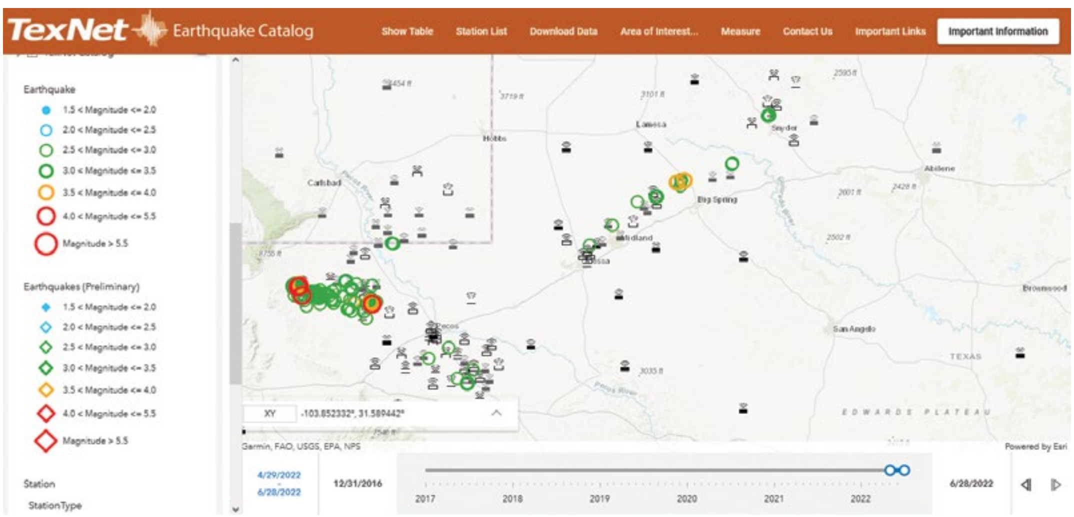
Water issues have come to the forefront as saltwater disposal wells (SWD) are associated with anthropogenic tremors as high as 4.5 in the Permian Basin (December 2021) and 5.8 in Oklahoma (September 2016), leading regulators to restrict SWD volumes in those and other areas. Additionally, concerns about the oil industry competing with agriculture and municipalities over diminishing freshwater reserves have pushed producers toward solving two problems at once by reusing produced water for fracking.

Currently there are no official figures showing how much produced water is being repurposed for fracturing but some have estimated figures around 10%, said Josh Adler, founder and CEO of Sourcenergy.

"Maybe that's as high as 20%," he said. Some individual producers may be recycling up to 50%, depending on issues with time, proximity and well design. However, he said, "There's not a way to definitively calculate that."

"It's been established for a number of years now that, if anything, using recycled water in fracs generates better results than using fresh water."

—Josh Adler,
Sourcenergy



In the 60 days covering April 29 to June 28, the TexNet Earthquake Catalog noted 150 temblors from 2.5 to 6.0 on the Richter scale. This is a narrow view of the larger state map, but the 150 events refer to Texas and bordering areas. It focuses on the areas of greatest seismic concentration during that time. The University of Texas Bureau of Economic Geology operates the catalog.

TEXNET EARTHQUAKE CATALOG

Any uptick in recycling water for frac use has several drivers, Adler said.

"One is environmental concerns about competing for groundwater with other, non-energy uses in a long-term demand growth environment," he said. "It's been established for a number of years now that, if anything, using recycled water in fracs generates better results than using fresh water" because water from the same formation is more compatible for the frac.

The nonprofit Groundwater Protection Council "is trying to incorporate [recycling figures] into their Frac Focus data more explicitly."

—Bridget Scanlon, *Bureau of Economic Geology, UT Austin*

Seismicity issues

During the past 10 years the importance, and relative cost, of completions has overtaken drilling in the industry, so water use decisions have also become more critical, Adler noted.

"The frac accounts for more than two-thirds of oilfield spending, while drilling is less than one-third," he said. "Ninety-six percent of new wells are horizontal," which require more and more water for the completion process.

Still, seismicity in the disposal process is a growing concern.

The nonprofit Groundwater Protection Council, an association of 17 states dedicated to monitoring and preserving groundwater quality, "is trying to incorporate [recycling figures] into their Frac Focus data more explicitly," said Bridget Scanlon, senior research scientist at the Bureau of Economic Geology, Jackson School of Geosciences, University of Texas at Austin. She noted that companies are sharing produced water through midstream companies in the Marcellus Shale, Permian Basin and elsewhere.

Katie Smye, co-principal investigator of the Center for Integrated Seismicity Research at the Bureau of Economic Geology, addressed the seismicity issue. She noted that the Permian Basin is responsible for most of the uptick in seismicity in Texas. Most earthquakes are associated with injection into two stratigraphic levels.

"In the Delaware Basin, earthquakes are associated with shallow disposal into the Delaware Mountain group, along with some associated with hydraulic fracturing as well. Those are mainly in the central and southern portion of the Delaware Basin," she said.

In the northern Delaware, indications are that the quakes are linked to deeper SWD activity, below the shale production zones. And in the Midland Basin, with SWDs

XRI HOLDINGS

XRI Holdings' onsite lab tests treated produced and recycled water.

One of about 40 XRI water exchange terminals the company operates in the Midland and Delaware basins.

XRI HOLDINGS

going into both shallow and deep zones, she said most seismic activity comes from disposal into the deep zones.

As a result, the Texas Railroad Commission has restricted SWDs in two areas, one near Stanton and the other near Gardendale, but activity has increased in Howard County as well, with 3.5 and 3.9 quakes recorded there in June.

Some operators in those areas have voluntarily reduced deep disposals, switching instead to either shallower wells or finding other ways to use water, including some recycling for fracturing, Smye noted.

ESG driver

XRI Holdings president and chief sustainability officer John Durand reported that his company treats and recycles approximately 1 MMbbl/d of produced water for reuse in hydraulic fracturing completions. That makes XRI by far the top produced water recycler in the Permian Basin, where Durand estimates that XRI is presently responsible for more than 50% of the water being recycled and reused across the Midland and Delaware basins.

XRI provides recycling and reuse solutions to its clients as an alternative to SWDs, particularly within seismically sensitive areas. The company reroutes produced water across the basin via large-diameter pipeline projects and provides full-cycle produced water management options, he said.

For frac water recycling gains, Durand agreed that ESG and sustainability metrics are among the drivers for their operator clients and for XRI. The company routinely provides clients with an ESG report card that operators use to gauge their progress in meeting ESG and sustainability targets.

As to how much produced/flowback water is being recycled for hydraulic fracturing, Durand joined Adler in bemoaning a lack of definitive data. Consensus estimates that number at around 7.5% in the Permian. The numbers that are available, said Durand, come from closely involved industry research companies and investment banks who follow XRI and their peers to aggregate, monitor and estimate such data.

As to the amount of produced water available in the Permian Basin, that number seems to be around 25 MMbbl/d of water—about 4.5 times the amount of current crude oil production over the entire basin. Some producers treat

"In the Delaware Basin, earthquakes are associated with shallow disposal into the Delaware Mountain group, along with some associated with hydraulic fracturing as well."

—Katie Smye,
Bureau of Economic Geology, UT Austin

and reuse produced water once, then dispose of the resulting produced and flowback water from that one-time reuse into disposal wells.

"For XRI and the majority of our customers, use of disposal as a last resort only has relevant and meaningful benefits when it comes to ESG and sustainability measurables," Durand said.

"The industry is refocusing by moving to recycling and reuse and relying less on groundwater sources."

—John Durand,
XRI Holdings

He said the industry is refocusing by moving to recycling and reuse and relying less on groundwater sources.

"Not long ago, operators were touting aggressive goals to eliminate the use of fresh water for completion water," he said. "Now, you are seeing those same companies focusing on produced water recycling and reuse as a predominant source of completion water."

The majors are going to lead the way, he said, though private equity-backed independents are also embracing recycle and reuse.

"When you see where the flow of investment dollars has gone over the last couple of years from private equity groups and the institutional investors, that means everybody who's drilling in the Permian or anywhere else has to factor in the benefits and importance of developing and tracking ESG goals and achievements year-over-year," he said.

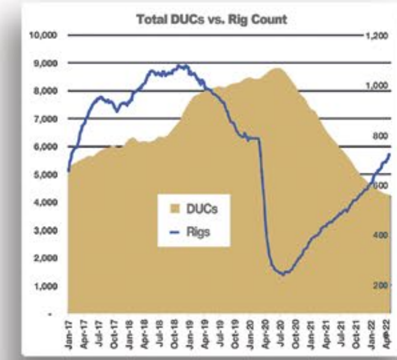
Durand said the "sweet spot" for frac completion water use is about 600,000 bbl per well, although some companies use more depending on the number of frac stages. This number has changed little since 2020.

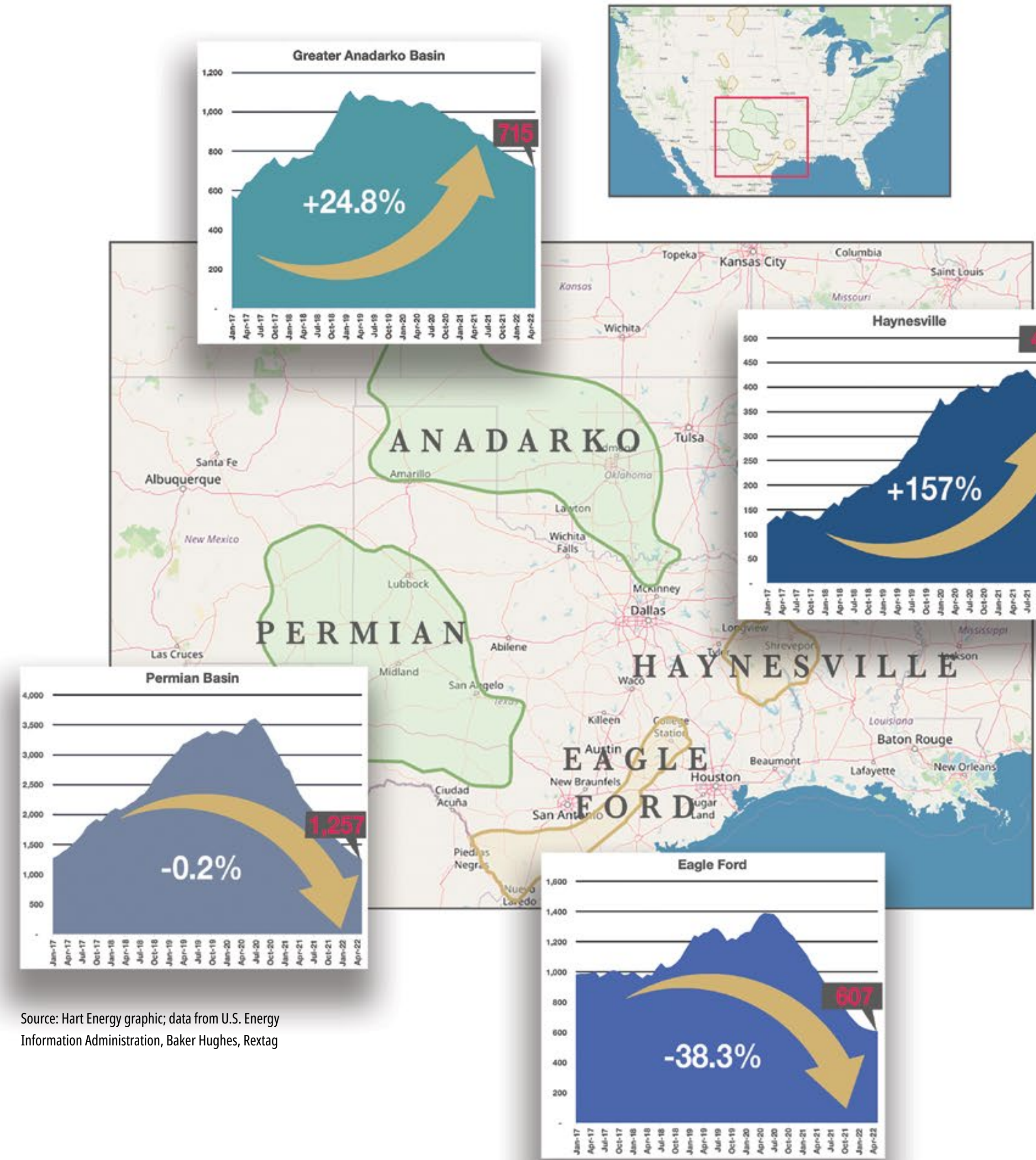
XRI expects produced water recycling percentages to rise steeply to approximately five times the current 7.5% in the Permian, equating to approximately 40% recycling rates by 2025, he said. XRI alone is looking to recycle 1.1 MMbbl/d at current growth rates.

It is clear that the combination of rising frac costs with seismicity concerns is forcing operators to re-evaluate water use from frac to flowback to production. OGI

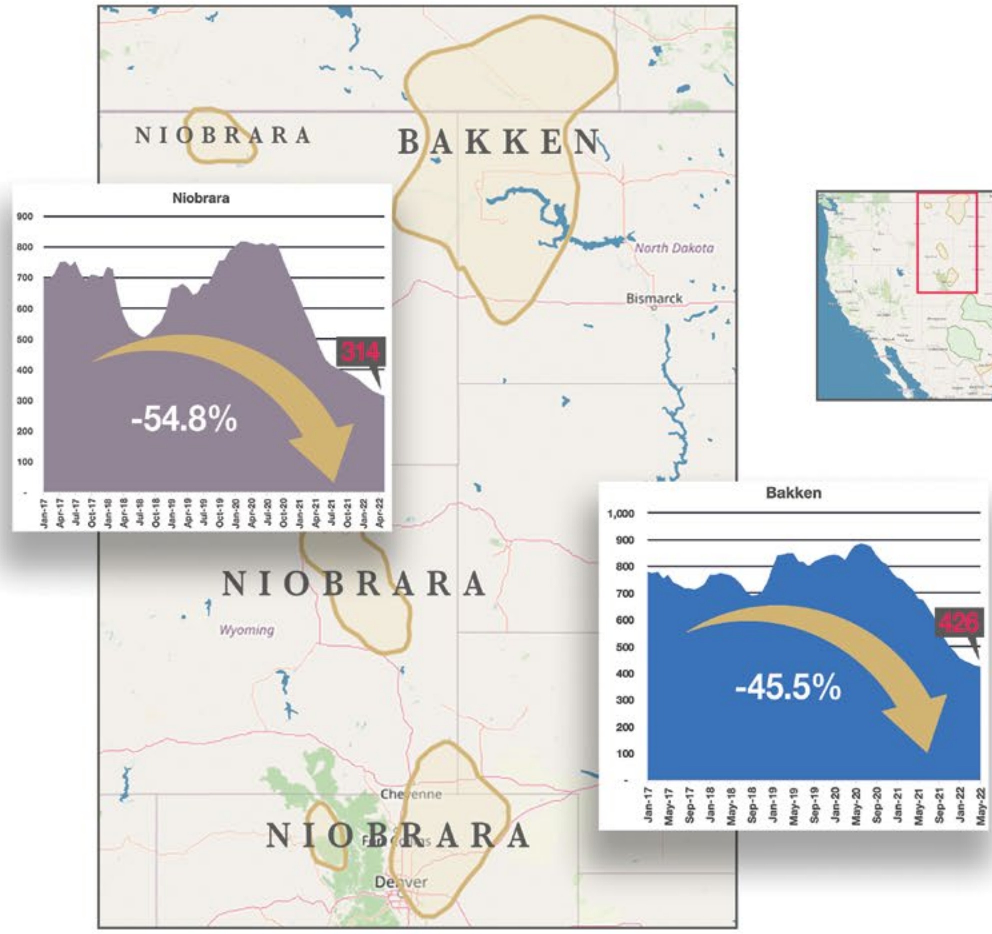
DUCS' FIVE-YEAR TRENDS

As the number of drilling rigs operating in North America has gone up, the number of DUCs has gone down. The DUC count has declined in all but two of the major plays over the past five years, in most cases by a significant amount. Producers drew down their large DUC inventory to increase production. Without that drawdown of DUCs, Mark Finley of Rice University's Baker Institute for Public Policy estimates that producers would have needed an additional 100 rigs to generate that output.





Source: Hart Energy graphic; data from U.S. Energy Information Administration, Baker Hughes, Rextag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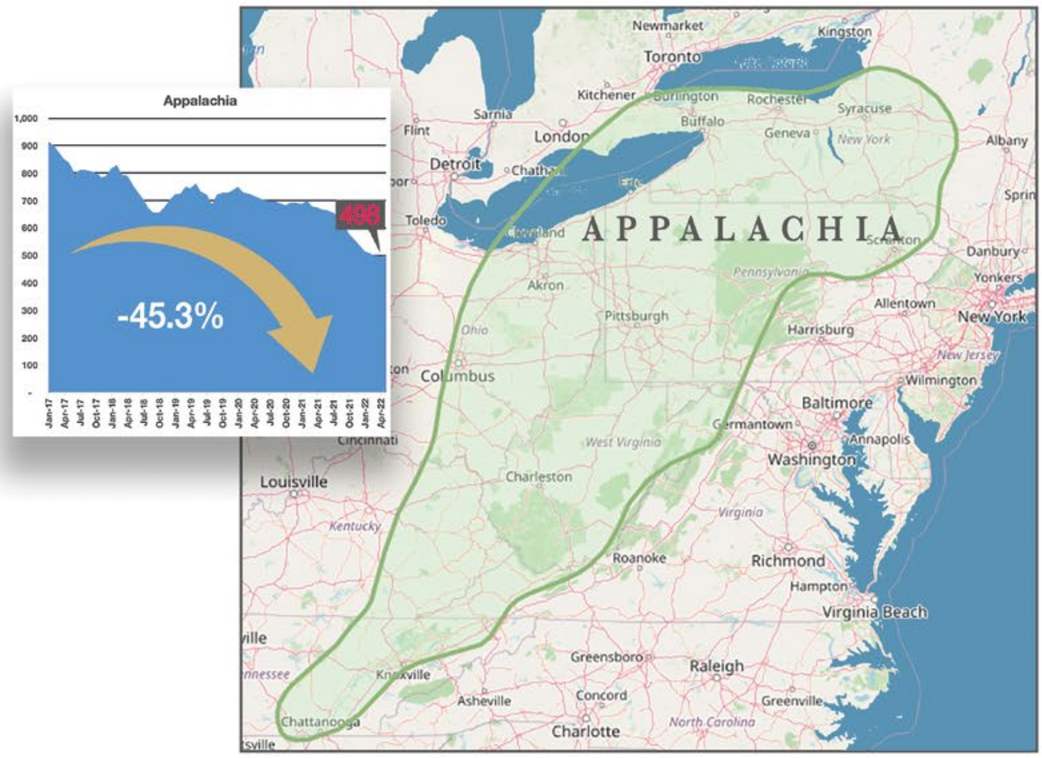
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Asheville
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Chattanooga
Charlotte
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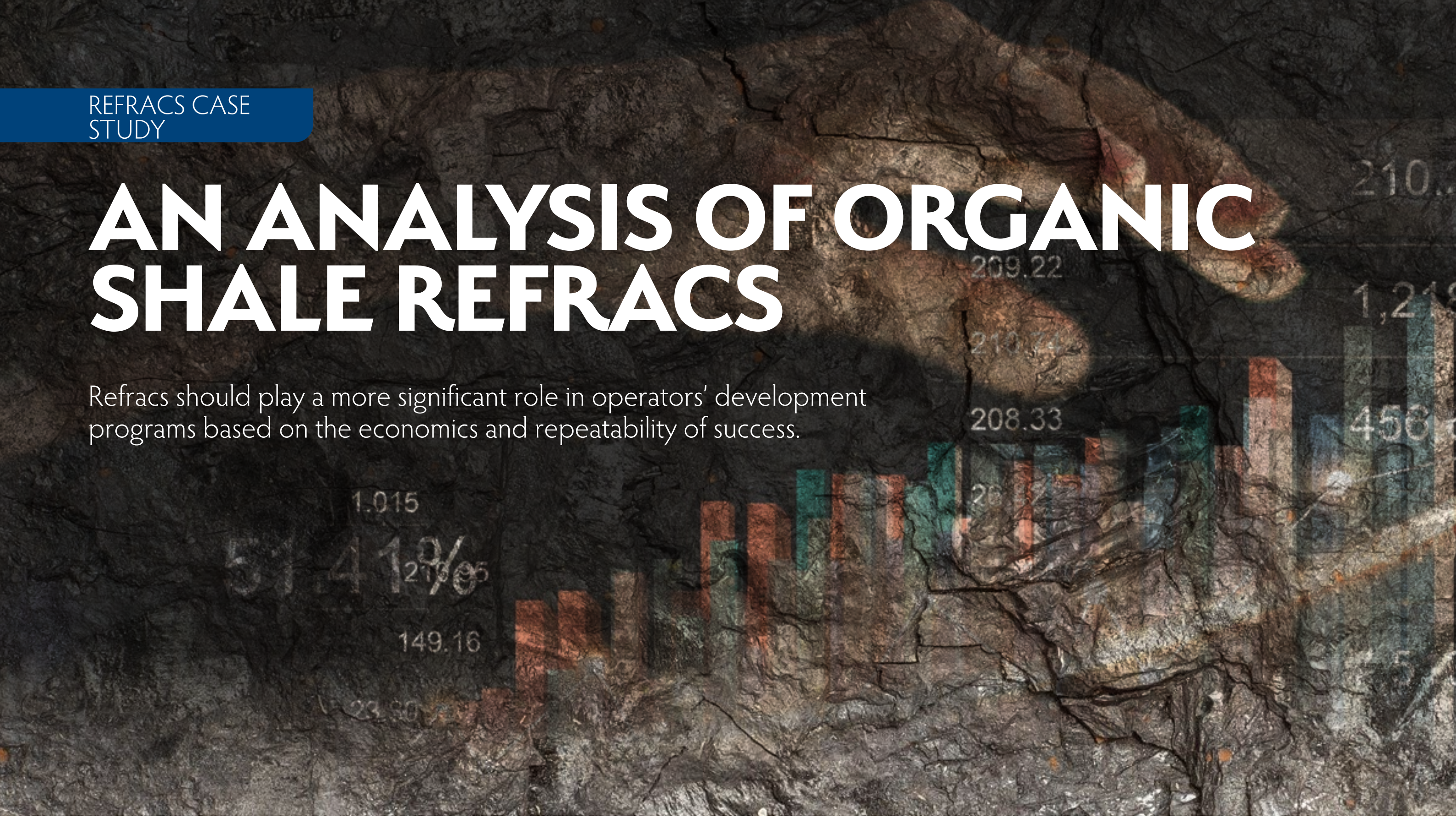
AN ANALYSIS OF ORGANIC SHALE REFRACS

Refracs should play a more significant role in operators' development programs based on the economics and repeatability of success.



ARTICLE BY
BOB BARBA
INTEGRATED ENERGY SERVICES

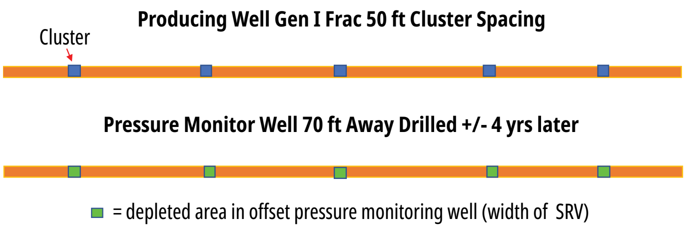
Operators have been on a steep learning curve with organic shale frac treatments since the first Barnett Shale horizontal multistage fracs in the early 2000s. It was known early on that it takes 100 days for a gas molecule to travel 1 meter in 100 nanodarcy rock, thus organic shales have close to zero permeability unless the rock is stimulated with a frac treatment.

Nonetheless, it took until 2015 through 2016 for the majority of operators to implement close cluster spacings in organic shales to get the maximum stimulated rock volume where close to 100% of the flow is coming from in the system versus the relatively impermeable rock matrix. Unless perforation clusters are placed relatively close together and cluster efficiencies are high, there can be a significant amount of stranded hydrocarbons.

Eagle Ford and Permian case study

In one Eagle Ford pilot test done by ConocoPhillips Co. with a pressure monitoring well 70 ft from the fracked well, it was observed that only 7.5 ft of lateral drainage was occurring at each cluster (Figure 1).

Figure 1: Eagle Ford Refrac Case Study



This image depicts the results of a ConocoPhillips pilot test well conducted along with a pressure monitoring well.

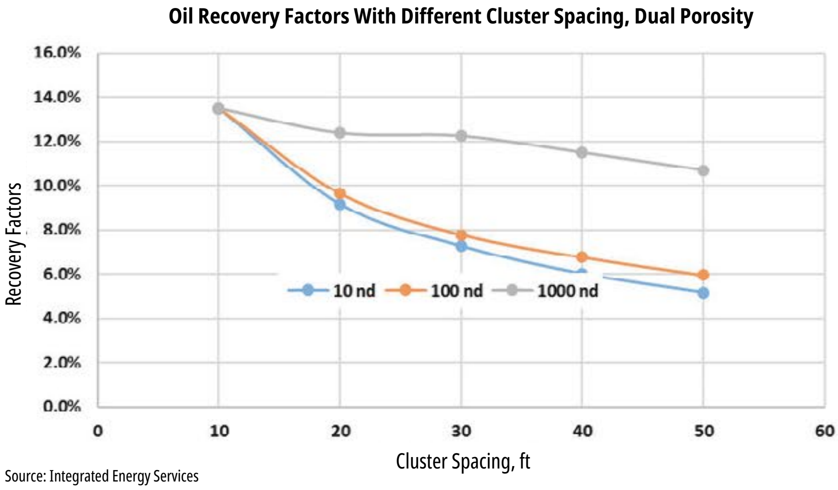
Source: Integrated Energy Services

This shows that 85% of the rock was not being drained with the 50-ft cluster spacing. The 15% of the total rock volume that was physically drained correlates to a 2.25% recovery factor, which is in the range that is frequently observed with cluster spacings of 50 ft or greater. There is a strong correlation between cluster spacing and recovery factors in organic shales (Figure 2).

Fifty-foot cluster spacings or higher without diversion in the Eagle Ford oil window and Permian Wolfcamp have maximum recovery factors of 3.5% based on the simulations in the study that were validated in SPE URTeC 2662. As noted, the ConocoPhillips study in the Eagle Ford had recoveries in line with the University Lands study that was conducted in the Permian Wolfcamp. The main unknown in estimating recovery factors from cluster spacing is the cluster efficiency, or what percentage of the cluster count is producing hydrocarbons.

All the simulations that were done in the University Lands study assumed 100% cluster efficiency. Therefore, if this efficiency is lower than 100%, the recovery factors should fall below the curve from these simulations. With the field validation of the cluster spacing to recovery factor relationship, it is possible to estimate a minimum recoverable oil volume for a refrac by dividing the cumulative production by the recovery factor that corresponds to the measured

Figure 2: Recovery Factor Vs. Cluster Spacing



Source: Integrated Energy Services

cluster spacing to get an estimate of the minimum oil in place (OIP).

The difference between the expected recovery of 13% to 14% of this OIP value and the cumulative production is the minimum expected recovery from a refrac. Since the majority of pre-2018 wells did not have adequate diversion, the effective cluster spacings were significantly larger than the physical separation, and the OIP estimate should be conservative for undiverted completions and relatively close for high cluster efficiency fracs.

In 2018, operators began to implement extreme limited entry (XLE) where 2,500 psi to 3,000 psi pressure drops across the perforations were applied and 80% to 100% cluster efficiencies have been documented. Once XLE became accepted, cluster efficiencies increased significantly from around 60% to over 90% in most cases. Prior to XLE, operators either did not use any diversion techniques or they relied on physical diversion material such as ball sealers, polylactic acid or fiber "pods" to control leakoff into the more permeable depleted clusters in refracked wellbores.

These methods have had mixed success, with one recent study showing seven new wells that used pod diversion having an average recovery factor of 7.4% versus the 13% to 14% range expected with high cluster efficiency. In that same study, it was shown that five refracs had a 13.2% average recovery factor in the same field as the seven new wells. This was attributed to refrac reorientation from pore pressure depletion in the maximum horizontal stress direction that caused a reversal of the frac direction that resulted in a significant increase in the stimulated rock volume along the wellbore and total recoveries equivalent to a close cluster spacing XLE treatment.

In the Eagle Ford, the average cluster spacing did not drop below 50 ft until the second half of 2016 after more than 15,000 wells had been completed with recovery factors approximately 10% lower than they would be with close cluster spacings (12 ft to 15 ft typically). The largest operator in the Permian did not go below 60-ft spacing until October 2015. There are more than 4,500 wells in the Permian Wolfcamp and 3,000 wells in the Haynesville Shale with wide cluster spacings, and most have less than 25% of the total EURs that are possible with close cluster spacing XLE completions in all areas. Total EUR is the cumulative production before the refrac plus the EUR for the post-refrac period.

The opportunity of refracs

In every challenge there is opportunity, and this is not an exception. Refracs can economically access these stranded hydrocarbons, and studies indicate that most of the legacy wide cluster spacing completions are refrac candidates. Operators have come to realize that if fluid loss can be controlled into the regions around the depleted clusters with XLE that new rock can be accessed to result in total recovery factors (cumulative production prior to the refrac plus the refrac EUR) approaching 13% to 14% in the Eagle Ford and Permian oil windows and 35% to 40% of the gas in place for the Eagle Ford condensate window.

With that knowledge, an accurate appraisal of the remaining recoverable oil and gas can be made by subtracting the current cumulative production from the total number.

Competing economics

A commonly heard observation is that refracs cannot compete with new well economics, and in areas with top quality Tier 1 opportunities, this might be the case. That is not the case, however, for the average Eagle Ford well, and there is a finite number of top-quality Tier 1 candidates available. One recent Eagle Ford study showed that the P50 net present value (NPV) for a liner refrac in the Eagle Ford at October 2021 prices is $5.9 million with an IRR of 80% (Figure 3).

With the current price strip, these NPV values are over 150% higher than the more conservative October 2021 deck. This is just the value from actual refrac declines at the well level, assuming current completion costs. There are additional benefits at the pad level as well that can essentially double the NPV when primary parent wells are refracked in a zipper, or simulfrac, completion on a pad.

Refracking a primary parent well builds a "pressure wall" that restricts the infill child well frac from migrating toward the depleted parent well clusters with an asymmetric frac. These asymmetric fracs have been shown to reduce the EUR in the first order infill wells by 40% or more since stimulation of the distal side of the infill well essentially stops once the frac on the proximal side encounters the depleted area around the parent well. If new wells in the area are in the 500,000-bbl

EUR range, the NPV saving from the primary well refrac protection feature is $4.5 million at the October price deck. When the NPV from the refracked well and the infill protection NPV are combined, the refrac has a $2.9 million higher NPV than a new 500,000-bbl EUR well in the Eagle Ford oil window.

A subsequent study in the Permian Wolfcamp suggested that similar total NPVs for the refrac production plus the child asymmetry mitigation were higher than new well NPVs in wells with 60-ft cluster spacing and 88% of the new well NPVs in 40-ft cluster completions. The Haynesville was an exception to that trend, most likely as a result of poor cluster efficiencies due to the high friction losses in the 3.5-inch cemented liners. The combined NPV from production plus the child damage mitigation was around 50% of the new well NPV for a P50 EUR in the play. These results should improve when operators start using expandable liners that can provide a 3.25-inch inside diameter (ID) inside of 5-inch casing versus a 2.75-inch ID for the more commonly used cemented liners. When the casing is 5.5 inches, the expandables provide a 4.1-inch ID versus a 3.4-inch ID for cemented 4-inch flush joint. The larger diameter tubulars have much lower treating pressures, and in the liners run in 5.5-inch casing, the larger diameter perforating charges can be run that have been shown to reduce near wellbore friction and erode less than the smaller diameter holes to maintain diversion with XLE.

Minimizing risks

Another commonly heard objection to refracs is that they are mechanically more complicated than new well completions and that there is a higher risk of failure. Prior to the adoption of mechanical diversion as the preferred isolation method for the existing perforations, results were mixed when operators pumped bullhead treatments with diversion material. Bullhead diverter treatments were found to be ineffective in treating more than 2,000 ft of lateral at a time, and the majority of the refracked wells had 4,500- to 5,000-ft lateral lengths. Within the 2,000-ft length, the tracers were consistently showing a strong heel bias, and the sections toward the toe had decreasing tracer concentrations. XLE is not possible in bullhead treatments due to the large number of open perforations (often 800 to 1,000 in a 5,000-ft lateral).

While bullhead diverter treatments do not maximize production from the laterals, the cost is significantly less than liner refracs. A $1.5 million authorization for expenditure (AFE) was assumed for the 45 single well lease bullhead treatments, and only one of the 45 treatments had a negative NPV10.

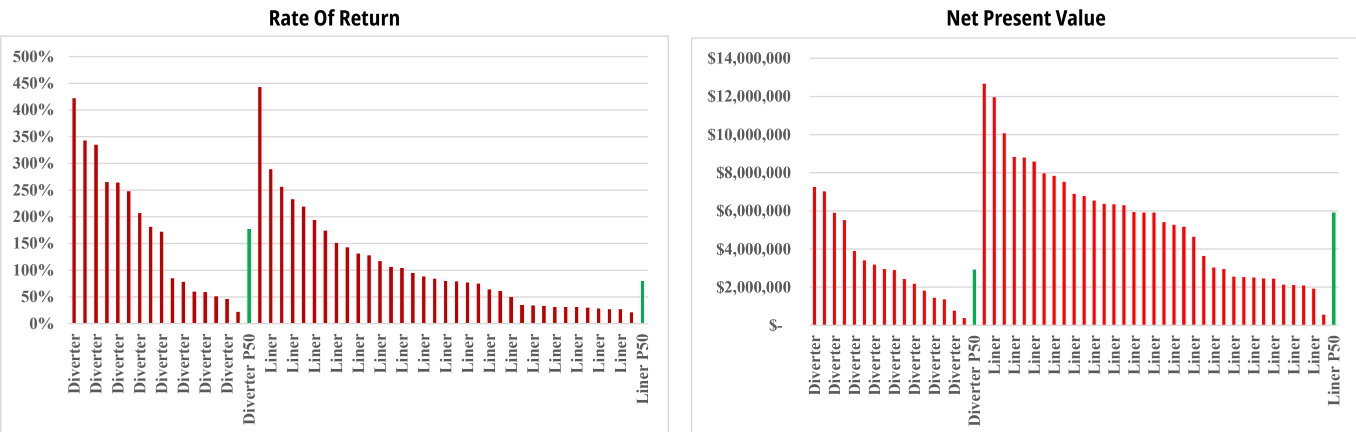
With the advent of mechanical diversion, using either an expandable liner or cemented smaller diameter casing, the cluster efficiency increased significantly over the bullhead diverter jobs.

In SPE 3724057, an Eagle Ford example was cited where the original 50-ft cluster spacing in June 2014 completion had a 2.9% recovery factor prior to the first bullhead refrac treatment. A bullhead diverter treatment was pumped in July 2016, and the total recovery factor (cumulative oil prior to the refrac plus the post-refrac EUR) increased to 3.8%. A liner refrac was conducted in December 2017, and the total recovery factor increased to 12.9%. Liner refracs had consistently higher production than bullheads, and if a $4 million AFE is assumed, all 34 of the single well lease liner refracs had a positive NPV10. All the economics were run with the October 2021 price strip and should thus be conservative with respect to the current pricing.

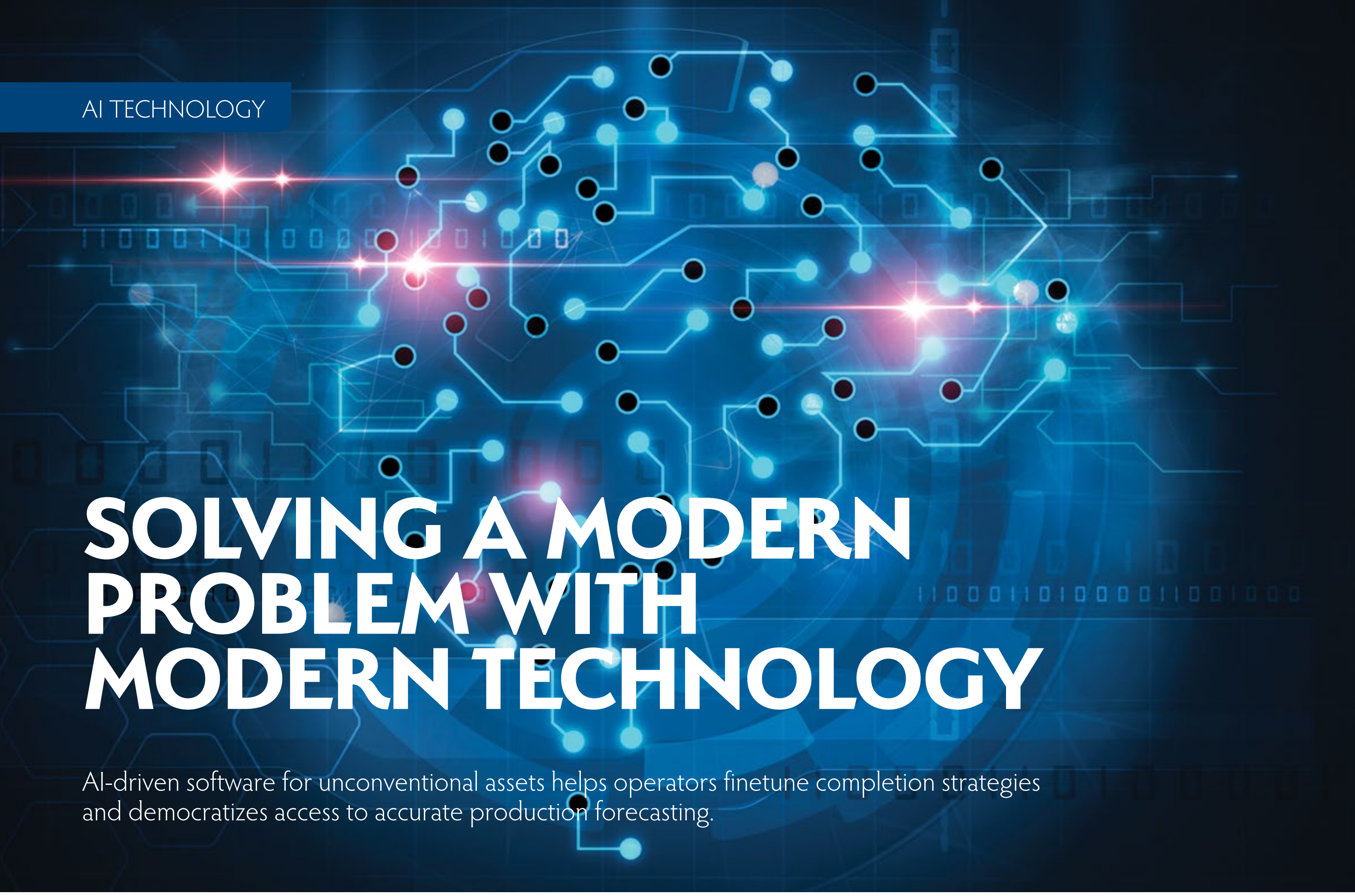
Based on these actual refrac results, operators can have a high degree of confidence in the probability of success for refracs. The stigma that refracs are risky and not competitive with new well investments is not supported with the production numbers that are the result of actual refracs. Refracs should play a more significant role in operator's development programs based solely on the economics and repeatability of success. By combining the features and benefits of fewer moving parts in a challenging supply chain system, as well as a lower carbon footprint, the scale should finally tip in favor of refracs when they are competing with new wells for capital. OGI

References available upon request.

Figure 3: Eagle Ford Production Economics Distribution



Source: Integrated Energy Services



SOLVING A MODERN PROBLEM WITH MODERN TECHNOLOGY

AI-driven software for unconventional assets helps operators finetune completion strategies and democratizes access to accurate production forecasting.

ARTICLE BY
JENNIFER PALLANICH
SENIOR EDITOR

Forecasting production for unconventional wells needs a modern approach that is able to deal with the complexities of shale reservoirs, rather than old-school models devised for vertical wells.

Artificial intelligence (AI) and cloud-native software is helping "gamify" production forecasting and enabling operators to refine their completion and production optimization plans and identify upside potential for assets in U.S. shale basins. The AI software for unconventional assets, developed by AlphaX Decision Sciences, decreases modeling and decision-making time, according to the company.

What has historically been done in production forecasting is taking "a set of equations developed in the mid-1940s and just slapping a user interface on the top of it," said Ben Zapp, completions engineering manager at Lario Oil & Gas.

J.J. Arps was a geologist who described well production declines in conventional vertical wells in 1945, and his mathematical models are still in use for that purpose, today.

The problem is, this approach has worked for conventional and vertical wells but doesn't translate well into how shale reservoirs and lateral wells work, Zapp said.

"We have built the understanding of the subsurface in multi-dimensional space to comprehend and solve for the complexity of the geology and shale reservoir's interdependencies."

—Sammy Haroon,
AlphaX Decision Sciences

Up until a few years ago, Lario was faced with the challenge of how to expediently figure out the best way to test and check production forecasts resulting from variations in completion design and spacing. The reservoir engineers did their best to forecast based on statistics and histories, he said, but it wasn't sustainable or objective. It took time, and results could vary.

"It was only as accurate as the humans that were doing it and the attention they put into it," Zapp said. "These are people. We don't have unlimited cognitive capacity."

In addition, he said, biases can get rolled into production forecasting.

"You can put 100 reservoir engineers on a project and get 90, 95 different answers for what they think each forecast will be," he said.

"With Sky, we can perform rapid sensitivity analysis between these variables to produce the optimal asset development strategy for our company."

—Ben Zapp,
Lario Oil & Gas Co.

Hear more from Ben Zapp of Lario Oil & Gas in an exclusive video interview at HartEnergy.com.

AI technology

By bringing AlphaX's Sky, the AI-based and shale-savvy software, into the completion planning and production forecasting processes, Lario has been able to refine production optimization plans based on checking how changing different variables alters the production forecast, Zapp said.

An example of this, he said, is trying to answer the questions around the optimal spacing between wells, the optimal development methodology and the optimal completion size.

"With Sky, we can perform rapid sensitivity analysis between these variables to produce the optimal asset development strategy for our company. This analysis has yielded well performance enhancements greater than 10% of the P50 for our basin peers. This has real value, as our drillable inventory is currently in the hundreds of wells," he said.

Sky is "heavily gamified" and intuitive, Zapp said, allowing him to "slice and dice" data sets.

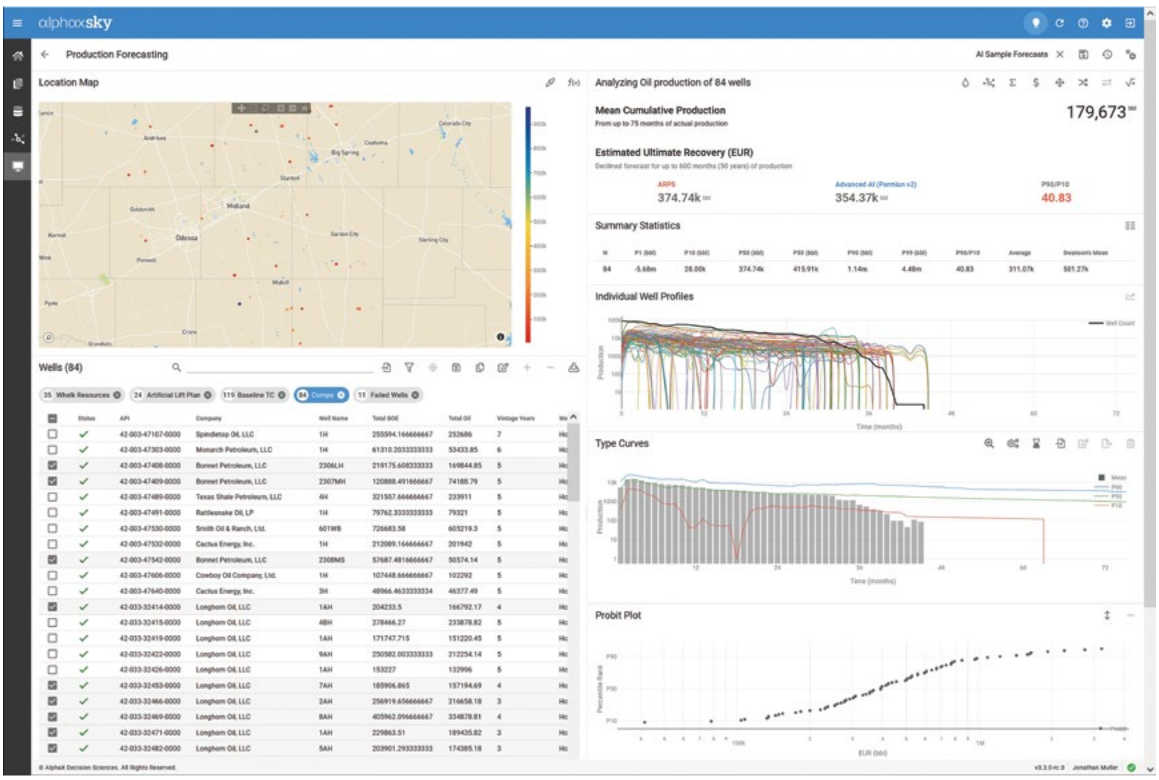
He can see how the forecast changes based on spacing between certain wells, for example.

"It will give the arc for two different AI results," he said.

One arc is for the next 12 months, which helps inform cash flow expectations, and the other predicts further out, which is useful, for example, for artificial lift conversion timing, he said.

And as such, it's possible for Lario to forecast with AI what the 7,000-plus wells in the company's inventory will do in different circumstances, he said.

"The oil field is coming around to artificial intelligence and machine learning and higher computational power that the rest of the world gets to enjoy," Zapp said.



ALPHAX DECISION SCIENCES

AlphaX Sky's basin-specific models create real-time, data-driven AI forecasts for individual well volumes and type curves.

Hydraulic fracturing underway at a Lario Oil & Gas field in the Midland Basin.

LARIO OIL & GAS

Using Sky, Lario was able to take their internal data sets, including proprietary and public data for over 7,000 wells in the basin, to determine the best way to complete them by plugging in variables and current best practices and then integrating the results into the company's budgeting and asset development model, he said.

Lario has also done some history matching to assess the accuracy of the Sky forecast, he said. The accuracy has been within single digits on the wells over quarter-to-quarter checks, he said.

"It's completely reasonable, especially given how dynamic things are and how much things move in that amount of time," Zapp said.

And more recently, Lario has also used Sky to forecast upside potential for assets, using not just core targets but targets at other depths, he said.

"The use of this product has meant that we can run our workflow through the machine and trust it and get on with what we're doing," Zapp said. "This is a solution to a modern problem that's been derived in the last five years, not the last 50."

Sammy Haroon, founder and CEO at AlphaX Decision Sciences, said it just didn't make sense to try to use a mid-20th century solution for vertical wells like Arps models to solve the 21st century problem of unconventional lateral wells.

"Arps is trying to replicate nature but with such minimal information" because it was developed at a time when computing was slow and expensive, and data was sparse and expensive to process, Haroon said. And "trying to twist and turn" Arps models to fit unconventional wells will lead to errors.

Part of the problem is that the industry "doesn't really understand subsurface physics" of the shale reservoirs, he said.

"We comprehend the behavior of the subsurface based on how we are interacting with it" such as fracking, pumping fluid or perforating it, Haroon said, having observed the problem initially while managing Baker Hughes's Enterprise Data Analytics group. "We have built the understanding of the subsurface in multidimensional space to comprehend and solve for the complexity of the geology and shale reservoir's interdependencies," he said.

What was needed is not just a multidimensional understanding of the subsurface but multidimensional mathematics, he said. And while the math can be done, it is too complicated for humans to cope with because of the sheer number of dimensions and variables involved, he said.

Enter AI, enabled by 21st century advances in computing power and data connectivity.

"AI must do two things, otherwise, it's of no use," Haroon said. "It should exponentially decrease the time to decision making and

"AI is not telling you what decision to make. It gives you the unbiased evaluation."

—Aruna Viswanathan,
AlphaX Decision Sciences

significantly increase the accuracy of the decision enabling a direct and measurable economic impact. This is now possible because algorithms which were computationally infeasible 20 or more years ago are now easily implemented even on mobile devices, making practical use of all the available data to rapidly make the best decisions possible."

Removing bias

AlphaX COO Aruna Viswanathan said AI offers another benefit in that it removes bias from decision making.

"The evaluation of anything is biased to whatever data you have available or that you may be given or choose to go get. Your own mind can only process so much," she said. AI is "not telling you what decision to make. It gives you an unbiased evaluation."

Viswanathan said Sky helps value oil and gas assets.

"An oil and gas well is an asset that is declining in value every day, every week, every month, every quarter, every year," she said. And as such, "timely decisions affect the value of the asset, especially early in the asset's life when you have the least information."

Sky's interface makes it easy for every stakeholder in the decision-making process to understand a forecast, she said.

"Reservoir and production engineers, geologists, even financial analysts can all see the same thing and see the same answer," she said. "This collapses the entire workflow, brings everybody onto the same page. It democratizes the information."

The AI-driven Sky software helps operators better understand well depletion over time with faster and more accurate production forecasting, Haroon said.

"Our approach is pure mathematics overlaid with subject matter expertise," Haroon said.

Sky has basin-specific AI models that use public data from a number of sources, including Hart Energy's RexTag, he said, and customers can add their own data, such as pressure information or daily production, into the system to test or even further tune the models. Currently, Sky has models for the Permian, Eagle Ford, Haynesville, Williston and Bakken basins.

"It understands the complete basin behavior within the model, and it uses everything it knows about the well," Haroon said. "It understands geology, the reservoir, drilling [and] completion."

Sky also doesn't remove outlier data from the models the way statistics does, he added.

"Interactions with the subsurface and its responses is still information," Haroon said.

Haroon said reservoir engineers are using Sky to quickly project how much a well will produce over a period of time.

LARIO OIL & GAS

A rig at a Lario Oil & Gas field in the Midland Basin.

"It helps them look at the influence of parameters of a well in ways they were not able to do before," he said. "They can now quantify, for example, based on how the well was completed, how it impacts production."

Completion and production engineers can use Sky to see how the company's wells compare to competitors, he said. It can help them answer questions such as, "Why am I not doing as well as my competitors? What is the completion style I should be using?" along with making decisions on their artificial lift strategies.

"For the engineer, what starts to happen is you don't work with the past. You start looking into the future," Haroon said. OGI