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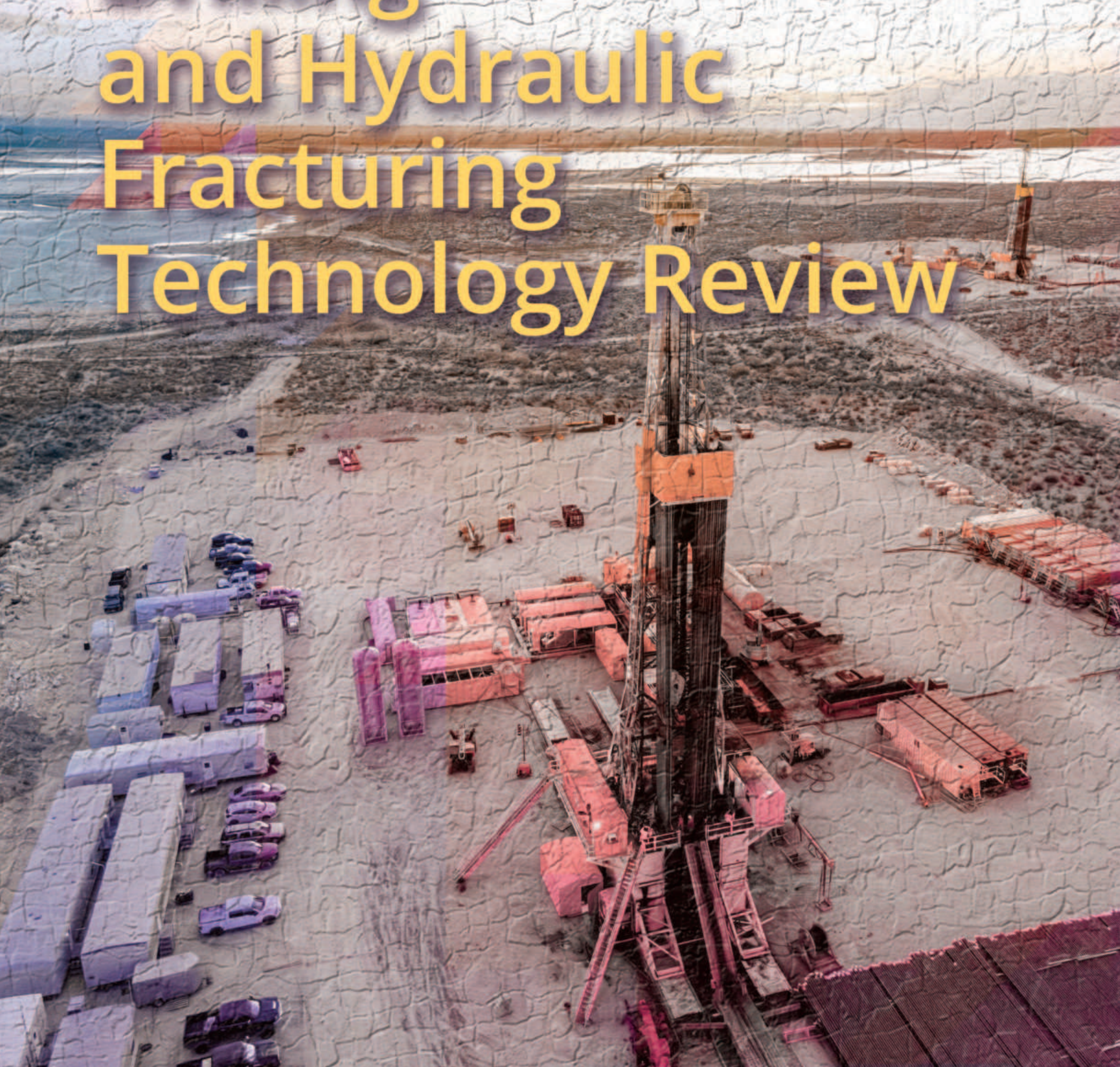

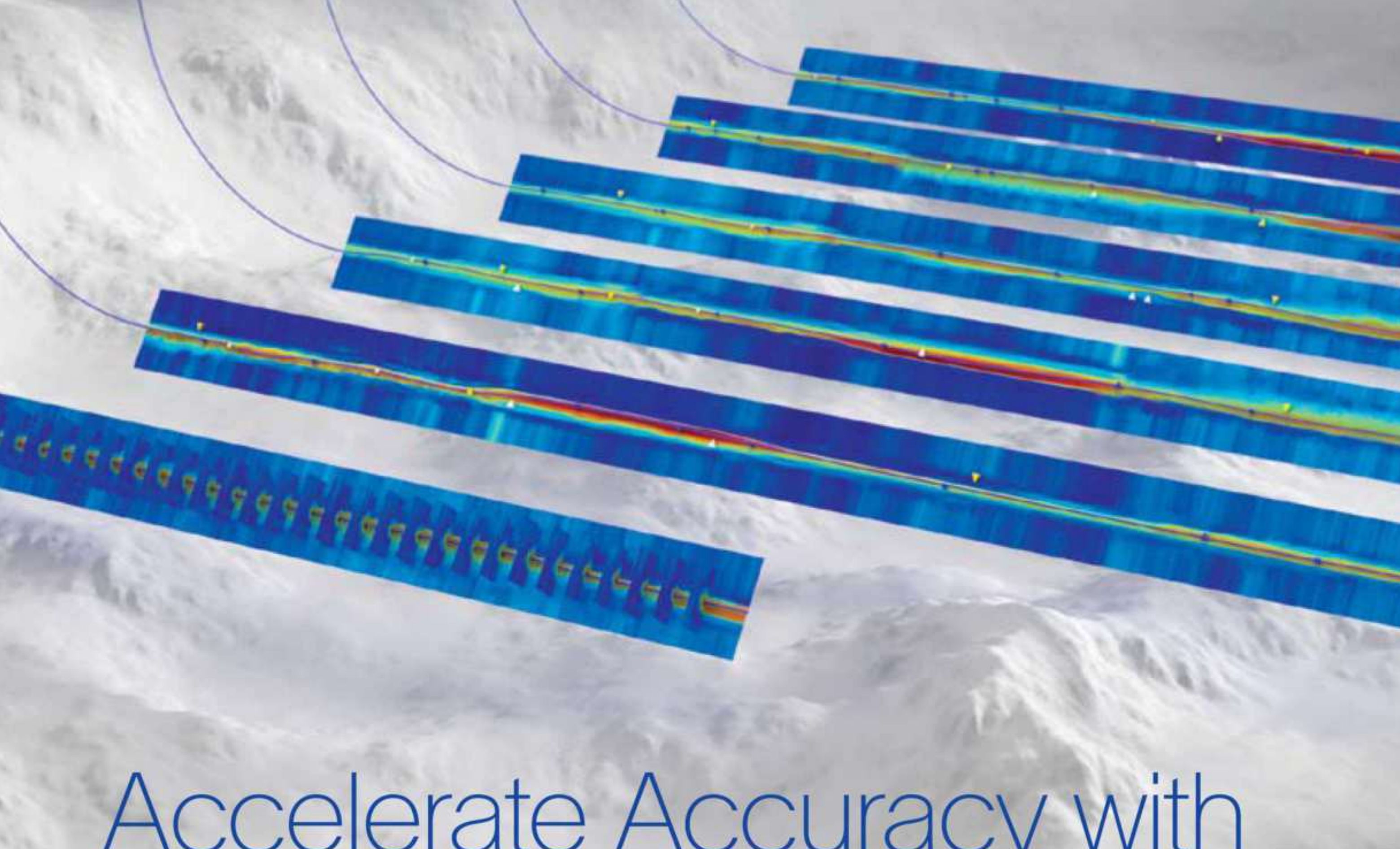

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On the cover: Sunset over the Permian Basin. *Source: Grand River/Getty Images.*

An Official Publication of the Society of Petroleum Engineers.

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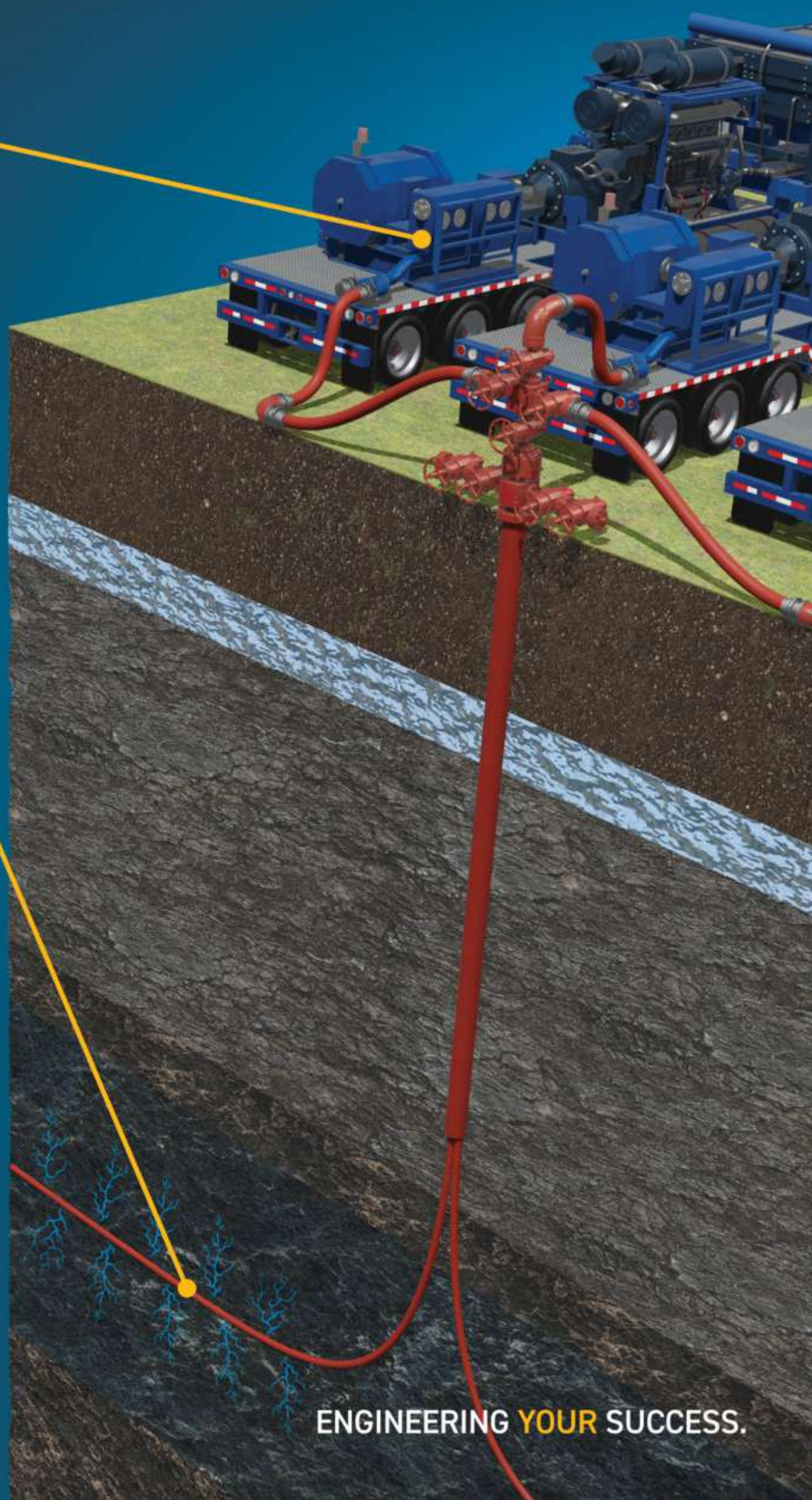


Parker

ENGINEERING YOUR SUCCESS.

Shaping the Future: Ingenuity and Clever Efficiencies Drive Drilling and Completions Forward

Trent Jacobs, Managing Editor

In this special publication from *JPT*, our editors have curated a selection of recent articles and guest contributions to highlight the advancements made by the drilling and completions sector.

They show how innovative concepts, such as horseshoe wells, have evolved from obscure experiments into forward-thinking strategies for reducing the cost of unconventional development.

They remind us that ingenuity and innovation doesn't have to come from a new tool or by partnering with a big software company.

Sometimes it just takes working smarter than before, such as piling fracturing sand on location instead of storing it in rental containers which reduces pad traffic while saving hundreds of thousands of dollars per well.

A few years ago, we saw shale ingenuity take the form of the "simulfrac" method which enabled operators to hydraulically fracture two wells simultaneously. Today, operators are taking the clever efficiency gain a step further with the adoption of "trimulfrac" techniques that for some have delivered cost savings exceeding $1 million per well.

In the drilling arena, we have seen such major strides in the technology over the past decade that experts must now educate us on what parts of the rig are automated and which are autonomous. These concepts, though related, are distinct, and technical professionals—especially decision-makers—must grasp where current capabilities stand and what challenges lie ahead.

A key challenge highlighted in this special issue is the limited interoperability between critical drilling systems. Industry experts have raised concerns that a siloed approach is holding back further leaps in efficiency. To address the problem, they have proposed that the industry adopt new software standards that would enable interoperability.

The ideas that have been translated from the drawing board into real progress and cost savings should not be taken for granted. They often come from the minds of a small number of risk-takers and were given a chance to thrive in the wild only by those curious enough to follow and build upon the knowledge.

As you attend this year's SPE conferences, we encourage you to take home new insights shared by your peers and use them to set a higher benchmark for what's possible in your own projects.

On behalf of SPE and *JPT*, I thank you for your dedication to advancing our industry in 2025—we're excited to see where your ideas and efforts will lead us next. **JPT**

Permian Basin

Operators Spill the Beans on Latest Techniques

JENNIFER PALLANICH, Senior Technology Editor

Sunset over the Permian Basin.
Source: Grand River/Getty Images.

The oil patch has few secrets.

"My career experiences taught me that there are no secrets in the oil field, and if you find something that works, good luck keeping it secret for more than a few weeks before people finally figure it out," Lance Robertson, former Endeavor Energy Resources CEO, said during SPE's 2024 **Permian Basin Energy Conference** (PBEC) in Midland, Texas.

While much may be kept proprietary, talking and sharing is common. In October 2024, operators came together at the PBEC to share how they are working to better produce the basin's shale reservoirs.

Jye Collins, Texas asset manager, Midland upstream with Chevron, said during a plenary focused on the Midland Basin that there "really are no secrets" in the Permian.

"Everyone knows what's going on pretty quickly in the Permian in the Midland Basin," he said. "They say imitation is the best form of flattery, and I say Midland's full of a lot of flattery because everybody's looking over their shoulder to see what everyone's doing."

One of Chevron's major focuses in the area is on keeping the Midland Basin going through the next evolution of west Texas energy.

The operator's development strategy has evolved as the industry has learned what does and doesn't work across the Permian. Those learnings, he noted, have led to more efficiencies.

"Efficiency has been a major part of the Midland Basin story, a major part of Chevron's story, whether we're talking about feet per day, dollar per foot unit, OPEX, efficiency has been a big component," he said.

One efficiency, he said, has been moving from simulfrac operations to triple fracture, or trimulfrac, operations. Chevron is using triple fracturing with some of its fleets, he said.

But efficiencies can compound to present a different issue: burning through inventory more quickly, which, he said, is one of the challenges associated with being successful.

Marc Lemons, asset manager for Midland Basin with ConocoPhillips, said during the same plenary that the operator has been using multivariate analysis to help model where there has been drilling "trouble time" in the past to become more predictive about potential future issues.

He said the company has also seen an improvement in drilling operations by bringing people together in the same location so they're all working with the same data.

"We also have a data, or a digital information drilling information center, that we created where we remotely control most of our rigs. We have operation personnel, geoscientists, engineers, directional drillers, all working together with real-time data. And we've seen, I think, close to a 10% improvement on our rate of penetration because of that," he said.

Tom Blasingame, 2021 SPE President, welcomes Lance Robertson, formerly Endeavor CEO, to the stage to deliver the lunch keynote at SPE's 2024 Permian Basin Energy Conference in Midland in October 2024.
Source: Jennifer Pallanich/*JPT*.

Kyle Coldiron, vice president of new well delivery at Vital Energy, said in the same plenary that the company is working to boost its inventory in the Permian Basin.

"Vital has always been known as a company that is kind of light on inventory, and so our BD (business development) strategy directly tries to address that," he said.

One of Vital's approaches to do so has been to drill horseshoe wells, or U-turn wells.

"We've now drilled five of these wells–two in the Delaware, three in the Midland," he said. "When these wells were drilled, they were actually the longest measured-depth horseshoe wells ever drilled in the world."

As an added benefit, Coldiron said, drilling one horseshoe well that stretches 2 miles will save as much as $3 million compared to drilling two shorter laterals that reach the same distance.

"Mostly that's just from your surface costs, surface casing facilities, wellheads, things like that," he said.

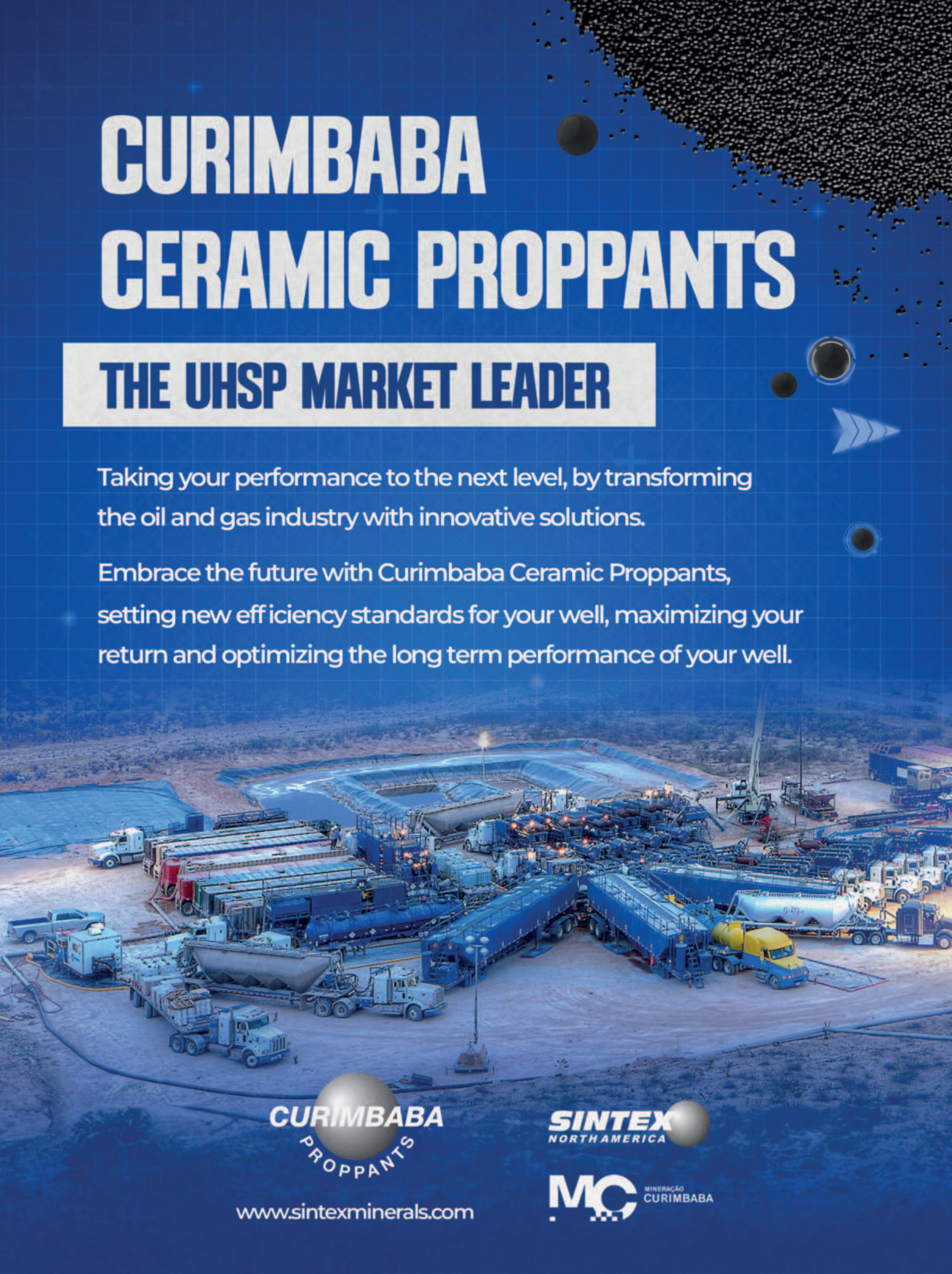
More Bang for the Buck

Travis Wolf, senior vice president and asset manager at Matador Resources Company, said U-turn, or horseshoe, wells make economic sense if reserves are landlocked, or the geology poses hazards.

"Single-mile laterals are economically challenged and have a hard time competing with the rig schedule. But if you don't have to stop the drill bit, you convert those into 2-mile laterals, and that makes a lot of economic value," Wolf said during a presentation about optimizing fairway development in the Permian. "Converting those from 1 mile into 2 miles, you definitely want to get the most return on the investment and rate of return. And so, if you put less money in, get the same amount of resources out, then that's going to definitely improve the asset value."

Many were initially skeptical about the concept of the U-turn well as a solution for landlocked reserves in the Delaware Basin, even though other companies in the area, like Shell, had successfully tried the novel approach. After

The Matador team talks about the operator's horseshoe strategy during the 2024 PBEC. Source: Jennifer Pallanich/*JPT*.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extensive vetting, research, and planning, the team pitched the idea.

Asking management how much value the company risked leaving off the table if it didn't try the approach brought unanimous buy-in, he said, and the team carried out its first trial in west Texas in 2023. The method was effective: Matador executed five more U-turn wells in 2024 and plans up to a dozen more through the end of 2025.

"We think this is a good solution and increases the value of our 1-mile land-locked sections," Matt Williams, senior reservoir engineer and area asset manager at Matador, told the audience.

In a September 2024 press release, Matador announced the company was saving roughly \$3 million per U-turn well. The company also said it is integrating trimulfracs into its completion operations, and its first remote trimulfrac operation reduced completion days by a quarter and shaved off \$1.1 million in cost compared to simulfrac or zipper-fracture operations.

Tyler Kinnon, senior drilling engineer at Matador, told the audience major decisions for drilling a U-turn well included where to place its apex and how much of the U-turn to complete. After considering the economics of placing the U-turn off-lease or on-lease, and either partially or fully completing the turn, the team opted for partial completion of the turn, on-lease, he said, adding that the team also chose to treat the U-turn as a normal 2-mile lateral and minimized changes in design.

Joe Orso, a senior geologist at Matador, said in terms of placing the lateral, the team needed to identify where the reservoir was laterally continuous and held thick net pay while also derisking faulting.

"We want to make sure that there weren't any discernible faults that we connect into or that would actually limit our geosteering efforts and make a more tortuous wellbore," he said.

Matador used its MAXCOM operation center to monitor operations, which aided in optimizing the U-turn, Orso said. "We believe our MAXCOM team and personnel are key to successfully drilling and completing U-turn wells."

Williams said tracers indicated a good and even contribution of production throughout that pilot U-turn well, with the toe contributing 45% of production and the heel contributing 55%, which he said means it's delivering more bang for the buck.

Even with such a performance, a U-turn isn't the first approach an operator should consider.

Wolf said, "When you can go straight and complete every bit of lateral that you drill, do that when you can," but if that's not possible, a U-turn well should be considered.

Big Gets Bigger

With peak oil in the US projected for 2027, Oxy Senior Vice President, Chief Petrotechnical Officer Jeff Simmons said during a panel on developing unconventional reservoirs that the industry needs technology "to keep this miracle going that's made the US economy what it is."

Technology has evolved alongside the shale play. "There's eras of technology in shale," he said.

The early phase was marked by independence and experimentation, with science struggling to catch up and explain the results, he said.

Now, the technology and science have largely caught up, and the production recipe has largely been optimized, he added. On the other hand, enhanced oil recovery (EOR) remains an issue for the play. "Why is it that EOR has not really taken off?" he asked.

Finances may play a role.

"We're competing for capital against primary drilling … as long as we have an abundance of wells to drill, it's just not going to be competitive to have a process that's slow-responding," he said.

Processes like huff-and-puff are hard to sustain, he said. "Surfactants have shown some promise but require a lot of customization. And let's be honest, we like solutions that are one-size-fits-all in this business."

Panelists Jeff Simmons of Oxy, Trey Lowe of Devon Energy, Michael Hatfield of ConocoPhillips, and John Davies of Chevron, and moderator Greg Leveille of Tidal Wave Technologies, before the "Revolutionizing the Permian Basin: Perspectives on Unconventional Reservoir Development" panel at the 2024 PBEC. Source: Jennifer Pallanich/*JPT*.

ConocoPhillips CTO Michael Hatfield said during the same panel that the Permian's story is one of innovation.

"We're blessed here in the Permian with a tremendous resource base, and we've been able to exploit it, and continue to exploit it through these technologies that have evolved over time," he said. "We couldn't have imagined 30 years ago what would have happened 20 years ago, and we couldn't imagine 10 years ago what is happening today. And I think the same is true when you look forward."

And if the industry is able to start with a large resource base, the odds are that the industry can extract even more than expected. As an example, Hatfield cited the Ekofisk field in the Norwegian sector of the North Sea, which was initially expected to produce for about a decade but which has now produced for 5 decades and has decades more in front of it.

"These big fields tend to get bigger. We tend to find ways to make them (bigger) because there's so much resource that's down there. I think we start with a big resource base, and we will find ways," Hatfield said.

He expects that as production in the US starts to decline, the industry will find ways of innovating to extend the plateau. "I don't know if we'll raise it, but I could easily see us extending it."

Right now, those operating in the Permian are targeting a rich resource base at an attractive cost and are not being forced to look at benches with higher costs, Hatfield said. "I think that day will come, and we'll see those costs drop just as we have seen costs drop over the last several decades."

As it is, the industry already has technology that enables it to carry out very precise actions from afar.

"There is a lot of technology that we use, and I think we tend to be pretty understated, in that someone described it as sitting on top of a skyscraper doing a root canal on somebody on the street. That's [similar to] what we're doing. It's pretty impressive," he said.

And the foundation for the industry is data, which helps operators refine their approach to drilling and producing wells.

"There's just a lot that we recognize we don't know, despite how sophisticated our modeling is now, that's done on top of data sets that are pretty difficult to integrate" because different functions have a tremendous amount of data in different places, he said. "How you integrate all of that is a challenge."

He said some technologies like artificial intelligence (AI), robotics, automation, quantum computing, and data are going to be transformational for the industry.

John Davies, general manager of specialized services at Chevron Technical Center, told the audience Chevron has derived a lot of value from getting its data house in order.

"It's driven so many opportunities for us, especially in the Permian. If we didn't have our data house in order, we wouldn't have been able to see and mature as many of these opportunities as we have," he said.

Devon Energy CTO Trey Lowe said one of the great things about being in the digital age is that it means the industry can do things differently.

"How do we use all the data [from] the sensors that we've spent billions of dollars installing? How do we use that data in a better way?" he asked.

Devon has been standardizing data across the company, so temperature data in Devon's systems looks similar whether the user is in Texas or North Dakota, he said. Devon also invested in its own network system to ensure all locations had high-speed internet as well as installing cameras and sensors.

"Sensors on everything. We measured everything, streamed everything, all of the operation centers," he said. "Then all of the integrated workflows came about in the subsurface spaces, so tie the different models together so that data can just flow throughout the systems."

And much of this tech is making operations safer.

"We're saving 2.5 million miles driven a year by using technology. It makes a real difference," he said.

Devon is also harnessing the power of generative AI and expects to make ChatDVN available to company employees this year.

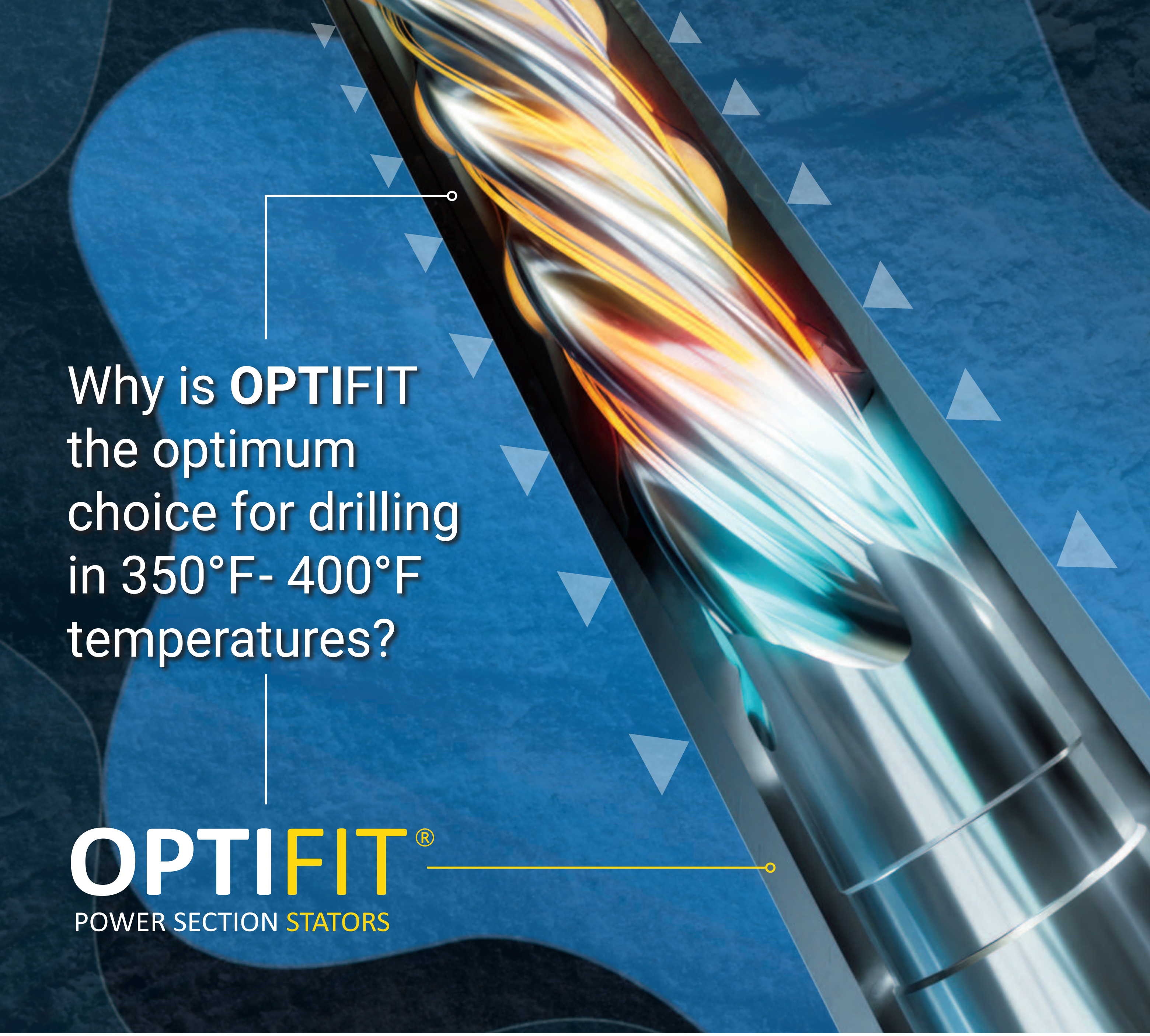
That, and other technology, makes the future look like magic, he said.

"I think some of the stuff we're doing today would look like magic to my grandpa, and I'm excited to see the things that we're going to do over the next 20 years," Lowe said.

Water, Water Everywhere

It's often said that oil companies in the Permian Basin are actually in the water business. The

ConocoPhillips Drilling Supervisor Scott Brandt at work in the Drilling Intelligence Group's advanced technology center, known as the DIG, on the Midland campus. Source: ConocoPhillips.



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unconventional shales of the Permian give up roughly 5 bbl of water for each barrel of oil.

And all that water has to go somewhere.

Cody Comiskey, earth science advisor for Chevron's Mid-Continent business unit, said during the "Injection, Pressure, and Seismicity in the Permian" panel that produced-water management is arguably the largest and most complicated issue the industry faces in the Permian.

"How are the reservoirs changing over time as we return 25 million barrels of water a day? Think about that—25 million barrels of water every day for the next 10, 12, years. That's something I don't think we've ever seen in the history of our industry. And oh, by the way, it's four times as salty as seawater. We can't just run it through a Brita (filter)," he said.

For years, the industry reinjected produced water into the reservoir in deep injection wells; however, deep injection of produced water was tied to increased seismicity.

Katie Smye, associate research professor with the Bureau of Economic Geology and co-principal investigator of the Center for Integrated Seismicity Research, said decreases in deep injection of produced water have resulted in decreased earthquake rates, although the challenge remains.

"We do still have events of magnitude 5 and above" on the Richter magnitude scale, she said. "We will continue to see earthquakes in the Permian Basin region, but the most problematic earthquake areas have been mitigated due to change in practices."

She attributed that success to operators, regulators, and academia working together to understand where and why the earthquakes were occurring, and accordingly altering operational practices.

One of those changes is to inject in shallow disposal wells rather than in deep. This however, presents other challenges, such as the pressurization of strata that an operator may want to drill through, and the fact that shallower reservoirs can't hold as much water as deeper reservoirs can.

"We need to be thinking of these injection reservoirs as a resource that needs to be managed to extend their life as far" into the future as possible, Smye said.

Ted Wooten, chief engineer with the Railroad Commission of Texas, said during the panel he expects policy change suggestions regarding injection wells "soon."

Midstream companies like Deep Blue aim to take care of produced water for operators. **Annan Pascoe,** VP of subsurface at Deep Blue, said during the panel that the company has a reservoir for injection. "This is our reservoir. It's our only reservoir. I can't make oil unless I skim it."

She said many midstream companies push technology and that Deep Blue has participated in pilot projects.

"We're doing an evaporation pilot right now. We want to inject less, because injecting less helps us preserve that reservoir and allows us to take your water longer, and that's how we make money, is just by taking the water. Because if we can't take your water, you have to shut in wells," she said.

Produced water in the Permian is a problem that requires an industrial-scale solution, **Jeffrey Thompson,** director of geophysics for Oxy, said during the panel.

In the short-term, recycling will help, while a longer-term solution will require beneficial reuse of the water, he said. **JPT**


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Operators Quantify How Completions Tweaks Drive Production

JENNIFER PALLANICH, Senior Technology Editor

With every completion, operators can fine-tune their designs. More stages or fewer? More proppant or less?

But what actually drives production improvements? Operators are increasingly seeking low-cost means of determining just that, often pushing readily available data through analytical workflows to determine what's working. And just what is it worth, anyway, to get the completion right?

As long-sought technology allowing operators to optimize their fractures in real time nears reality, the question arises of how much value a perfect fracture will bring to the bottom line.

Autonomous intelligent fracturing (AIF) capabilities require automated completions equipment responding to decisions that are based on low-cost, real-time measurements fed into optimization models which then determine the value of changing a stage's design parameters to improve it. Hess wanted to know if it was worth pursuing such a technologically ambitious goal, **Craig Cipolla,** principal engineering advisor at Hess, told an Unconventional Resources Technology Conference (URTeC) audience in June 2024.

To answer that question, Hess carried out modeling studies to estimate the value of the perfect stage, detailed in **URTeC 4044071**. That study used the uniformity index (UI), a metric that quantifies completion effectiveness of the stages.

While engineers design completions with a goal of reaching a perfect UI of 1.0, "very rarely do we see a uniformity index of 1. We see something less than that," Cipolla said. "To understand the relationship between a very low UI, a perfect UI, and median UI, we didn't have that range of field data to do that. So, we did a modeling study."

The study was conducted on five Middle Bakken wells, where Hess' fiber-optics data suggest current UIs are around 0.7. The study set a technically achievable perfect UI at 0.93—0.99, a baseline UI at 0.8, and a poor UI at 0.2–0.3 to estimate the "cost of not getting it right," he said.

When the UI is poor **(Fig. 1),** some clusters may receive little fluid while in a perfect scenario, all clusters receive the same amount of fluid. Yet a perfect UI does not guarantee a cluster will fracture uniformly, so fracture morphology was also a consideration.

To predict the production improvement and value of the perfect frac stage for the five Middle Bakken wells, Hess used a fully coupled, calibrated hydraulic fracture-reservoir simulation model along with a second study using the same reservoir simulation model with pre-existing fractures. **Fig. 2** illustrates fracture lengths and drainage patterns for perfect, low, and base case UIs.

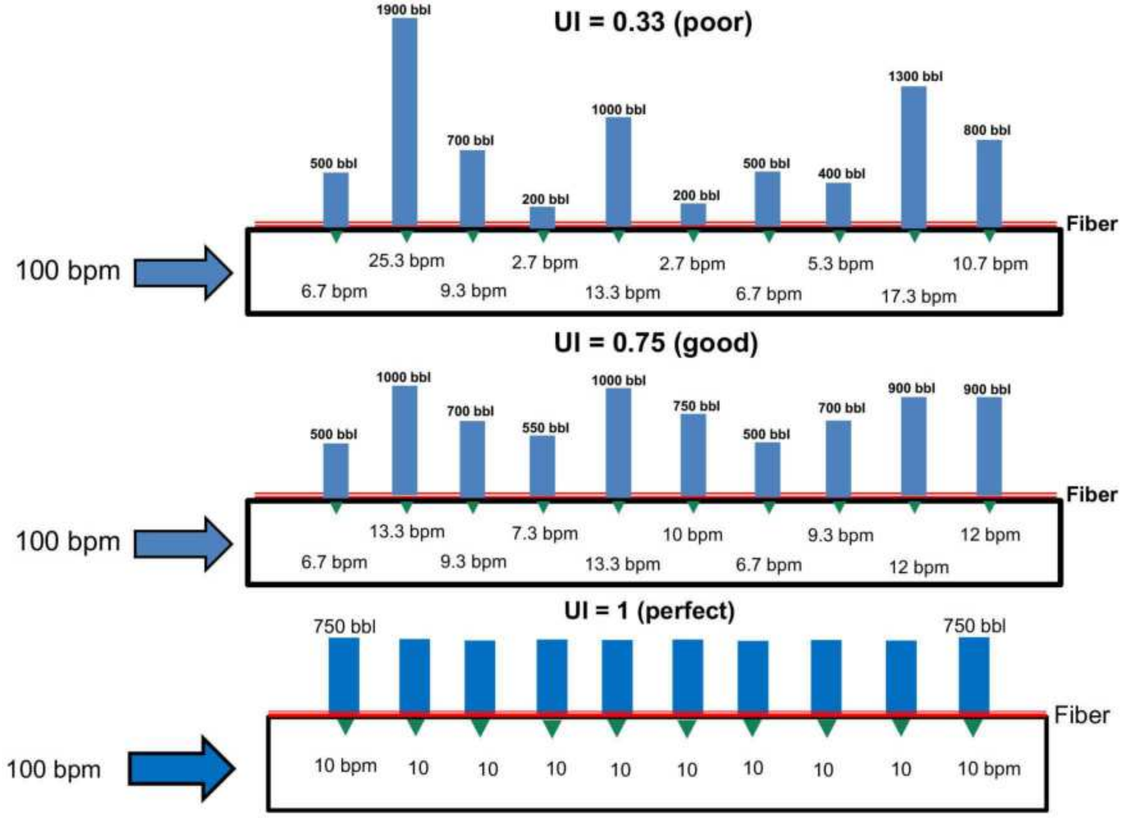


Fig. 1—Illustration of poor, good, and perfect fracture stages, showing fluid distribution can vary considerably across clusters even with relatively good UI. Source: URTeC 4044071.

The second method showed much less heterogeneity in fracture geometry than the fully coupled model. According to the paper, the first model's results were the most realistic, and the second model made it possible to compare results and ensure conclusions weren't dependent on

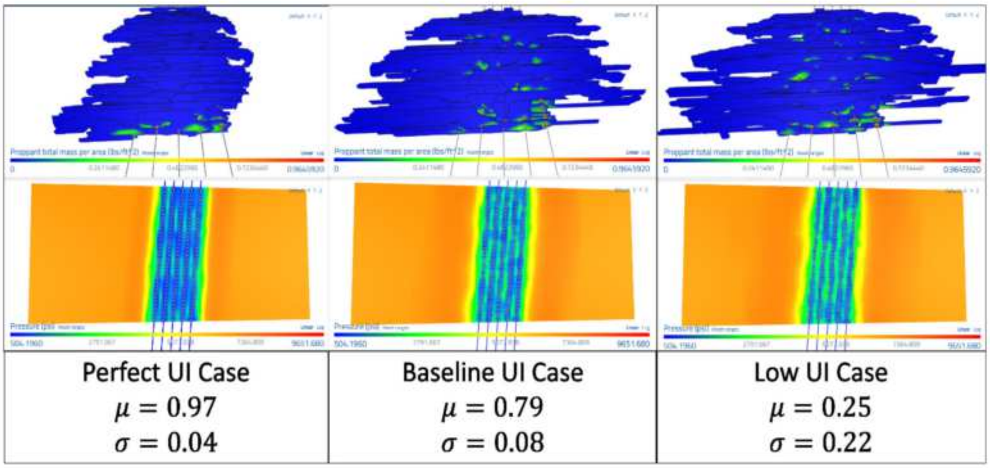


Fig. 2—Fully coupled model results showing fracture geometries (upper graphics) and drainage patterns (lower graphics) for perfect, baseline, and low UI cases. The perfect UI case shows very uniform fracture lengths and drainage. The low UI case shows highly variable fracture lengths and uneven drainage pattern, while the base UI case shows more uniform fracture lengths and drainage. Source: URTeC 4044071.

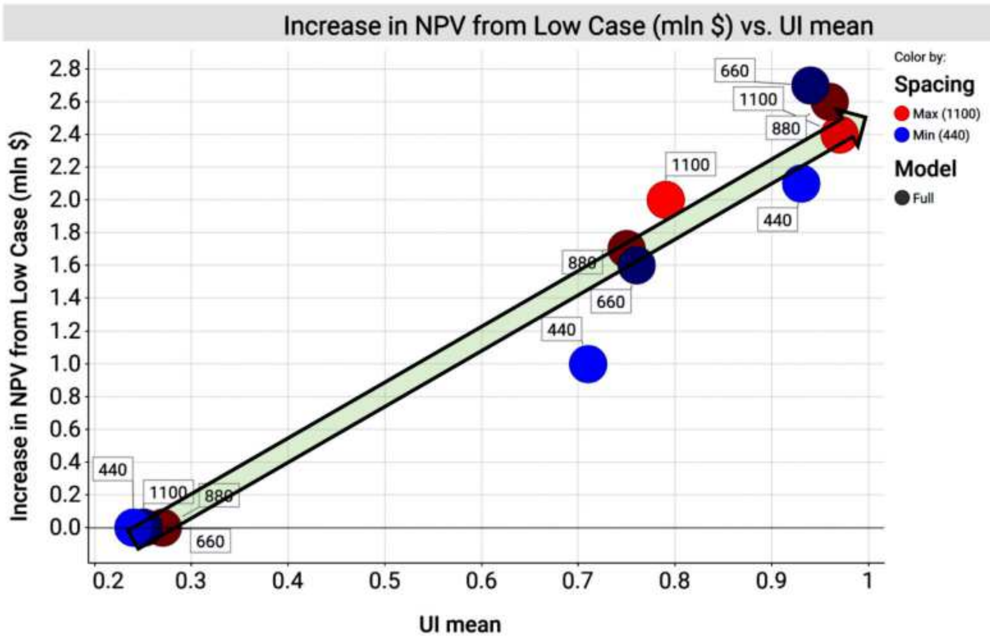


Fig. 3—Every 0.1 improvement in UI is predicted to increase first-year production and add to the well's net present value. Source: URTeC 4044071.

fracture geometry details. Although the results in the two models varied, the study predicted that increasing a UI from 0.25 to 0.75 would deliver a 10% hike in first-year production. The paper went on to say the benefits of increasing the UI are less as the average UI improves.

"Every 0.1 improvement in UI is predicted to increase first-year production about 2.5% and add about $0.3 million in NPV" (net present value), the authors wrote **(Fig. 3).**

Cipolla said the range between "what could be bad and what could be very good" is significant and represents material numbers. "Is this worth the effort?" he asked. "The answer is 'probably.'"

That understanding encourages further pursuit of AIF completions. But, Cipolla said, achieving that requires advances in three areas: low-cost, real-time measurements; value optimization models; and automated completions equipment.

The first of those, he said, is necessary to inform engineers about "uniformity correction, geometry, all the things we need to know to understand how a particular stage is progressing."

Historically, the industry has considered permanent cemented fiber optics a reliable tool for assessing cluster performance and flow distribution to evaluate the success of completions. The fiber UI describes how well each cluster is being stimulated, but obtaining this information can be costly and require significant operational time.

Hess sought to determine whether high-frequency pressure data from the surface could serve as a proxy for fiber UI, Cipolla said during a 2024 URTeC team presentation of URTeC 4044703.

To determine whether such a proxy would be useful, Hess assessed data from a trio of Middle Bakken wells with permanent cemented fiber optics and high-frequency pressure transducers to obtain acoustically derived measures of perforation efficiency and UI. Cipolla and coauthors concluded acoustic UI is an easily implemented and cost-effective method for assessing cluster-level fluid distribution during hydraulic fracturing treatments.

To calculate the acoustically derived UI, the coauthors first had to determine the perforation friction and resulting perforation efficiency for the three wells. They did so by analyzing the acoustic signal resulting from a single rapid and

small rate drop that happens through the course of the stage and the resulting water hammer using high-frequency pressure transducers. With the perforation friction and perforation efficiency determined, the coauthors calculated an acoustically derived UI via a four-step process.

They analyzed planned and unplanned rate changes to calculate pipe friction, perforation friction, and perforation efficiency for each observed rate drop. They calculated perforation efficiency change throughout the stage based on friction analysis and pumping data. They determined the fluid volume evolution for each cluster using perf-efficiency and slurry-injection data. Finally, they calculated the uniformity of stages using cluster-level volumes.

Coauthor Kinleigh Fatheree, completions manager at Seismos, told an URTeC audience in 2024 it is a simpler method to gather the data in a noninvasive way. “We have high confidence” in the predictions, she said.

In the three-well study, individual well UI correlations ranged from 0.80 to 0.96 **(Fig. 4).** She said the correlations, with very similar values, are very promising. “As we continue, we expect correlations to stay the same or get better.”

Coauthor **John Lassek,** a senior engineering advisor at Hess, told the audience the study yielded insights for continuous improvement. “As we are able to gather a lot of data, we’re able to make improvements as we go along,” he said, noting learnings can be quickly implemented in the same or next well.

The main takeaways from the study fall into two buckets, he said. The first relates to design changes that can increase UI. If the normal UI range for stages in a well is 0.7 to 0.9, but stage UIs drop down below 0.5, “that’s an issue. We want to do something about that,” Lassek said.

He said some of the stages in the study had screenouts, reflected by drops in UI. In that case, changing the proppant resulted in increased UIs. The changes weren’t made in real time. It took several stages to “get back up to where we wanted

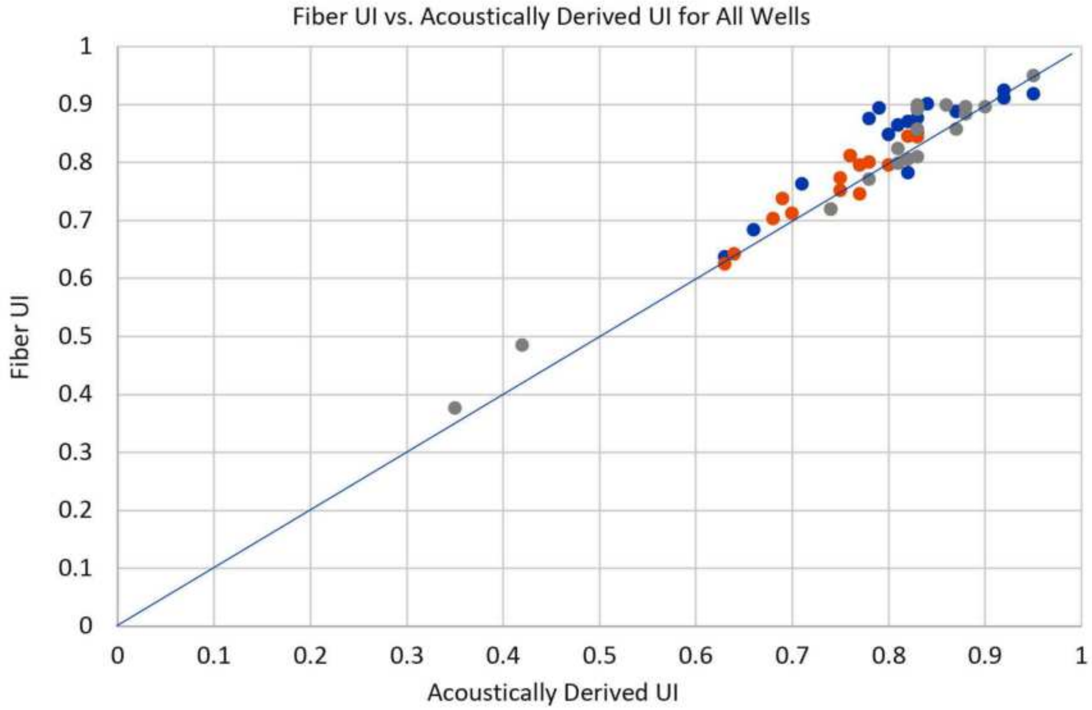


Fig. 4—Fiber UI vs. acoustically derived UI for the three wells with 1:1 comparison. Source: URTeC 4044703.

to be," Lassek said. "Going from 0.38 to 0.72 is definitely a step in the right direction."

The second takeaway involves flow area interpretations where UIs were attaining "physically impossible" levels, he said.

"Acoustic UIs started systematically increasing toward 150%," he said. These values related to plug failure signatures associated with dissolvable plugs, so stages using dissolvable plugs were excluded from the dataset.

Overall, the study concluded the acoustic UI method was easily implemented. "We've gathered quite a bit of data on this now," Lassek said. "Low-cost acoustic UI may be a proxy for much-higher-cost fiber UI measurements."

The method is also scalable, he said, and Hess hopes it will help make AIF possible. "Acoustic UI may be a key enabler of real-time completion optimization and an important leap forward toward the ambitious vision of AIF," he said.

Evaluating Cluster Efficiency With Existing Data

Saudi Aramco is another operator on the hunt for a cost-effective and streamlined means of quantifying cluster efficiency.

Abdulrahman Alowaid, petroleum engineer at Saudi Aramco, told a 2024 URTeC audience the company has developed a noninvasive, free, eight-step workflow that uses existing raw stimulation data to effectively evaluate cluster efficiency in unconventional wells stimulated by multistage hydraulic fracturing.

"Results can be generated automatically, without the need to do in-house processing, especially engineering work," he said. "And finally, we wanted to have a process that can be automated."

URTeC 4032879 describes the workflow **(Fig. 5),** which requires treating pressure, pumping rate, and friction reducer concentration data to estimate the cluster efficiency in plug-and-perf unconventional wells with "a high degree of accuracy."

According to the paper, the workflow hinges on the key assumption that "total friction is a function of pipe and perforation friction only." The workflow neglected near-wellbore friction and tortuosity in total frictional loss estimations.

In one application, Aramco used the workflow on a well stimulated with multistage hydraulic

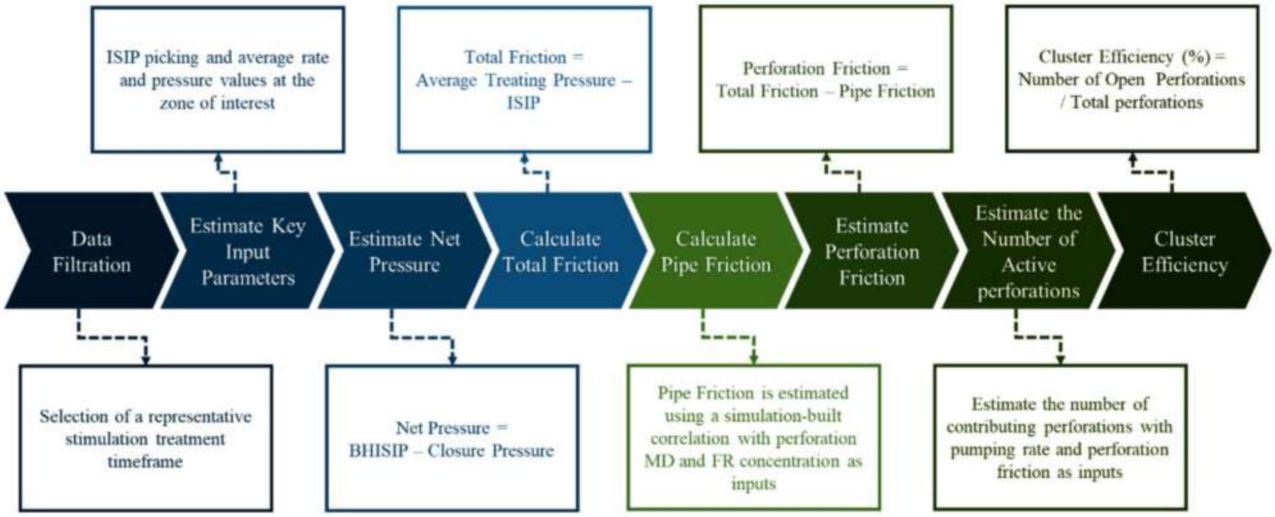
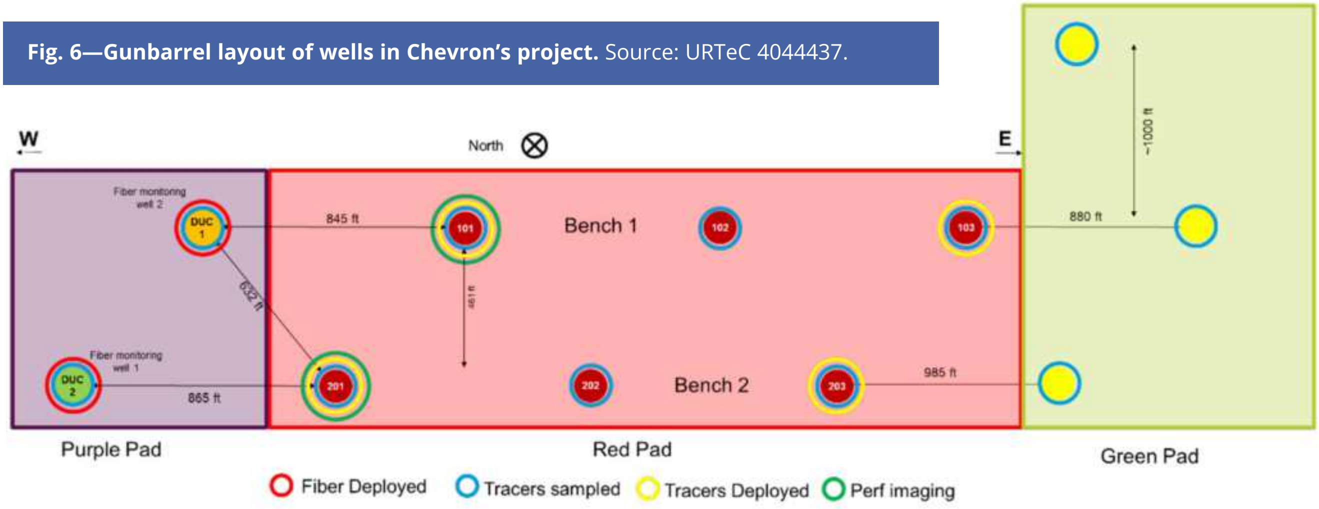


Fig. 5—The cluster efficiency estimation workflow uses values that include instantaneous shut-in pressure (ISIP), friction reducer (FR), and measured depth (MD). Source: URTeC 4032879.

Fig. 6—Gunbarrel layout of wells in Chevron's project. Source: URTeC 4044437.



fracturing that had 45 perfs in the first design, 30 in the second and 22 in the third.

"Design 1 with the highest number of perforations per stage, had the lowest cluster efficiency, followed by design 2, then design 3 with the highest cluster efficiency and lowest number of total perforations per stage. Perforation friction was lowest for design 1 followed by design 2 then design 3," the authors wrote. The authors attributed this to the number of perforations for each stage, indicating an inverse relationship between the number of perforations and perforation friction.

Further, the authors stated, the outcomes were "almost identical" to the results of the stepdown test for the second and third designs, varying by 4% and 1%, respectively. The variance in cluster efficiency for design 1 as a whole was 19%, but by assessing that design's perf stages closer to the toe, results were "only 4% shy" of the stepdown test cluster efficiency, according to the paper.

Fluid or Proppant as Productivity Driver?

Chevron, aiming to remove uncertainty from its completions designs, created an experiment to answer the question of whether fluid or proppant had a larger impact on well productivity.

URTeC 4044437 outlines the experiment and the surveillance methods used to address uncertainty around cluster efficiency, fracture geometry and growth rate, and fracture drainage volume.

James Cooper, completions optimization advisor at Chevron, told a 2024 URTeC audience five hydraulic fracture designs varied the amount of slurry per cluster and total proppant-to-fluid ratio to be used in five wells.

The first was a baseline. Variations included: 40% reduced proppant quantity only, 40% increased proppant quantity only, 40% reduced fluid and proppant quantity, and 40% increased fluid and proppant quantity. The variations covered typical values the industry uses in the Permian Basin. Design parameters like cluster spacing, number of clusters per stage, perforation design, or pump rate remained unchanged.

Chevron selected two six-well pads, each of which had three wells in upper Bench 1, and three wells in deeper Bench 2. All were about 2.5-mile-long laterals. According to the paper, the Red Pad wells were stimulated first and were the focus of all measurements and observations, with the Purple Pad stimulated next using sealed drilled but uncompleted wells for fiber-optic measurements **(Fig. 6).** Nearby, tracer sampling was carried out on the Green Pad parent wells to the east. The Green Pad wells had been in production for about 2 years before hydraulic fracturing started at the Red Pad.

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For surveillance, Chevron opted for ultrasonic image logging, disposable fiber optics, and liquid- and oil-soluble tracers, which all provided data quality, operational efficiency, cost-effectiveness, and risk mitigation.

Chevron used ultrasonic imaging to calculate the cluster efficiency and determined the results aligned with observations from other operator-developed Permian wells that used the same limited-entry design. According to the paper, the results indicated a high cluster efficiency and set a critical baseline for analysis of subsequent data.

The operator used direct acoustic sensing observations from fiber optics and volume-to-first-response analysis to understand fracture geometry and growth rates.

Almost all stages contained fractures that grew laterally, but few grew "at a large downward extent," Cooper said. "The designs are generally achieving the lateral growth we expected."

According to the paper, shallow bench fractures likely grew more in height due to lack of vertical stress bounding; there was limited downward growth from the shallower bench to the deeper bench; and the vertical containment by the shallower fracture system promoted strong lateral fracture growth in the deeper bench.

The authors concluded that regarding fracture drainage volume, the fluid injected early in large-volume stages has extremely low recovery, and that "stimulated volumes within well spacing is connected, propped, and draining in the first 6 months regardless of design with minimal correlation to design." Further, the authors stated it remains unclear what impact design has on far-field drainage, particularly over the long term.

The authors also concluded that within the range of designs pumped, the correlations are weak and fail to indicate a clear preference for fluid or proppant as a productivity driver.

"There's a lot of great learnings," Cooper said. But, "looking at the different designs, I really didn't see anything major distinguishing on a design level, so I can't come out and say one design is better than the other."

As part of its effort to better understand and optimize hydraulic fractures, Chevron deployed liquid and proppant tracers in wells pumped with five different designs.

URTeC 4055456, presented by **Lokendra Jain,** senior petroleum engineer at Chevron, outlines how the tracers were deployed

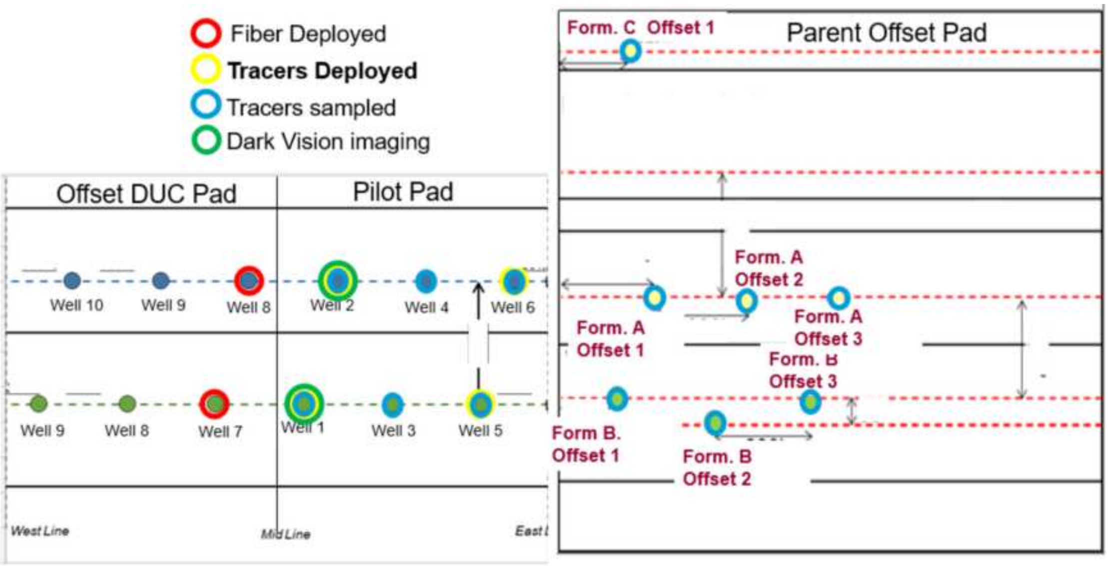

Fig. 7—Pad layout showing various surveillance technologies in use. Source: URTeC 4055456.

and interpreted to quantify fracture geometry and subsequent drainage.

The information is important, Jain said, because answers could help optimize well spacing as well as the slurry per cluster and fluid-to-proppant ratio. "Understanding how the fluid moves, how the proppant moves, allows us to change the design," he said.

Each of five designs in four wells on a six-well west Texas pad received unique tracers, as well as additional surveillance systems **(Fig. 7).**

The authors expected tracers pumped in early segments for larger fluid-intensity pump stages to show higher recoveries compared to the tracers injected later in all the designs; however, some parent offset wells, such as the Formation C well, showed the expected response while the Formation B offset well showed the opposite. According to the paper, the hydraulic communication results indicate that "despite the fluid-intensity variations from smallest to biggest design, the tracers pumped in all segments can reach the offsets establishing good hydraulic connectivity."

When it came to drainage or propped communication, the authors expected tracers pumped in early segments for larger fluid-intensity pump stages to show lower recoveries compared to the tracers injected later in all the designs. According to the paper, responses were not as expected at the offset wells, which may be because the wells were not all put on production together but rather over 2 months in a staggered fashion. The authors said despite the proppant-intensity variations, propped drainage areas were drained by the offsets, establishing good propped connectivity.

Proppant oil tracer was deployed in two wells, and production was mapped to the different designs. The authors found "from when the wells were put on production to 6 months of production, all the designs have performed relatively similarly." Further, the authors stated, there was no significant impact observed when it came to proppant-to-fluid ratio, proppant intensity, or fluid intensity when the wells were put on production or 6 months post beginning production.

Jain said of the range of designs pumped, the correlations were weak and didn't indicate a clear preference for fluid or proppant as a productivity driver in the study. "The impact of designs on far-field drainage is unclear, especially in the long-term," he said. **JPT**

FOR FURTHER READING

URTeC 4032879 Perforation Efficiency Quantification Utilizing Raw Stimulation Data for Hydraulically Fractured Unconventional Wells *by A. Alowaid and T. Altayyar, Saudi Aramco.*

URTeC 4044071 The Perfect Frac Stage, What's the Value? *by C. Cipolla, M. McKimmy, and J. Lassek, Hess; and A. Singh and M. McClure, ResFrac Corporation.*

URTeC 4044437 Accelerating Optimization of Unconventional Fracturing Design With Multicomponent Subsurface Surveillance: A Case Study From the Permian Basin *by J. Cooper, A. Singh, L. Jain, J. Haataja, M. Craven, K. Belcourt, and T. Stom, Chevron; and S. Galimzhanov, Tengizchevroil.*

URTeC 4044703 Case Study–Using an Acoustically Derived Surface Metric To Approximate Fluid Distribution Uniformity During Stimulation *by C. Cipolla, M. McKimmy, and J. Lassek, Hess; and K. Fatheree, S. Aghdam, J. Kroschel, and M. Khan, Seismos, Inc.*

URTeC 4055456 Novel Tracer Application and Analysis Methodology To Quantify Creation and Drainage of Hydraulic Fracture Area and Growth Rate *by L. Jain, J. Cooper, and A. Singh, Chevron.*

High-Tech Meets Low-Tech To Boost Well Efficiency

JENNIFER PALLANICH, Senior Technology Editor

Expand Energy Corp. is combining high-tech and low-tech methods to drive down drilling and completion times and costs.

Josh J. Viets, Expand's executive vice president and chief operating officer, said at the 2024 Unconventional Resources Technology Conference (URTeC) in Houston that the operator aims to turn lots of small time and money savings into a meaningful impact on the bottom line and drilling time.

"You have to really methodically chip away, and, ultimately, what you hope is a lot of really small wins will ultimately add up and translate into something bigger," he said.

Since 2007, Expand has improved its Haynesville shale drilling capital efficiency by about 85%, Viets said. Then, early wells would break even when natural gas prices were around \$10, while now, that threshold is about \$2, he said. A lot of the early savings came from low-hanging fruit such as going after the best rock, he added.

But advances in artificial intelligence, machine learning, and data analytics are helping Expand drill better wells and avoid unnecessarily tripping out of the well.

Historical drilling parameter data from more than 1,000 wells is informing a predictive tool called Forerunner that Expand drilling engineers are using to achieve optimal drilling results.

Josh J. Viets
Executive Vice President and Chief Operating Officer
Expand Energy Corp.

"Forerunner is able to provide predictions and rate of penetration at any point in the lateral," Viets said. "If you think about me being out on the rig, having that guidance, am I ahead of or behind where I should be … [knowing that] would be incredibly helpful for the driller."

A second high-tech tool, Seer, is helping Expand avoid bottomhole assembly (BHA) failure. Seer makes predictions in real time about the condition of the BHA, he said.

For example, if a drilling engineer is unhappy with the rate of penetration but Seer indicates the BHA is in good condition, the engineer can continue drilling slowly rather than spending hours tripping out of hole, he said. At the same time, it is "incredibly beneficial" to be able to pull tools out of the hole preemptively ahead of a failure.

Advanced analytics have helped guide Expand in development decision making.

Cluster spacing, stage lengths, drawdowns, and other elements can be assessed quickly and optimized for every well, rather than using a one-size-fits-all strategy, he said.

"We continue to see the use of advanced analytics making its way throughout our business," Viets said.

Expand is also using edge computing to process data on site, he said.

"These tools are changing the way we work," he said.

Low-Tech Savings

"Oftentimes, when we talk about innovation, you know, it needs to be high-tech. We need to be shiny, to be exciting," Viets said. "Sometimes, low-tech solutions can actually really benefit us as well."

Improvements such as continuous pumping made it possible to complete wells more quickly but also revealed bottlenecks in the supply chain that led Expand to use a low-tech solution.

"We simply could not logistically get enough sand to the locations to keep up with how fast we were pumping," he said. "Simply piling sand on occasion is the better option."

Piling sand on location is saving between $100,000 and $200,000 per well in addition to eliminating 360 truck trips per two-well pad when compared with using a sand box system, he said. **JPT**

Editor's Note: Since the date of this article's original publication, Chesapeake Energy has rebranded as Expand Energy Corp. following its merger with Southwestern Energy Company. All references to Chesapeake in this article have been updated to reflect its current name.

Innovative Approach To Increase Well Productivity by Adapting Drilling Targets and Completion Methodology

Dustin Aro, Precision Petroleum Solutions; **Tim Hilton** and **Connor Bradham,** Steward Energy II; and **Robert Gibbons,** Stage Completions

The discourse regarding US land exploration and production has tended to primarily focus on shale development. While this has pushed the industry to adopt many technologies or applications, the general recipe has been to be faster and cheaper with hopefully more predictable BOE/ft production. However, there are limitations with this approach as it tends to boil down to a choice of substitution rather than true engineering to improve return on investment or improved net present value.

The relationship of parent and child well production has introduced a variable that does not necessarily respond to faster and cheaper. In fact, operators may agree that a dissolvable frac plug has application to reduce completion costs while completely disagreeing on the methodology to manage field development and the parent-child interaction.

Extensive field study and calibration can determine an optimal solution with varying degrees of predictability (SPE 211899).

For example, reservoir depletion and fracture communication can be difficult to accurately plan for in advance. These and several additional parameters are specific to a section, field, or bench and the design and planning process begins anew when drilling locations move a sufficient distance away from the asset in question.

The best outcome during the drilling and completion of a child well is to limit the negative impact on parent well production while delivering an economically viable addition to existing production. Acceptable ranges of underperformance with the child well vary, but can be summarized as 20 to 30% less than the parent well (SPE 209171).

Additionally, contact from an offset child well fracturing operation can detrimentally affect parent well production temporarily or permanently by increasing water production and decreasing hydrocarbon production.

Introduction

This case study presents the development of a methodology for optimizing and controlling the hydraulic fracturing process's parameters by increasing cluster efficiency to 100% and overcoming formation leakoff with eight to 10 times rate per cluster when compared with industry standards.

The developed framework is validated through field completion and production data taken from wells located on the Northwest Shelf, within the San Andres formation, specifically straddling the state line of New Mexico and Texas with operations primarily in northeast Lea County, New Mexico, and Yoakum County, Texas.

For the purposes of this study, parent wells are wells drilled during Segment 1 (2013 to 2016) and/or the first wells drilled in a section.

Child wells are defined as any subsequent wellbore placed in a section amongst current

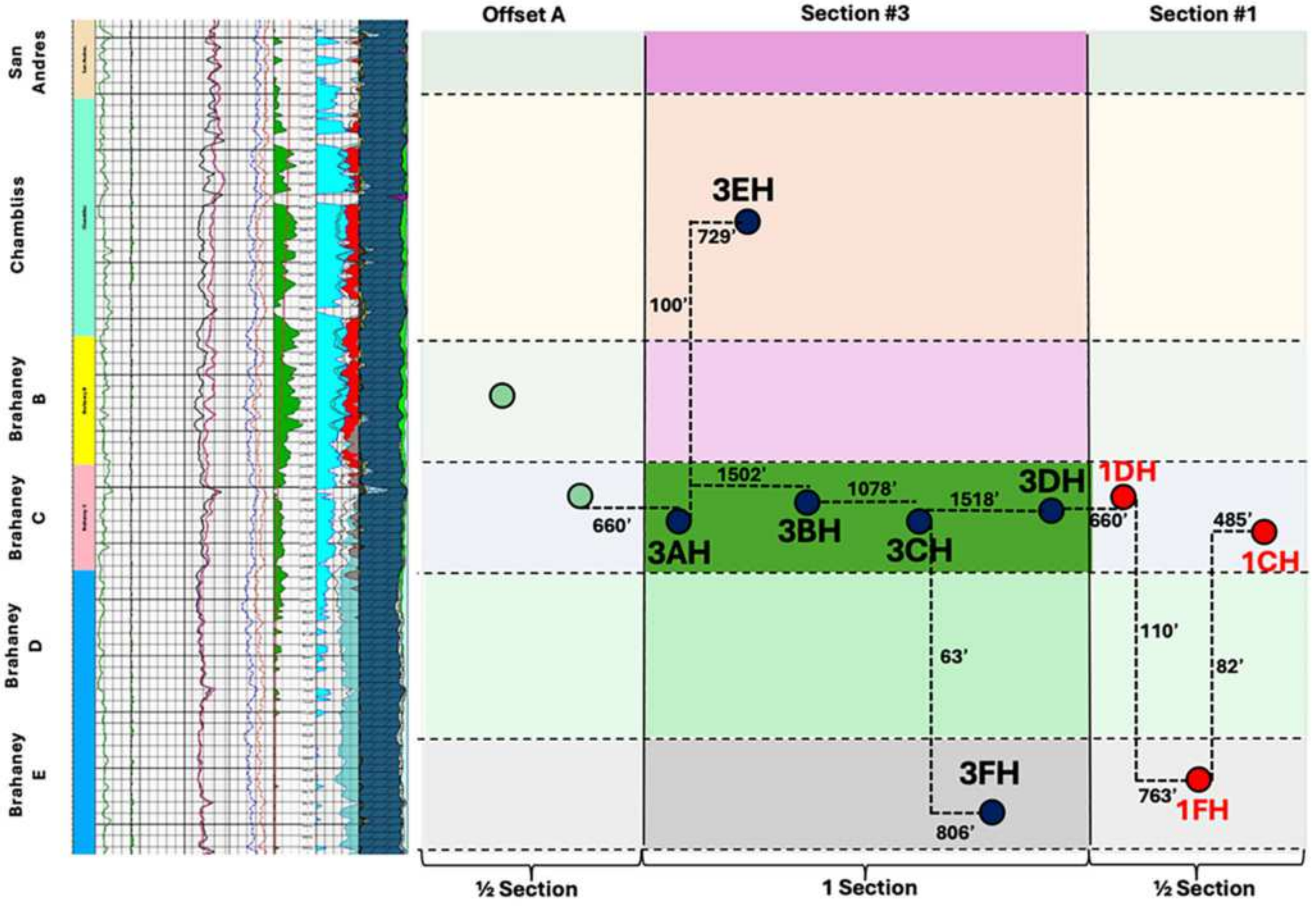

Fig. 1—Drilling targets for wells drilled between 2013 and 2016. Source: Steward Energy.

producers Segment 2 (2017 to 2020) and Segment 3 (2022 to 2023).

The offset true vertical depth (TVD) of the child wells relative to the parent wells is less than 100 ft and no geologic barrier exists, thus the contribution to production is from the same rock matrix regardless of well vintage.

Segment I: Drilling and Completion Operations (2013–2016)

Initial horizontal development in the San Andres experienced production coming online with high water volumes that in many instances exceeded 90% water cut. Legacy vertical well development identified the high water saturations, so this did not come as a surprise.

Where to land a horizontal well became the priority to hopefully reduce produced water volumes and improve economics. The general approach was to turn the bit 90° at the base of the Brahaney C bench within the overall San Andres formation and use a four-well "wine rack" (e.g., wells A-D in **Fig. 1**). This approach looked to take advantage of the frac height growth upward while keeping the well targeting the very bottom of the residual oil zone (ROZ).

Conventional plug and perf with a ball-drop mechanism isolated and prepped each stage prior to the frac stimulation. Frac designs built on the historical completion work in the vertical San Andres development. The design even included a gelled acid bullhead in front of the proppant schedule.

This is a good example of checking a box in fracturing theory as opposed to understanding the application and quality control environment. A 12# linear gel and 15# crosslink gel were the primary proppant carrying systems. The stimulation metrics are as follows:

- 383 lbm/ft and 11.7 bbl/ft @ 60 bbl/min
- 19% 100 mesh, 29% 40/70, 52% 30/50 sand
- 21 bpm/cluster
- 391-ft stage spacing (plug to plug)

Segment II: Drilling and Completion Operations (2017–2020)

Drilling operations focused on cost reductions and efficiency gains with no major changes in mud systems or procedures. Beyond these considerations, an impactful decision was made to ignore the common concern regarding lateral TVD and where to land the well.

The Brahaney D bench became the center of focus to conceptually improve the gross pay zone stimulation. Offset sections to that exhibited in Fig. 1 have single wells at TVDs between Wells A-D and Well F to test drifting away from the Brahaney C.

Conventional plugs were primarily used with some dissolvable plug testing. The low reservoir temperature (105°F) is not ideal for dissolvable plugs. Overall results were mixed, and composite frac plugs remained the preferred option.

The frac design made a shift towards a more hybrid approach by utilizing slickwater while also increasing near-wellbore proppant pack conductivity by adjusting the following criteria:

- 750 lbm/ft and 16 bbl/ft @ 50 bbl/min
- 3 to 5% 100 mesh, >95% 30/50 (thin bed design) or 20/40 (infill/child well design)
- Adjusting % of crosslinked fluid and gel loading, e.g., 18# or 12# instead of 15#
- 16 bpm/cluster
- 243-ft stage spacing (plug to plug)

Post-frac drillout operations were becoming a high-risk operation to forward circulate and effectively clean the wellbore with reservoir pressure being insufficient to maintain the hydrostatic pressure to maintain annular velocity targets. Unfortunately, the formation began taking so much fluid that another solution had to be implemented.

Segment III: Drilling and Completion Operations (2022–2023)

Promising results from Segment II wells led to disregarding conventional petrophysical analysis and landing wells shallower at the top of the ROZ in the Chambliss or deeper beyond the water/oil interface in the Brahaney D/E (these wells are labeled E/H in Fig. 1).

The decision was made to move away from isolating frac stages with plugs. Each well included the deployment of a multistage, single-point completion system with fully dissolvable downhole elements.

The early execution and results in other sections indicated that pushing max pressure with max rate was more desirable for improving production. Direct collaboration with the completion tool service company allowed fracturing rates to increase over time from 35 bpm to 65 bpm and up to 95 bbl without compromising consistent frac stage execution.

Volumes deployed per well and cluster/perforation averaged as follows:

- 984 lbm/ft and 20 bbl/ft
- 100% 30/50
- >80 bpm/cluster (single point entry)
- 160-ft stage spacing (sleeve to sleeve)

Following the multistage fracturing treatment, a conventional workover rig was outfitted with a mule shoe with internal custom carbide teeth to wash down to the toe depth, minimizing fluid on formation while ensuring no restrictions were present in the lateral.

As per **Fig. 2,** the improvement over time is significant. The increase in production occurs despite the operator producing from the same formation, drilling the same lateral lengths, and deploying the same artificial lift over a 10-year period. All the while capturing a greater share of oil price trends.

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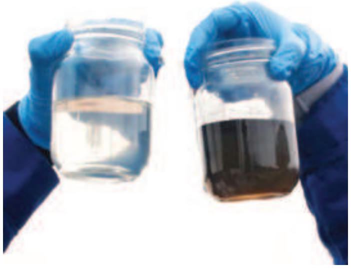

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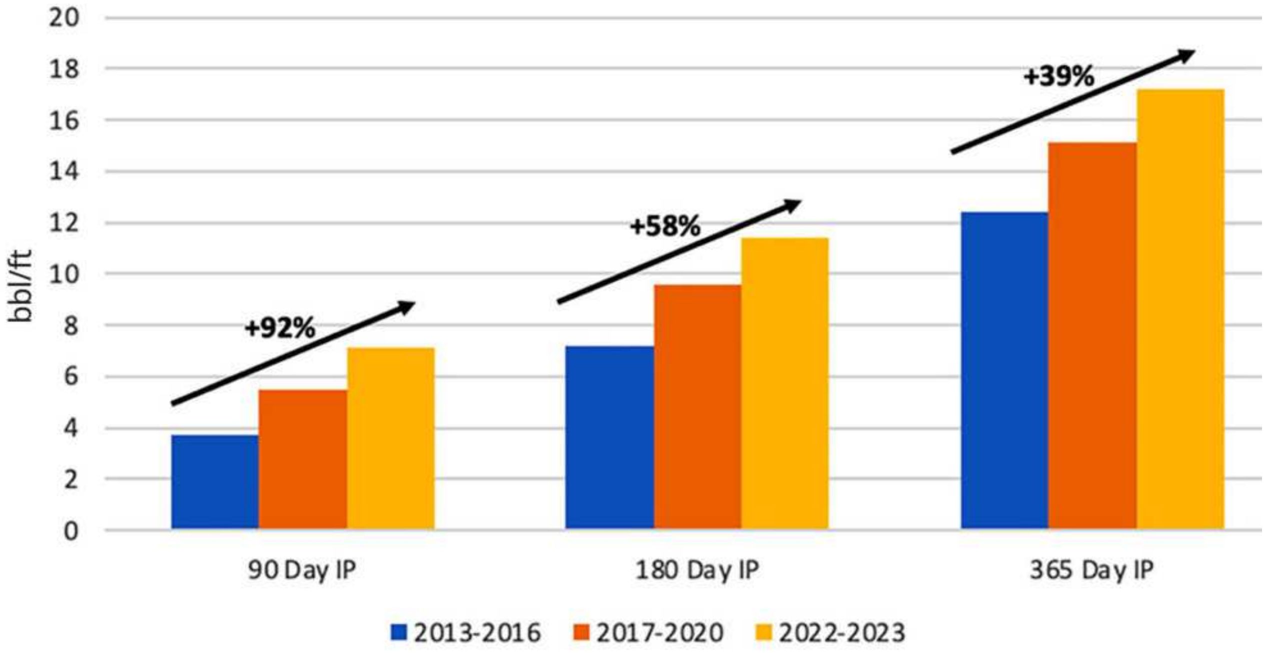


Fig. 2—Initial production (IP) comparison over time. Source: Steward Energy.

Conclusion

The ability to outperform existing parent wells is a combination of allowing the propped fracture to access as much gross pay as possible and concentrating the fracturing properties into an extremely small window. It has been well documented publicly that fractures tend to grow upwards and take on a penny, or coin, shape.

The addition of gross pay was achieved by using the fracture-height growth tendency in combination with lowering the target zone to the lowest feasible point to exploit the San Andres formation.

Accessing more rock beyond the propped fracture height was accomplished by recreating the concept of an extreme limited-entry design and controlling frac propagation beyond conventional methods. The ability to control the fracture initiation in the near-wellbore region created a more productive fracture network in the reservoir.

While in-depth science and modeling can aid in frac execution, in many cases it is simply the action of meeting new challenges with innovative approaches.

Increasing sand and water volumes per foot while decreasing the reliance on high-viscosity crosslink to pump the designed sand concentrations, through a single-point completion methodology, improved contact with the reservoir while reducing post-frac costs.

The results achieved during this specific field development hinged on the willingness to challenge accepted practices and introduce measurable design changes. Dynamic engineering and working collectively with a service provider were also necessary elements that enabled the operator to grow production and increase reserves. **JPT**

FOR FURTHER READING

SPE 209171 Parent-Child Well Relationships Across US Unconventional Basins: Learnings from a Data Analytics Study *by J. Cozby, EOG Resources; M. Sharma, The University of Texas at Austin.*

SPE 211899 Results from a Collaborative Parent/Child Industry Study: Permian Basin *by M. McClure, ResFrac Corporation; M. Albrecht, SM Energy; C. Bernet, Ovintiv; C. Cipolla, Hess Corporation; et al.*

AUTHORS

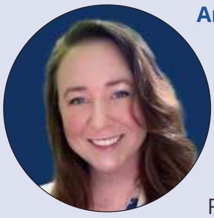
Dustin Aro, P.E., is a vice president of operations for Precision Petroleum Solutions and has over 15 years of managerial and technical design/execution experience in high-volume US onshore drilling and completions operations management. His career includes US and international field/on-site and in-house roles with major and independent operators. He has also held executive level positions at multiple oil and gas engineering consulting firms that have provided strategic, technologically advanced oil and gas well completion design and execution in both unconventional and conventional reservoir settings. Aro is a licensed professional petroleum engineer in the state of Texas, having received his credentials under the Texas Board of Professional Engineers and Land Surveyors certification program. He holds BSc degrees in engineering and business administration from Michigan Technological University. He can be contacted at dustin.aro@ppsog.com.

Tim Hilton, P.E., is the vice president of operations at Steward Energy II, with over 15 years of leadership in the oil and gas industry. As an innovative engineer and operational executive, Hilton specializes in managing engineering and operational functions, including drilling, completions, production, and facilities with a proven track record of driving efficiency and growth. He has played key roles in building and scaling multiple private equity-backed companies, with successful exits demonstrating the ability to scale operations with a bottom-line focus. At Steward Energy II, he has overseen significant growth, driving production from 500 BOE/D in 2016 to over 29,000 BOE/D in 2023. He led the development of operational teams, budget management, and advanced engineering solutions, including a successful redesign of completions and artificial lift systems. Hilton's efforts have resulted in increased productivity, reduced costs and extended equipment run times. A licensed professional engineer in Texas, he holds a BSc in mechanical engineering from Mississippi State University.

Connor Bradham is a senior operations engineer at Steward Energy II, with over 8 years of experience in oil and gas operations. His core competencies include production and operations optimization, reservoir engineering, and leading development programs, such as horizontal well projects across various fields and basins. With a strong background in drilling, completions, recompletions, and production management, Bradham excels at enhancing operational efficiencies and minimizing costs. His extensive experience working with multiple operators across different basins has been instrumental in driving strategic initiatives that improve well performance and profitability. He holds a BSc in petroleum engineering and minors in mathematics and mechanical engineering from the Texas Tech University.

Robert Gibbons leads sales and business development efforts for Stage Completions as an energy industry veteran with over 25 years of oilfield services experience in completions and interventions. He has held senior roles in both sales and operations and his expertise spans from startups to large enterprise business-to-business growth. With a proven track record of managing multimillion-dollar portfolios, particularly in the US land and Gulf of Mexico regions. Gibbons is known for building strong, collaborative relationships with clients. He holds a BSc in industrial technology from the University of Texas at Tyler and an MBA certificate from Tulane University. Gibbons can be contacted at robert.gibbons@stagecompletions.com.

Brian Schmidt is a seasoned librarian and industry analyst based in Davis, California, with more than a decade of experience supporting information needs in diverse settings. Since 2011, he has served as librarian and industry analyst for Geothermal Rising. Previously, Brian served in a variety of library and research related roles, including reference librarian and archivist. He is one of the authors of the 2021 US Geothermal Power Production and District Heating Market Report as well as the follow up report, which is currently in development. He earned a BA in psychology from the University of California, Berkeley, an MA in philosophy and religion from the California Institute of Integral Studies, and an MLIS from the University of Wisconsin-Milwaukee.



Anine Pedersen is currently the director of science and external affairs at Geothermal Rising. Prior to this, Anine held positions as a senior exploration geologist at Criterion Energy Partners, as well as a team lead and geographic information systems technician while contracted to Apple Inc. Pedersen also has extensive experience as a geologist at Anadarko Petroleum Corporation, where she worked on various exploration projects in eastern Canada, West Africa, and East Africa. Pedersen's academic background includes a BS in geology and Earth science and an MS in geosciences from The University of Texas at Austin.

Out of the West: Geothermal Opportunities Expand Beyond Historical Boundaries

Brian Schmidt and **Anine Pedersen,** Geothermal Rising

Until relatively recently, harnessing geothermal energy in the US to meet power production and heating needs has been largely restricted to the western states.

The first geothermal production wells in this country were drilled in The Geysers, California, and much of the development since that time has similarly taken place in the west. **As of 2021, the states of California and Nevada (combined) accounted for 85% of the country's geothermal power plants and 93% of the installed capacity, with no geothermal plants being located any further east than New Mexico**.

The reason for this is that exploiting geothermal energy in the conventional manner requires a very specific setting. Heat, fluid, and rock permeability must all be in abundance to utilize the Earth's thermal energy. The western states' geologic setting to the Pacific Ring of Fire results in several such locations.

However, advances in technology are opening opportunities in other parts of the country as well. Technological developments impacting geothermal include enhanced/engineered geothermal systems (EGS), closed-loop or advanced geothermal systems (AGS), and thermal energy networks (TENs).

Enhanced Geothermal Systems

EGS aren't a new concept. The belief that areas with sufficient heat and moisture but lacking appropriate permeability could be engineered into viable geothermal reservoirs has been discussed for years, but recent developments are making this a reality.

In 2023, Fervo Energy **announced a milestone in EGS development** when a 30-day well test at their Project Red commercial pilot site demonstrated a flow rate of 63 L/sec at high temperature that enables 3.5 MW of electric production, setting records for both flow and output from an EGS.

The well test circulated fluid through the doublet system by pumping fluid down an injection well, through a fractured reservoir system, and up a production well. The injection pump located on the well pad provided all the pressure to drive fluid through the system with no need for a downhole pump or artificial lift system.

Sage Geosystems Inc. recently announced that it will partner with San Miguel Electric Cooperative Inc. to **build the first geopressured geothermal system**. The 3-MW EarthStore system will utilize the Earth's natural capacity for energy storage to produce dispatchable electricity on demand. Sage will operate as a merchant, buying electricity when production is plentiful, then storing it and selling back to the grid during periods of shortage. The facility, located in Christine, Texas, will use Sage's proprietary technology to store energy, with a target storage duration of from 6 to 10 hours.

Utah's Frontier Observatory for Research in Geothermal Energy (FORGE) is an international field laboratory dedicated to developing and testing the methods and techniques required to create, sustain, and monitor enhanced geothermal systems resources. It is managed by the Energy & Geoscience Institute at The University of Utah and funded by the US Department of Energy. The project recently achieved a major breakthrough for the industry when **circulation tests proved fluid flow and energy transfer from an EGS reservoir in hot, dry granite**.

Advanced Geothermal Systems

AGS are closed-loop systems that don't require a constant source of water. These systems circulate a manmade fluid through a sealed piping system to absorb through conduction and transport the heated fluid to the surface. After driving a turbine to produce power, the cooled liquid is cycled through the closed-loop piping system to be reheated. There is no direct interaction between the subsurface environment and the liquid in the pipes.

One company helping advance this approach is Canadian-based Eavor, whose Eavor-Loop technology utilizes a closed system that circulates a proprietary working fluid, thus limiting the need for accessibly fluids and rock permeability in the site. In 2023, the company celebrated the **inauguration of their first commercial project** in Geretsried, Germany, which targets 8.2 MW of power by 2026.

AGS are also being used to extend the lifespan and increase the production in existing geothermal wells. GreenFire Energy **recently announced a project** to demonstrate their GreenLoop system at The Geysers geothermal field in northern California. The Geysers was the first geothermal field in the US used to produce electricity and is among the largest developed geothermal fields in the world, but it has experienced a decline in production over the years. GreenFire's closed-loop system uses a downhole tube-in-tube heat exchanger to circulate a variety of working fluids, creating a system that extracts heat rather than water, thereby preserving the resource.

Thermal Energy Networks

While not as geologically limited as conventional geothermal power production, geothermal district heating systems have also traditionally been focused in the western states, **beginning well over a century ago in Boise, Idaho**.

TENs are utility-scale thermal energy infrastructure projects that connect multiple buildings into a shared network involving thermal energy sources such as geothermal boreholes, surface water, and wastewater. They operate at lower temperature differentials compared to traditional district heating systems, giving them a variety of advantages, including lower heat losses, flexible heat sources, energy storage compatibility, and reduced infrastructure costs.

At least 13 states are currently implementing TENs, including East Coast states such as New York, New Jersey, and Massachusetts. Most of these projects are still in the planning or regulatory stage, but construction has already begun in a few places. The first geothermal network pilot project in the US began construction in 2022. Located in Framingham, Massachusetts, the route consists of 36 buildings (24 residential and five commercial) and a total of 125 customer accounts.

Expanding Geothermal Market

The geographic expansion of possible geothermal project locations opens up the possibility of dramatically increased investment in the industry. A 2024 Wood Mackenzie article estimates that though global spending on geothermal pilot projects is currently limited to a few hundred million USD, **it could rise to as much as $1 trillion by 2050** if these next-generation technologies succeed in making geothermal development location-agnostic.

This increased investment is, to some degree, already being seen. At least **six startups have closed significant funding rounds this year**. The focus of these companies varies—from developing new drilling methods to improving well designs to using artificial intelligence (AI) to reduce exploration costs. But the complementary nature of these goals makes the sector as a whole more attractive to potential investors.

In addition to the exploration and development companies, there are also a variety of service, technology, and equipment design companies among the recent geothermal startups. Some of the services offered include **reservoir stimulation**, **HVAC system installation**, and **advanced AI sensing techniques**. Tool and equipment companies have focused on aspects such as **improved drilling technology**, subsurface monitoring tools, and **software development**.

Texas seems to be a nexus of geothermal startups. According to a 2023 report, titled "**The Future of Geothermal in Texas: The Coming Century of Growth & Prosperity in the Lone Star State**," from 2016 to 2022, 11 of the 27 geothermal-related startups in the US were headquartered in Texas. Of the 43 total startups polled for the report, 39% were engaged with AGS technology, 23% were engaged with EGS, and 15% were pursuing either both or hybrid concepts. Only 23% were not involved with either technology. The same poll showed 31% of the startups focused on power production, 23% pursuing direct-use heat applications, and another 23% engaged with both.

Moving Forward (and Eastward)

For the bulk of its history, the geothermal industry in the US has been constrained by its geographic limitations. But new technologies are breaking down these limitations and seem to be creating the right set of circumstances for expansion into the rest of the country, and indeed, the world.

Overcoming the geographic requirements of geothermal production could be game-changing for the industry, as well as the energy sector as a whole. TENs are already bringing geothermal heating and cooling to the Midwest and East Coast, while EGS and AGS technologies point toward the possibility of geothermal power production anywhere.

As states wrestle with how to meet their Renewable Portfolio Standards, geothermal **offers the highest capacity factor among renewable sources, as well as a competitive Levelized Cost of Electricity (LCOE)**. It also offers a small surface land footprint, near-zero emissions, and the flexibility to ramp up or down to help cover changing operational requirements through the day as the output of intermittent renewables varies.

Geothermal power, heating, and cooling coming soon—to a state near you. **JPT**

Are We "Refracturing" or "Recompleting" with Mechanically Isolated Subsequent Stimulations in Organic Shales?

Robert Barba brings more than 4 decades of expertise in the petroleum industry, specializing as an openhole wireline engineer, petrophysicist, product development manager, and completion optimization advisor. His work emphasizes the integration of petrophysics with completion and reservoir engineering to enhance well recovery. With a wealth of knowledge in both conventional and shale reservoirs, Barba earned the 2018 SPE Southwest North America Regional Formation Evaluation Award. As an SPE Distinguished Lecturer (1995–1996), he shared insights on optimizing completion designs through petrophysical and reservoir engineering inputs and was again nominated for the 2024–2025 DL season. A recognized authority on refrac candidate selection and best practices, Barba developed techniques for evaluating well performance that have been used on over 5,000 wells. Recently, he focused on refrac reorientation and parent-child issues facing the unconventional sector, contributing significantly to the field's literature.

Robert Barba, Integrated Energy Services Inc.

Numerous articles and technical papers have shown that perforating and fracture stimulating previously undrained rock in wide-cluster-spaced legacy organic shale wellbores can result in superior economics to new wells in many areas. With advances in mechanical isolation operators can seal off the narrow existing drainage intervals in legacy wells to enable stimulations to focus on "new rock."

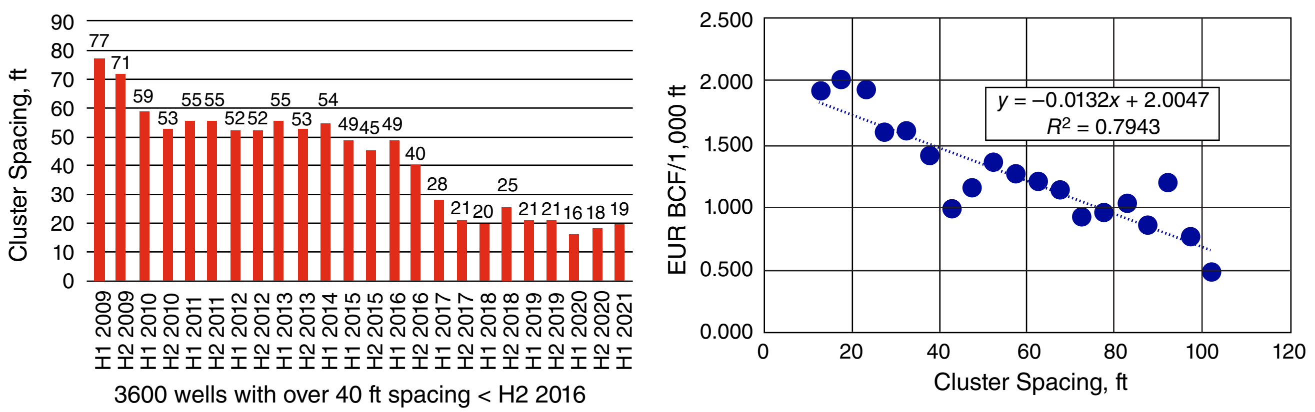
In one reservoir-pressure-monitoring pilot well drilled by ConocoPhillips in 2016 it was observed that 85% of the lateral interval was not being drained where the original completion had 50-ft cluster spacing. The observation well was 70 ft away from the producing parent well.

For wells that have relatively wide well spacings (over 600 ft), the post-stimulation total enhanced ultimate recovery (EUR) can be from three to four times the original EUR.

The two most active operators doing these types of stimulations in the Eagle Ford Shale (ConocoPhillips and Devon) are primarily doing protective treatments in parent wells to avoid significant child well EUR losses from asymmetric fractures.

In URTeC 3724057, Barba et al. demonstrated that when parent wells are restimulated following mechanical isolation the combined NPV10 of the post-stimulation production from the parent and the EUR preservation from the children is significantly higher than a new well's NPV10.

The first-order child wells will have asymmetric fracs running home toward the parents and stranding 40% of the reserves on their distal side if a protective refrac is not done on the parent, as was



A comparison of cluster spacing history and EUR/ft history for the Haynesville Shale. Source: Robert Barba.

shown in **SPE 213075**. The second-order child wells have an average of a 20% EUR loss.

Discussions with operators and presentations by upper management concerning this damage indicate that other than a few of the main players doing these subsequent stimulations, not all operators are aware of the detrimental effects of asymmetric fractures.

A major operator presenting at the 2023 SUPER DUG Conference mentioned that they saw positive production increases when Bakken parent wells had fracture-driven interactions (FDIs) from offset child-well fracs. When the author asked the presenter in the Q&A session if they were concerned about the EUR damage from the asymmetric fractures which resulted in these FDIs, he was clearly not aware that it was a problem.

For those who might not fully grasp the nuances of challenging parent-child interactions, consider the situation of parents supporting adult children who have not yet achieved independence. The goal for these parents is to encourage self-reliance and maturity, rather than a return to a dependent lifestyle. In the context of well management, the parent-well protective refrac is also designed to enable child wells to achieve their maximum production potential.

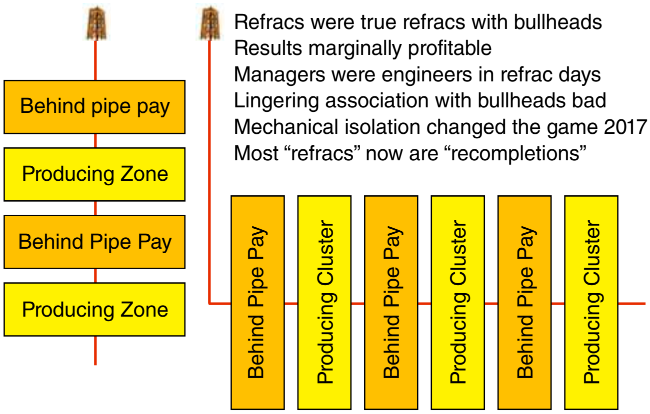
While these protective recompletions in legacy parent wells can provide a significant economic benefit, the treatments have not been accepted by all operators as a tool to significantly grow company asset value. There is little or no activity in areas where all the wells on a pad are legacy parent wells with no nearby children.

One of the larger operators doing these treatments indicated that it had no plans to redevelop any all parent well pads in the near future. A challenge this strategy brings is dealing with the multiple pressure sinks on legacy well-pad wells that would require all wellbores to be mechanically isolated and treated in a zipper pattern.

A four-well pad with P50 post-refrac recovery of 330,000 bbl of oil per well has an expected recovery of 1.32 million bbl of oil for a $11.2 million combined authorization for expenditure (AFE) (Barba 2022). The expected ROI is 3.6 to 1 with a 63% internal rate of return (IRR) and $20 million NPV10.

Do we really have an inventory problem? Or is it that operators do not fully understand the magnitude of the volume of remaining mobile hydrocarbons that are stranded in these wide-spacing legacy wells? There are over 56,000 of these wide-spaced wells in the US at this time.

It is possible that a large part of the hesitation for operators to take refracs mainstream to achieve significant production growth is that we have been mislabeling these mechanically isolated subsequent stimulation treatments?



"Refracs" vs. "Recompletions." Source: Robert Barba.

What is being done is a direct analog to stimulating a previously untreated zone above producing perforations in a vertical well. These treatments are typically called "recompletions" instead of "refracs."

These behind-pipe zones frequently have close-to-virgin reservoir pressures and high producing rates after recompletions since the rock was not previously stimulated in organic shales. A "refrac" re-enters the same fracture and can only effectively recover the remaining reserves from the depleted current producing zones. Any new rock perforations added before the bullhead was pumped would be difficult to frac effectively. There are too many open perforations to implement extreme limited entry, and diverting material must be used. The depleted zones consume large volumes of the treatment until diversion hits the multiple phased perforation clusters.

Since phased perforations all have different stress fields acting on them it may take numerous diverter drops to seal off individual clusters much less raise the bottomhole treating pressures high enough to break down the higher closure stress new perfs.

To further demonstrate the difference between a less-desirable bullhead refrac and a better-performing liner recompletion, two separate studies were done to compare their relative performance. These studies, including URTeC 3855094, suggest that less than 10% of the clusters are producing with a bullhead refrac.

The first study in the Eagle Ford showed that in the same well a bullhead refrac increased the recovery factor by 0.9%. The subsequent liner refrac further increased the recovery factor by 9.1% or 10.1 times. The second study in the Barnett showed that mechanically isolated stages outperformed bullhead diverter stages by over 11.8 times per ft.

All said, it is important to understand the distinction between refracs and recompletions since recompleting virgin zones gets a lot more respect in the industry than refracturing existing perforations. That additional respect goes as far as allowing these previously uncompleted zones in vertical wells to have a PV20 asset value for P1 reserves that is universally recognized by reserve auditors.

Unfortunately, the majority of reserve auditors do not see the direct analogy when the wells turn sideways in organic shales. The only difference is the wellbore orientation yet somehow the logic changes.

With certain caveats, organic shale refracs check all the boxes in the SPE Petroleum Reserves and Resources Definitions (PRMS) for booking behind-pipe P1 reserves. Per the PRMS guidelines, they should have a PV20 discounted bookable P1 reserve value.

As an investor in refrac projects, this fine point is a double-edged sword. Yes, it would be good to get credit for behind-pipe assets that qualify for P1 status under PRMS. On the other hand, right now these assets can typically be purchased for their current PV10 producing value.

The P50 producing rate for pre-2016 Eagle Ford wells is 7 BOPD or approximately $250,000 in P1 PDP producing value. The PV20 of the post-refrac production for a P50 post-refrac recovery is $3.6 million. You do have to be careful what you ask for! On a macro basis if 1% of the Eagle Ford behind-pipe refrac candidates are booked, the total asset value add is $554 million.

Another issue is the lack of readily available data in the public domain on what treatments are refracs. Operators want to derisk their refracs, and the performance of existing refracs in their area is important to that derisking process.

Right now, the reporting process is not working reliably as some operators routinely avoid releasing any details about their refrac activity. There are a large number of wells with production spikes and identical "b" factor post-job declines that do not show any record of a liner being installed. A number of them do not have the second completion listed or have a FracFocus report. This is complicated by the large number of multiwell leases that have commingled production where the production increase from the refrac is seen in all pad wells due to the allocation algorithms used by Enverus or IHS.

The fact that the treatment was a liner recompletion or bullhead refrac could be included as check boxes in the existing FracFocus system. Many operators write on their state completion forms "see FracFocus" and provide only that information to the public. Another benefit of using the FracFocus system is the surveillance by a wide range of people observing our activity.

Keep in mind that the birth of the FracFocus database was the outgrowth of concerns from the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC) to provide transparency to a skeptical public. With the numerous environmental advantages of refracs it may be beneficial to let all consumers of the FracFocus data know they are getting oil and gas from "recycled" wells that would have otherwise been nonproductive or abandoned much sooner without the recompletion.

Refracs also have a much lower carbon footprint than new wells and far fewer supply chain issues. If the metric of carbon generated per barrel for new wells is compared to refracs, the refracs have significantly lower carbon emissions to generate an incremental barrel. The carbon required to initially drill the recompletion candidate well has already been consumed by the plants and trees for quite some time. Lower-cost, lower-carbon footprint per barrel, delayed P&A liabilities, more-sustainable process, lower exposure to supply chain challenges, etc. are all strong benefits from recompletions. This is good news and the FracFocus observers from outside the oil field looking in might respond favorably to operators that are taking steps to responsibly lower their carbon per barrel.

Recompletions are a common sense sustainable lower-carbon option to add to new well drilling and completion programs for the organic shale world. Though, it does appear as Voltaire once said that "common sense is not so common," as recompletions are neither getting the respect nor the capital they deserve.

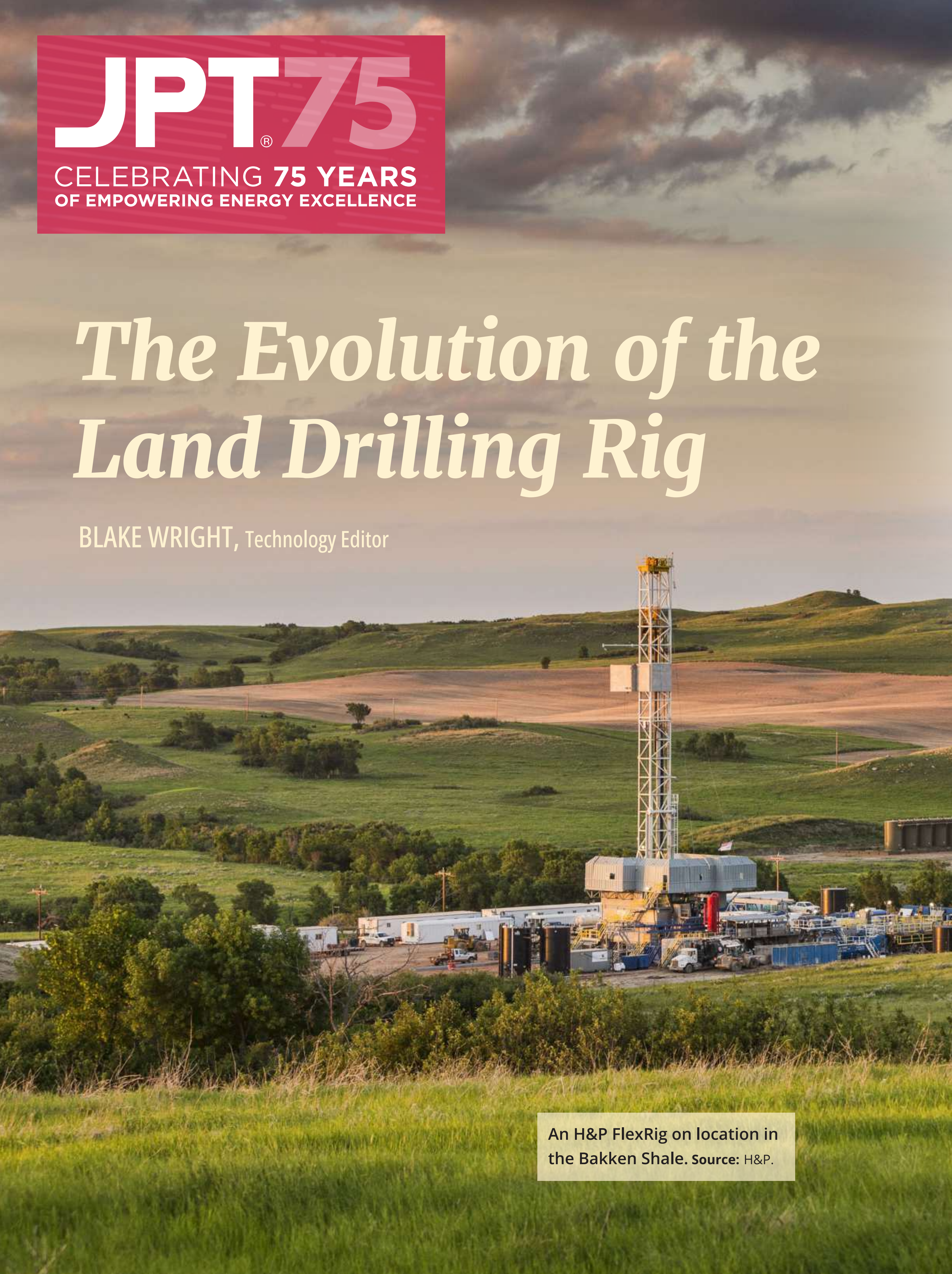
And please, going forward, stop calling them refracs! **JPT**

FOR FURTHER READING

URTeC 3724057 A Comparison of Latest-Generation Frac New Well and Refrac Results with Evidence of Refrac Reorientation *by Robert Barba, Integrated Energy Services Inc; Justin Allison, Armor Energy LLC; Mark Villarreal, Enventure Global Technology.*

URTEC 3855094 Hybrid Expandable Liner System: A Performance-Enhancing, Cost-Effective Alternative to Bullhead Refracturing *by K. Eichinger et al.*

SPE 213075 The High Cost Of Poor Child Protection: Economic Evaluation At The Pad Level With Primary Well Refracs *by R.E. Barba.*



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The Evolution of the Land Drilling Rig

BLAKE WRIGHT, Technology Editor

An H&P FlexRig on location in the Bakken Shale. **Source:** H&P.

The earliest land rigs used materials like bamboo and iron and were powered by animals such as horses or oxen. These rigs used percussive drilling to create the bore, repeatedly raising and dropping heavy iron bits—effective but slow. By the time Edwin Drake was drilling the Titusville well in 1859, steam engines had been introduced to help power now metal pipe down into the Earth's crust. By the 1950s, steam-powered rigs gave way to diesel engines. The 1960s would see the advent of self-elevating rigs—the transition from derricks to mast. During the 1970s, electrical power using on-site generators was introduced to drive systems on the rig, and the advent of new downhole tools would allow drillers to directionally drill while maintaining rotation. In the mid-1980s, the first steerable drilling system was introduced.

Soon, the evolution would move from the drill floor and downhole into the doghouse (driller's cabin). Gone were the mechanical hand brakes and foot pedal systems, replaced by touchscreens and joysticks. The land rig has come a long way.

Hoisting capability and rig-up requirements were key drivers in the design of older units rather than an ability to store materials and move. Older rig-floor configurations were modified to accommodate pipe-handling equipment instead of designed to integrate pipe-handling equipment. These units were not driven by location sizes nor multiwell pad capabilities.

Most of this would change with the coming of the new millennia, and by 2010, it would seem like new innovations would be integrated into land rig design every year—from larger variable skid systems allowing for pad and batch drilling

to app-based automation driving efficiency and safety profile.

Topdrives? Onshore?

Most of what drove innovation in land rigs can be traced back to development in the offshore sector. Much of what would become standard technology on land had its roots offshore, starting with one of the most important technology transfers of the 1990s—topdrives.

"Most of us came out of offshore, and so we didn't have preconceived ideas of what a land rig was," said **Chris Major,** director—global engineering support at Helmerich & Payne (H&P).

"Even before H&P went out and converted aging offshore vessels rigs over to topdrive rigs, I was putting Varco TD-4s or Maritime Hydraulics DDM 650s on offshore rigs. But offshore topdrives were the standard. In fact, if your offshore rig didn't have a topdrive, it couldn't get contracts. Then we started getting into jobs with supermajors internationally, and that became the contractual standard for deep-drilling, international land rigs—the same offshore topdrives on these big land rigs. That got us thinking about the future."

The future had the executives at H&P making some important decisions about the direction of the company. As 2000 approached, word from management was that H&P was going to be a topdrive rig company. Over the next few years, AC topdrives were installed on SCR-style rigs. Before long, the aim was to convert the entire fleet.

"People were kicking and screaming," recalled Major. "A lot of our team didn't want these. Even operators did not want the things. We tried to negotiate a little bit with them, just to see if we could cover the purchase, and eventually, we managed to convince them. But then, our operations folks didn't even want the things. They saw high cost, downtime, learning curves, but we had a leadership that was committed to work through those issues and find solutions."

Everybody questioned the move. At NOV, the prevailing thought in the mid-1990s was that there was no way topdrives would make the migration from sea to land because the land rig structures themselves couldn't take it.

"That's why you saw the big yellow beam up the middle of all the topdrives," said **David Reid,** NOV chief technology officer/chief marketing officer. "We had to take all the load and the torque to the base of the rig. Once we worked that out, because the old Bowen unit—it was an in-line, so the mud line comes through the motor—was this very tight package. It wasn't until we started to think about it, because we were putting them on masts on offshore rigs. Same problem, masts are not good for taking torque. Once it happened, we really didn't think it was going to be as big a deal as it was. I mean, we did a few once we got the smaller Reliance motors, because we weren't running through the main gearbox, which was very much the Varco-IDS type design here. These motors are sitting off the back. But once you got smaller-package induction motors, it really changed everything."

Topdrives brought several efficiencies to land drilling.

First, drilling with "stands" became possible. Stands are multiple joints of connected drillpipe which can be added to the drillstring at once, rather than adding a single pipe at a time.

Traditionally, drilling crews would need to add one joint (one length of pipe) to the drillstring at a time, which was time-consuming. By connecting two or three pipes into a stand beforehand, the rig could add more pipe to the drillstring in a single operation, increasing drilling speed by reducing the frequency of stopping to add pipe.

This advancement enabled the ability to trip back stands and drill using preassembled stands


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Topdrives were used mainly offshore before the 1990s, when onshore applications opened up a new market and a new way of drilling onshore wells. Source: www.nov.com.

built offline. Additionally, drillers could now back-ream to clear and smooth the borehole.

Second was directional drilling—another innovation transfer from offshore. The addition of the topdrive to the land unit made directional drilling possible, which would become increasingly important in the 2000s when the shale boom arrived.

It was around that time that the locomotive industry began adopting AC drive technology in diesel-electric locomotives—an application that led to the birth of the AC drilling rig. Creating a drilling rig with a topdrive integrated into an AC drive system and deployed in a scalable fashion became revolutionary for the drilling industry as well. It wasn't popular at first; however, without it, the industry would be unable to drill today's modern wells.

"I remember being on a plane with our leadership, and my boss at the time was passing around information about some new advances in AC drive technology used on diesel locomotives," recalled Major. "We started looking at this, and what we were thinking about was the idea of a machine that can have 100% torque and zero speed. Suddenly we were like, 'Hey, that sounds like a hoist. That sounds like a drawworks.'"

Added Reid, "We were about 10 years behind trains. All we were doing when we went to DC, we were just picking up traction motors off the train industry. The original thought was that if they're getting rid of these old motors, we can bring them in. The old GE 752 was on everything—your drawworks, your rotary table, your topdrive—and the idea was interchangeability. That was the logic that got them into it. The idea that we can buy secondhand, refurbished motors drove the original topdriver, but no one ever thought those would work on land."

AC Power Opens Things Up

When the AC drilling rig was developed, it was the first purpose-built rig for pad drilling. Pad drilling was a solution for a key operational need: the construction of multiple wells from a single location.

At that time, single wells would be drilled in a row, but pad drilling has not become prevalent. An H&P rig design was engineered and coupled with manufacturing capabilities that resulted in the construction of hundreds of rigs in a relatively short amount of time. This shift in need for pad drilling combined with the new AC rig design ultimately enabled the US shale revolution.

"AC was disruptive," said Major. "We thought about having real block control, where we have precise control. We weren't thinking at that time about drilling apps and some of these other things we've since been exposed to like FinTech or soft torque on SCR type rigs. We were just thinking about having block control and feedback, precise driller control, and an air-conditioned cabin with touchscreens instead of the old brake handle on the rig floor."

While important to the US shale boom, the initial push behind bringing AC rigs to the market was more about a general rethink about what a modern drilling rig should look like rather than by any specific need or application.

H&P would introduce its AC-powered rig design in its Flex3 rig to its FlexRig fleet—a rig no customer was asking the contractor to build. It was more about bringing game-changing technology to the fore rather than satisfying demand. The company took the risk, and the first Flex3 rigs began rolling out of the yard in 2002.

"They were very focused on performance, selling better performance," said Reid. "Everything before that was price. They started to separate out being more expensive and being worth it and then training with crews for safety. They were starting to match where the industry was going. So, after AC, the driller's cabin turns into an arcade game versus a hand brake. It was really the electronic driller, and once again, H&P drove it."

The FlexRig fleets, including the later Flex4s and Flex5s, were wildly successful for H&P in the years that followed, helping the company to grow from just 3% market share in 2001 to approximately 20% market share in US land by the mid-2010s.

Walking the Walk

Introducing walking rigs to a global fleet has contributed to reducing well-cycle times by over 35% from 2016 to 2022. What was once a 3 to 5-hour release-to-spud skid, is now as low as 1½ hours using walking technology. Connected to the power supply from the backyard and increased rotational freedom ensured most walking rigs would never have to power down while transitioning from well to well.

The Helmerich & Payne FlexRig is considered by many to be a milestone in the evolution of the modern land rig. Source: www.helmerichpayne.com.

"If you think about it, we were doing wheeled systems early on in Alaska, and it was because you were just trying to drill and move this massive rig structure that was designed to keep us all warm," said Reid. "We were going to live on these things. They were almost like platforms on land. When you were in cold environments, it was better to walk a rig."

Today's walking rigs use hydraulic "legs" to move up to 500 ft across a drilling location without the need for additional heavy transportation equipment, eliminating the need to assemble and disassemble certain components. The walking legs can also adapt to different terrains, including uneven surfaces and inclines making it difficult to reach more-accessible areas.

The walking "foot" of H&P FlexRig 269.
Source: www.helmerichpayne.com.

Walking packages were developed with several scenarios in mind but were critical in addressing many of the needs of the next generation of unconventional drilling. Walking rigs allowed for wider well-row spacing and placing more rows in a single drilling area.

"What was really controlling the distances we could translate had to do with the slope on the flowline and gravity feedback to the mud systems," explained Major. "So, we started thinking—How do we do walking? How do we use all these tracks? How do we reduce nipple-up times (the duration required to assemble or connect the various components of a drilling rig)? How do we cover most locations?

"We were still dealing with existing wellheads and trying to clear them. You have to deal with that. Then the other thing is, you're on a pad drilling. How do we figure this out as we translate and do pipe-handling over the wells we just were on? Walking it, side-saddling it, and building in wellhead clearances are the most flexible things we can do. Then we started dealing with whether we want to be captive to flowlines. That's why we started on our versions. We've got pump-back systems. We were trying to create a design that could work for nearly any pad drilling location in the US. That's what drove it," Major said.

Tomorrow's Land Rig

Robotics. Artificial intelligence. Autonomous drilling. Much of what the future holds for land drilling centers on the ability of industry to harness and apply new and existing technologies in ways that will once again drive efficiency and safety. There are already robots on rigs that are making pipe connections on Permian Basin wells. In addition to providing consistency and efficiency in drilling tasks, new automated solutions allow for the removal of personnel from red zones on the drill floor.

Another area being looked at is sustainability, which could lead to more hybrid-powered units with energy storage capabilities.

The evolution will continue as the focus shifts from brawn to brains and from task to process. Today's well programs are not one-size-fits-all; they take into account a variety of factors, including company size, geographical location, and specific characteristics such as well spacings, fracture spacings, and optimal pad sizes. New considerations are being added all the time.

Based on the continuing evolution, the future energy landscape will likely necessitate additional ways to transform the modern land drilling rig into the rig of the future. As operators increase their involvement in the energy transition, drilling capabilities must further evolve to drill geothermal wells and explore additional opportunities. **JPT**

FOR FURTHER READING

IPTC 23554 Accelerating Drilling Efficiency and Consistency: A Rig-Based Approach to Exponential Drilling Program Improvements
by C. Major, T. Hall, W. Stogner, and S. Kern, Helmerich & Payne.

What You Need To Know About Automation vs. Autonomy, and the Future of Drilling Tech

TRENT JACOBS, Managing Editor

As the oil and gas industry becomes more familiar with advanced drilling technologies, it also runs the risk of becoming too loose with its language. This word of caution comes from John de Wardt, a recognized leader in drilling systems automation and founder of the consultancy De Wardt and Company, who recently published ***SPE 217754*** *with a team of other subject-matter experts from across the industry.*

In particular, the group of industry colleagues sought to address the overextension of the term autonomous as opposed to automation in reference to various drilling systems and tools.

Presented at last year's SPE/IADC International Drilling Conference, their paper introduces a new taxonomy for autonomous drilling systems, offering a guide to distinguish between automation and true autonomy. It also highlights other critical concepts, including multi-agent artificial intelligence (AI) and the importance of a "system of systems" approach.

In this Q&A, de Wardt explores the paper's goals while offering a candid look at where advanced drilling technologies stand today and where they're headed next.

John de Wardt, *Founder*
De Wardt and Company

JPT: *What motivated the paper's authors to develop a new taxonomy for autonomous drilling systems, what gaps were you aiming to address?*

John de Wardt: I initiated this by presenting at a Drilling Systems Automation Technical Section (DSATS) monthly meeting about the industry's use of the word autonomous. I had seen many articles and company publications claiming to describe autonomous systems, but what they were describing were not, in fact, autonomous. I thought the term was being misused.

The presentation received a positive response, which led to the formation of this group and, ultimately, the development of the paper. It was a significant effort to create a methodology for incorporating autonomy into the levels of automation taxonomy we had previously published for drilling systems automation. And as the paper notes, this is an ongoing effort, but it lays the groundwork for understanding how to assess whether a system in drilling automation is truly autonomous.

JPT: *What led to the problem in the first place, and what, in your view, is the true definition of an autonomous system?*

John de Wardt: People were describing closed loop automation systems that couldn't really stand on their own—they require a lot of human interference. And while the industry is doing a good job of moving up the scale of automation, some described their technology as autonomous, which in the simplest form means it can act on its own without human intervention.

As we developed the paper, we realized that there will always be some human agent involved in drilling. So, the human is not going to disappear completely; the human is going to be interacting with the autonomous system.

I think we have now seen people pull back on the use of the term autonomous and I think they are being much more honest in describing their systems. And don't get me wrong, we are seeing some development of autonomous systems. This is not pushback that we can't do it; this is pushback against misusing the word for marketing purposes.

JPT: *OK, we've touched on this, but let's spell it out: what is the distinction between automation and autonomy?*

John de Wardt: In automation, the human is still supervising the system which is running a prescribed process—the automation loop. An autonomous system can act on its own. If it gets interference into its mission, it can actually change what it's doing in order to accomplish its mission. And the systems that were being described and which prompted the paper were not at that level yet.

JPT: *What are your thoughts on this issue turning into a war of buzzwords, so to speak?*

John de Wardt: I think people find autonomy and autonomous to be attractive words. But autonomy sounds much more sophisticated, and so marketing teams tend to grab onto the term without always checking with their technologists to ensure it's a real application.

The Society of Automotive Engineers (SAE) uses a taxonomy for autonomous vehicles that ranges from zero to level five. However, their model doesn't include cognitive functions—like acquire, assess, decide, and act—which we incorporate in our levels of automation taxonomy.

That makes the SAE model too simplistic for drilling. Autonomous vehicles have access to large amounts of data, and we have sparse data. Vehicles are quite frankly pretty easy to drive, whereas a drilling rig requires a highly skilled, educated operator. It's a completely different environment, and so trying to apply the SAE model to drilling simply doesn't work.

JPT: *Your paper highlights the multi-agent nature of drilling operations, which feels especially relevant with the growing role of AI. Could you explain why understanding multi-agent systems is so important when we talk about autonomous systems?*

John de Wardt: In an automated system, you might be drilling a well with applications controlling various aspects of the operation—applications that come from different companies. These systems need to interact seamlessly in a way that is both safe and hierarchically controlled.

For example, if a kick situation arises, the kick-detection system must override the application overseeing rate of penetration (ROP) optimization. These systems must work together, and when they become autonomous, they need to understand each other's roles and actions within the broader system.

We're now calling this concept a "system of systems."

It's a sophisticated methodology where all the subsystems involved in well construction technically collaborate to deliver a well. An autonomous system within this framework must know how to collaborate—not only with other applications and subsystems but also with human operators.

JPT: *This seems to involve the issue of interoperability, which has been a persistent challenge for automation efforts in the past. Where does the industry currently stand on using a system-of-systems approach?*

John de Wardt: It's early days.

It's a very complex framework to develop, which makes it difficult to implement, and so we've started addressing it in stages. The first mention of it was as part of the Drilling Systems Automation Roadmap, where we introduced the concept. Later, I coauthored a paper with Matt Isbell (Hess Corp.), Moray Laing (Halliburton), and other collaborators that explored the system-of-systems approach in more detail.

Now, I think people are starting to pick up on it. At a recent SPE forum on digitalization of drilling and the well life cycle, participants really grasped the importance of the approach and how it could solve many existing issues. The challenge now is getting enough people to understand what system of systems means and collectively develop industrywide solutions that are both adoptable and practical.

JPT*: *This really underscores the challenge of getting so many parties—multiple software vendors, tool makers, directional drillers, and rig contractors—on the same page. You can't rely on just one company to figure this out, can you?

John de Wardt: That's correct. There was an attempt to create an automated rig, a sort of one-stop-shop, if you will. While significant money went into the initiative, the developers ultimately stepped back. I think that idea has come and gone.

What we're seeing now is drilling contractors stepping forward with automation platforms and software systems—not just for their own rigs but also for competitors' rigs. This space inherently requires multiple players to interact with those platforms to connect all the way through to the control mechanisms on the machinery that execute the operations.

JPT*: *You've mentioned that achieving complete autonomy is difficult in the context of sparse data, and the paper speaks to this as a problem of "observability." Can you elaborate on this?

John de Wardt: Sparse data is a key differentiator when you compare drilling systems to something like autonomous vehicles. Autonomous vehicles have access to an enormous amount of data, so that's not a limiting factor. In drilling, however, it's a challenge.

Sensors are becoming more affordable, which means we're starting to measure data in areas we couldn't before. But even with more sensors, there will still be places where you can't make direct measurements, so models become critical to fill in those gaps.

The question then becomes: Are these models open or controlled by individual companies? If a model is controlled, how reliable is it? For an autonomous system to depend on a model, you need to verify and validate that it's doing what it is supposed to do.

I believe the biggest advancements will likely happen in software programming. Understanding what autonomy truly is, the traits it requires, and programming those traits effectively will be a significant step forward.

From there, progress will occur at the subsystem level within the broader system of systems. If you can map the interactions among subsystems and enable individual subsystems to function autonomously—interacting seamlessly with other subsystems or agents, including humans—then you're advancing autonomy in a meaningful way.

The idea of pressing a single button to make an entire rig autonomous is far off; that's not an immediate goal. The focus should be on achieving autonomy at the subsystem level because that's where the real leverage can happen.

JPT*: *What role does the human in the loop actually play in this scenario? With driverless cars, if you reach full autonomy, there's presumably no need for a steering wheel. But right now, even with Tesla's so-called "full self-driving," you still have a steering wheel for the human to intervene when necessary. So, what does that look like for the human in an autonomous drilling system?

John de Wardt: If you look at autonomous vehicles, even at full autonomy, they still report back to a remote center where someone can intervene. If the vehicle reaches a situation it can't resolve, it goes into what's called safe-mode management and a remote operator can step in, take control, and move it to a point where it can resume autonomy. I think we'll see something similar in drilling—remote centers where humans are ready to intervene when needed.

Another role for humans will likely be supervisory control. We're not going to let autonomous rig systems run completely on their own without oversight. Humans will still monitor operations, ensuring they have the right information displayed to feel confident that everything is functioning properly.

JPT*: *The paper provides actual examples to illustrate what we are talking about here so tell us about that. Where on the rig has autonomy already made significant progress?

John de Wardt: Reservoir navigation was identified as autonomous, and we evaluated it against specific traits to confirm whether it fulfilled them. ROP optimization and cutting load were other processes considered autonomous, but rotary steerable systems were not in the way we looked at it.

However, with reservoir navigation, while it's impressive to say that we're maximizing the interface of the wellbore with the reservoir, there's a potential downside. If I do that but also creating a well that goes up and down—creating sumps—then I am giving my production team problems. Liquids tend to drop out in these sumps, causing slugging as production flow moves through the lateral. Over time, this slugging can escalate, eventually overwhelming the separator and forcing the well to shut in.

The next level of autonomy would need to address this by delivering better wells, not just maximizing reservoir contact.

That means reducing tortuosity, for example, and improving completability. Dogleg severity is often used as a measure, but it's outdated and doesn't accurately represent true well tortuosity, which is critical for completions.

If you have micro-tortuosity, whether known or unknown, in sections where an electrical submersible pump (ESP) is being placed, it can significantly shorten the ESP's lifespan due to sideloading. The real challenge, and opportunity, for the next generation of autonomy is to deliver wells that perform better in measurable terms for all end users, whether that's production capacity, completability, or equipment longevity.

JPT*: *There's been talk for years about automating other parts of the business—e.g., fracturing spreads, artificial lift systems, plunger lift, rod lift—where an AI box essentially takes over for human operators. Do the taxonomy, lessons learned, and stages of automation outlined by DSATS for drilling trickle down and into these other areas as well?

John de Wardt: Absolutely. And it doesn't just trickle out—it flows. The framework works perfectly. We built on concepts from SESAR, an autonomy aviation initiative in Europe that itself drew on Tom Sheridan's* foundational work.

The taxonomy fits seamlessly across the well life cycle—no worries at all there. In the paper, we focused on the drilling process, but we did note areas we hadn't fully discussed—specifically flat-time processes. One of our coauthors brought valuable insights into this, and we included those in the paper. Flat-time processes, like tripping or running casing, are another area where this taxonomy applies and where further work could expand its use. It's not limited to just making hole—it's applicable throughout the operation. **JPT**

Advanced Rig Technology Committee

Those interested in exploring this topic further are encouraged to download the full paper (link below) and register for the SPE/IADC International Drilling Conference and Exhibition in Stavanger this March. The event will feature a DSATS symposium with discussions on how the drilling sector is leveraging advances in AI and an interactive panel session on the evolving role of robotics in the upstream industry. More information and registration details for the conference and symposium can be found here.

FOR FURTHER READING

SPE 217754 Taxonomy Describing Levels of Autonomous Drilling Systems: Incorporating Complexity, Uncertainty, Sparse Data, With Human Interaction *by J.P. de Wardt; E. Cayeux and R. Mihai, NORCE; J. Macpherson, Baker Hughes; P. Annaiyappa, independent consultant; and D. Pirovolou, Weatherford.*

*Tom Sheridan, emeritus professor of mechanical engineering and applied psychology at the Massachusetts Institute of Technology, is recognized as a pioneer in robotics and remote control technology.

True Rig Automation
Stymied by Lack of Interoperable Drilling Tools, but Industry Study Offers a Way Forward

TRENT JACOBS, Managing Editor


Source: Sasacvetkovic33/Getty Images/iStockphoto.

A recent industry study argues that despite 2 decades of progress, the oil and gas industry's drive toward drilling automation is staring at a bottleneck that threatens to stifle future innovation.

Authored by professionals from the Drilling and Wells Interoperability Standards (D-WIS) work group, IADC/SPE 217748 puts the spotlight on systems interoperability—or rather, the lack of it.

The paper brings together expertise from big players such as Noble Drilling, Hess Corp., and Baker Hughes, among others. The group was formed in 2020 under the SPE Drilling Systems Automation Technical Section (DSATS) and its recommendations reflect the input of more than five dozen entities, including most of the supermajors, the big four service companies, the world's largest drilling contractors, and several smaller technology and research groups.

D-WIS points out that the automation tech we've seen hit the market so far has been limited to distinct components and segments of the well-construction process. Notable advancements include automation offerings for pipe handling, rotary steerable systems, and rate of penetration.

Such innovations have taken people out of harm's way, lowered drilling costs, and helped make better wellbores. However, they are standalone, isolated applications that generally do not interact with each other unless they are owned by the same company.

According to the new D-WIS study, reaching the next level of drilling efficiency through a truly automated system requires data to be shared seamlessly between different rig technologies regardless of the manufacturer.

The workgroup's authors assert that not only have the low-hanging fruits been largely picked when it comes to making major gains in well construction but that "the current siloed approach has begun to reach its limits and is consuming capital and resources."

Reasons why interoperability on the rig doesn't already exist range from concerns over the exposure of proprietary information to third parties, to a lack of incentives for equipment makers and service providers to oblige. There's also the age-old tradition of resisting change.

D-WIS is making the case that working past these obstacles will clear the way for a new generation of advisory and drilling process software to be deployed at unprecedented speed and scale. The linchpin for this progress is a common interface standard that will transform disparate technologies into easily integrable plug-and-play components.

To achieve its ambitious goal the industry group has outlined a dual-path strategy that tackles both the technical requirements and commercial risks.

In the near term, the group is encouraging companies to adopt ***ISA-88*, an industrial control standard already relied upon by many heavy industries.** An additional step calls for the development of an Application Programming Interface (API) that facilitates communication between **automated drilling control systems (ADCS)** and external advisory software.

For the long term, the strategy includes drafting a contract addendum to clearly define the risk responsibilities for all parties involved along with the establishment of a dedicated organization to create and oversee the standards.

To expand on these issues and discuss the aims of D-WIS, the study's authors provide additional perspective in this Q&A.

JPT*: *Without interoperability, industry has made remarkable gains in terms of well lengths, rate of penetration, cost reductions, etc. So how big of an issue is interoperability in terms of slowing progress—can the industry keep getting along without it?

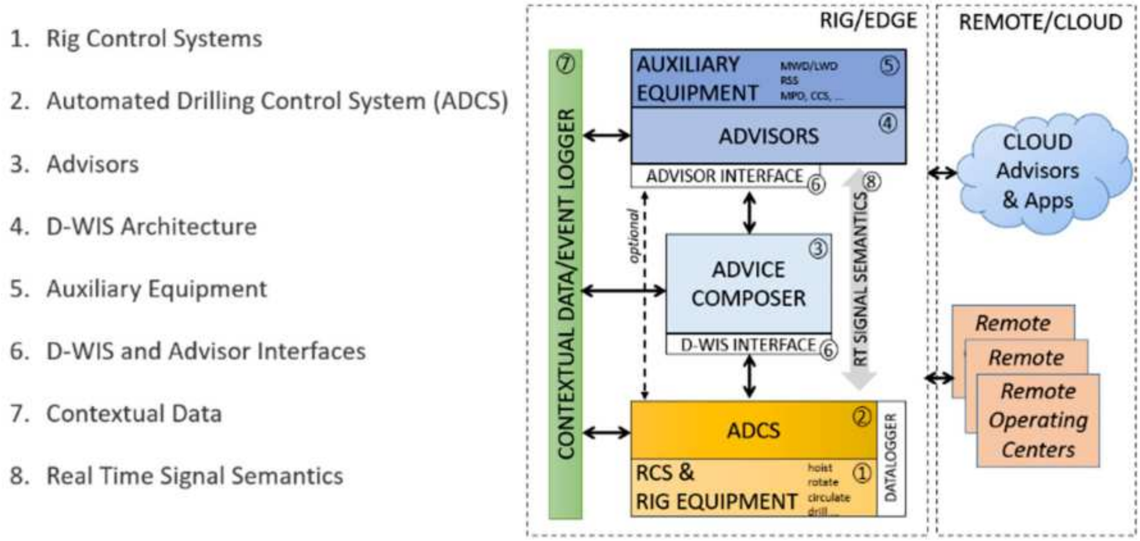
D-WIS: Interoperability allows stakeholders to collaborate at a faster rate and in a scalable manner compared with people-based systems where each person has to be trained and convinced to implement each change.

The industry has achieved the gains referred to above by collaboration with people-based systems to introduce new technology, practices, and know-how. Interoperability allows smaller players to use the infrastructure of the larger players to pursue value.

Once technology is proven, it can be deployed using the scaling ability of the infrastructure. Ultimately, this allows for management of change at a much larger scale. Along the journey, well designs will be improved to provide better well-construction quality and life-of-well performance as more well-construction systems are integrated.

JPT*: *WITS/WITSML standards were created decades ago for data reporting which the paper notes do not meet the information exchange requirements of rig systems automation. Can you break down the distinction and tell us why data communication was solved for but standardizing the data itself has been such a barrier?

D-WIS: It's an interesting question, and it leads to the different types of interoperability that might be useful in well construction. As shown in the high-level D-WIS example architecture



D-WIS Infrastructure architecture. Source: IADC/SPE 217748.

(see above) there are different kinds of data being exchanged between the different system components.

The arrows indicate interfaces where communication occurs with specific protocols. The arrows leading to the Contextual Data/Event Logger might be WITSML objects communicated via the Energistics Transfer Protocol. The arrows between the Advisors, the Advice Composer, and the ADCS might be industrial communication systems and use different protocols to better support critical equipment standards.

So, the idea of interoperability does tend to cascade through all systems, but it can still be flexible about which standards are used between systems.

***JPT**: The paper also points out particular challenges faced by small technology vendors in the industry's late-stage technology-development cycle. How would smaller tech developers benefit from developing tools that are more plug-and-play with those made by their larger competitors and vice versa?*

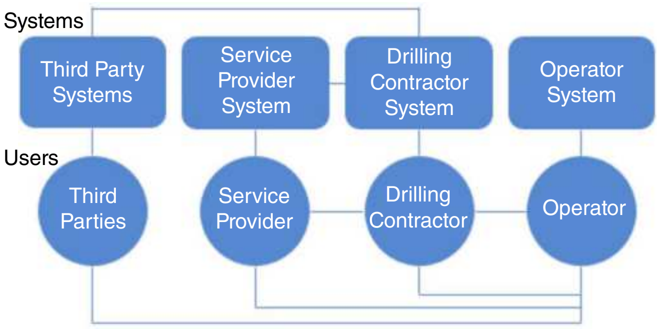
D-WIS: The current industry trend is toward proprietary technology systems that may share the same data inputs, but the data outputs aren't widely shared.

The infrastructure these systems use can be thought of as a network enabling interoperability between systems within the scope of D-WIS. The technology, the part that actually does something, can be thought of as products that function on this infrastructure.

The change we're anticipating is that the infrastructure becomes more interoperable so small and large technology players may leverage it to create and protect value while the data input and output is made available for all stakeholders.

***JPT**: The paper highlights an example from a North American shale well that used wired pipe, a bottomhole assembly, an electronic data recorder—all from different suppliers. The operator acquired valuable learnings yet opted to not use the technology package again. How would have interoperable systems changed this outcome?*

D-WIS: Interoperable systems enable new technologies to be quickly evaluated, improved, or recycled. The traditional proof-of-concept test was mainly limited by the ability of the new technology to integrate into the existing system. It's a form of process control, where working this way means a process must be fully defined to be used. It is interesting to think about the cost



This chart represents the current compartmentalized approach used to operate a typical well-construction process today. This status quo is considered a major limiter of the rate of adoption and development of new technologies seen in the drilling sector.
Source: IADC/SPE 217748.

and benefits of interoperability and how they are realized.

So, in a case like wired pipe, even if the network capability of the system functioned as promised, the value was limited by what could be done with the data and the cost of using the system. If it could plug into more existing systems and provide valuable data, the value is realized and can be further developed much more quickly.

***JPT**: With interoperability comes inevitable concerns over how to protect a firm's "secret sauce." The paper provides the automotive industry as an example of a business that successfully embraced interoperability. Are there others, and what are some of the key lessons to be learned?*

Comparisons to other industries are helpful. The costs and benefits of interoperability in any industry flow in different ways due to business models and scale.

Some easy examples include airlines owning their airplanes while individuals own cars. Most industries have one or more critical components (safety, reliability, efficiency, etc.) that resulted in regulation mandating interoperability. While the benefits can be somewhat foreseen, the value is very difficult to quantify until a system is actually in place. It is also interesting to note that those who pay to create interoperable systems aren't necessarily the ones who get to reap the benefits, as seen in the example of car manufacturers.

***JPT**: You are proposing a standard called ISA-88 as one solution for the drilling sector. Can you summarize the standard and tell us why other industries have adopted it?*

D-WIS: *ISA-88* is the Batch Process Control Standard. It is an international automation standard on how to automate a batch control system. Basically, it uses a set of procedures (recipes), along with some equipment, to deliver an activity in a batch process.

In well construction, we deliver batches of borehole sections, which in aggregate form a well. So, *ISA-88* represents a set of guidelines (structure) around which to automate the drilling process.

However, the drilling process has many unknowns, a significant paucity of measurements, and many individual players. It also involves significant sharing of information (the current state of the system, the attributes of a signal, the capabilities of both ADCS and Advisor Applications, etc.).

With all this in mind, D-WIS is adapting and modifying *ISA-88* to the drilling process.

***JPT**: One of the things needed for all of this to work is an API. Are there any major challenges in building this for automated control systems and/or the contextual data model?*

D-WIS: Some of the challenges with the contextual data model are the definition of a common "rig action plan," or a common digital representation of procedures, and recording of system transactions (a drilling "black box" recorder).

There is still industry work to be done to create a method to work this way.

The contextual data model focuses on data shared by all participants during execution of drilling operations. This is a blend of the rig action plan and real-time operations—there does not currently exist a contextual data model, so the challenge is to develop and test such a model.

***JPT*: The paper describes the above as short term steps—what is needed now to act on these proposals, and how long would it realistically take to complete the steps once work does begin?**

D-WIS: It is a journey. The initial systems comprising an interoperable framework are within a year of delivery.

The D-WIS team is now thinking of how to accelerate industry adoption of the framework. Due to its complexity, it will be a piecemeal approach with problem solving at each step working toward an interoperable vision.

***JPT*: As one of the longer-term goals, you are proposing that much of this work result in new API-recommended best practices—this time it's the American Petroleum Institute we're referring to. What's needed for that to happen?**

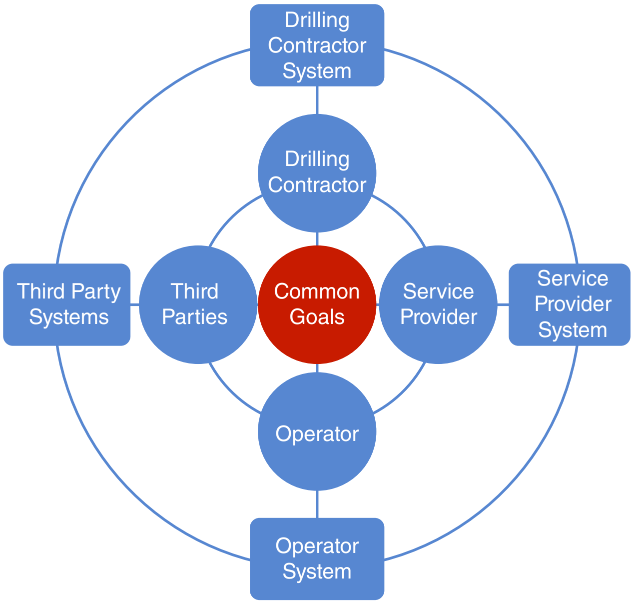
D-WIS: We foresee a body of practice created as the D-WIS system gains traction. Once the body of practice is mature enough, the work to create recommended practices commences.

***JPT*: D-WIS also argues that a new addendum be created for service contracts to support interoperability. Can you talk about what that would do?**

D-WIS: A commercial framework would guide the business discussion of how to use interoperable systems. There are risks to be considered, liabilities arising from unplanned events, and the sharing of value created and protected in a collaborative context.

The goal is to create a set of stakeholders focused on the same well-construction objectives who equitably benefit when the goals are achieved and fairly share limited risk and liability when they aren't.

***JPT*: Another pillar of the long-term vision, D-WIS is proposing an "industry vehicle" to take over the initiative and actually create the interoperable system you're calling for. What would that look like, and why can't D-WIS transform into this entity?**



An illustration of how an interoperable drilling system could be organized to promote collaboration across various parties. Source: IADC/SPE 217748.

D-WIS: As part of SPE DSATS, D-WIS by its nature does not intend on creating standards or commercial systems. However, we have a body of practice we are advocating for industry adoption.

We are also considering how to best implement the concepts and what type of industry vehicle could best carry this effort forward. We plan for D-WIS to continue its focus establishing interoperable systems, but we need partners to actually deliver it to industry. **JPT**

FOR FURTHER READING

IADC/SPE 217748 Interoperability for Drilling Process Automation *by R. Van Kuilenburg, Noble Drilling US Inc.; M. Isbell, Hess Corporation; M. Behounek, Apache Corporation, now independent consultant; J. Macpherson, Baker Hughes; S. Schaefer, Exebenus; T. Fox, Helmerich and Payne; and D. Pirovolou, Weatherford.*

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