Shale Revolution Revisits the Energized Fracture

Trent Jacobs, *JPT* Technology Writer

In the years since George Mitchell's engineers first used the cocktail of water, sand, and a small batch of chemicals called slickwater to crack open the Barnett Shale in north Texas, trillions of gallons of the low-viscosity mixture have been pumped into shale formations all over the United States and Canada. While the resulting shale revolution owes much of its success to the use of slickwater, it has come at a high cost in terms of dollars and increased public scrutiny.

In response, a growing chorus of suppliers, researchers, and service companies are on a mission to get operators working in North American shale plays to re-examine their almost exclusive use of slickwater and consider displacing large volumes of it with carbon dioxide (CO_2) and nitrogen (N_2).

Those in the industry pushing the change say the "energized" fracturing of horizontal wells is a proven technology that stands to improve the economics of completions and the productivity of horizontal oil and gas wells. They point to a growing body of evidence from both Canada and the US that shows energized fractures greatly reduce the amount of water and proppant required to stimulate shale formations, and have the potential to increase recovery rates substantially. Internationally, the technology could help speed up lagging unconventional shale development by alleviating water scarcity issues. Propo-

As an alternative to slickwater, an energized fluid containing carbon dioxide is pumped into a horizontal well during fracturing operations in the Mancos shale play amid the rugged terrain of Grand County, Utah. *Photo courtesy of Ferus.*

nents of the technology offer a variety of reasons why it has not been adopted on a wider scale including perceived cost issues, logistical limitations, supply constraints and, some say, the factory-mode mind-set of many operators that leaves little time to test and evaluate new completion methods.

Fracturing solutions containing these inert gases are called energized fluids or foams and have been used to fracture vertical wells, tight gas, and coalbed methane formations for more than 40 years. In Canada, energized fracturing technology is estimated to be used in more than 40% of horizontal shale well completions. Comparison studies carried out there show that energized completions cost less and resulted in better performing wells than their slickwater counterparts. Despite the positive results seen in Canada, energized fracture treatments represented only 2% of completions in the US last year. "There is no question that there is not as much application of this technology as there could be," said Mukul Sharma, a professor and chair in the petroleum engineering department at the University of Texas at Austin (UT), who has been researching the subject of energized fractures for nearly a decade. "We have seen a clear benefit in many of the Canadian shales using these energized fluids," he said. However, "In the US, it appears to be a chicken and egg issue with suppliers willing to supply the gas, but needing a constant market demand to justify building gas plants."

Baker Hughes is one of the few companies with a full line of energized technologies that can stimulate wells using just a fraction of the proppant required in slickwater systems. One of the oilfield service company's clients recently carried out an energized fracture treatment specifically for its ability to place proppant in some of the hardest sections of the well to effectively stimulate. Baker Hughes is also introducing the technology to other operators in search of alternatives to water- and oil-based solutions.

To help facilitate the creation of a sustainable market, three of the largest industrial gas suppliers in the world are researching and working with shale operators to identify the best applications for energized fractures in the US. One of those companies, Linde, has been working with its oilfield clients for the past 18 months on improving the logistics and selection of energized fluids and foams to their wellsites. So far, the company says its clients are netting the expected benefits. "Here in the US, the operators who have focused on energized components for their programs are saying they are seeing a cost savings," said Robin Watts, oil and gas technology manager at Linde. "And they have seen better productivity results in the 10% range," according to one of its operator clients.

In both Canada and the US, all industrial carbon dioxide is collected from man-made sources, such as this fertilizer plant in Saskatchewan, Alberta where transport trucks load up with the gas before heading out to a wellsite. *Photo courtesy of Ferus.*

A Forgotten Technology

Since the 1970s, energized fracture treatments have been primarily used as a way to fracture underpressured dry gas formations. The turning point came in 1994 when Mitchell Energy abandoned energized foam fractures after experiencing poor results in the Barnett Shale, a brittle and overpressurized formation that demands high volumes of fracturing fluids, and began using slickwater. Even as slickwater use propagated and shale gas development took off, the use of energized fluids was still considered common. But the success in the Barnett and other plays eventually led to a gas glut, and most drilling rigs moved to oil-rich shale plays, where energized solutions had a much shorter track record of success. This transition away from energized solutions coincided with a younger generation of engineers joining the ranks, and since the breakthrough technology that started it all was slickwater, many in the business concluded that the shortest path to success, and the least risky, was to replicate the processes first used by Mitchell Energy. "As the revolution hit and everybody was looking at water, you had a 30-and-under crowd that never knew anything but water existed," said Watts. "Now, those same companies are taking a look back and applying some of the lessons learned using CO_2 and N_2 from decades ago."

The main difference between energized fluids and energized foams is gas content. Energized fluids contain less than 52% of either CO_2 or N_2, while energized foams have gas volumes greater than 52%. In general, most energized foams consist of 65% to 75% gas and high-quality foams contain 95% to 99% gas. Linde delivers both gases to a drillsite by tanker truck in pressurized liquid form. Using conventional fracturing

Parameter	Slick Water	Linear Gel	Pure CO_2	Pure N_2	Foams	LPG
Fracture Creation	✓	✓	✓	✓	✓	✓
Wellbore Hydraulics	✓	✓	✓	✗	~	✓
Proppant Transport	✗	✓	~	✗	✓	✓
Proppant Conductivity	✗	✗	✓	✓	✓	✓
Fluid Recovery	✗	✗	✓	✓	✓	✓
Reservoir Compatibility	~	~	✓	✓	✓	✓
Safety Hazards	✓	✓	~	~	~	✗
Fluid Availability	✓	~	~	~	~	~
Cost	✓	✓	~	~	~	~

✓ good performance ✗ poor performance ~ unknown/field-dependent

This chart shows the desired fracturing fluid properties and their comparative performances. ***Graphic courtesy of University of Texas.***

equipment, liquid CO_2 is pumped downhole by a service company where it has roughly the same density as water and then as it heats up, it transforms into a gas. For N_2, some specialized equipment is required. Trucks using a triplex pumping unit pump the liquid N_2 from storage, warm it up by using a vaporizer, and then pump it downhole in the gaseous state. In most cases, the N_2 must be warmed up from its liquid state, because it is so cold it could damage conventional casing and other equipment.

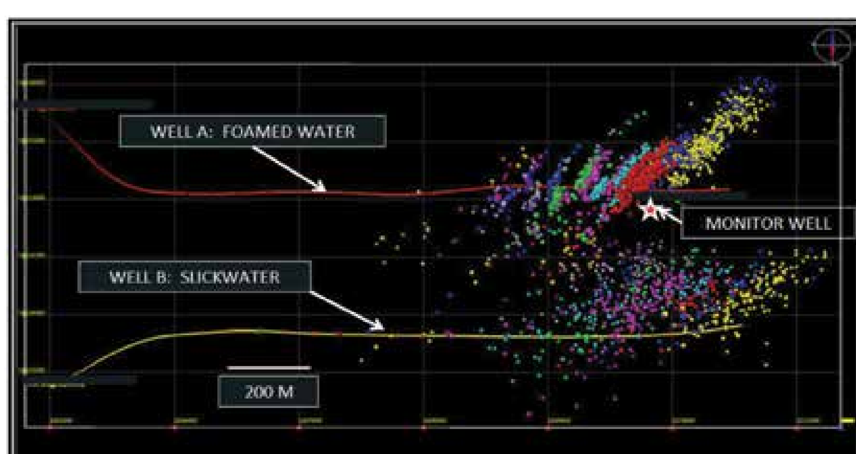
While the potential applications for energized fracture treatments appear to be widespread, reservoir attributes must be considered before selecting CO_2 and N_2. Foam fracturing fluids have most commonly been used for underpressurized wells where the reservoir pressure is too low to drive a column of water out of the well. For those reservoirs, choosing a foam or energized fluid is an easy decision, because otherwise the well is more difficult to clean up prior to the startup of production.

In wells that have asphaltenes and paraffin issues, energized fluids and foams with CO_2 may not be the best solution because of reactions that can occur and damage the formation. In dry gas wells, these problems do not apply and the use of energized fluids and foams have been more accepted. Because of the relatively small number of high-pressure pumps designed for N_2, the gas has seen more use in shallower wells. In deeper formations, such as the Eagle Ford Shale, N_2 requires pumping pressures as high as 15,000 psi.

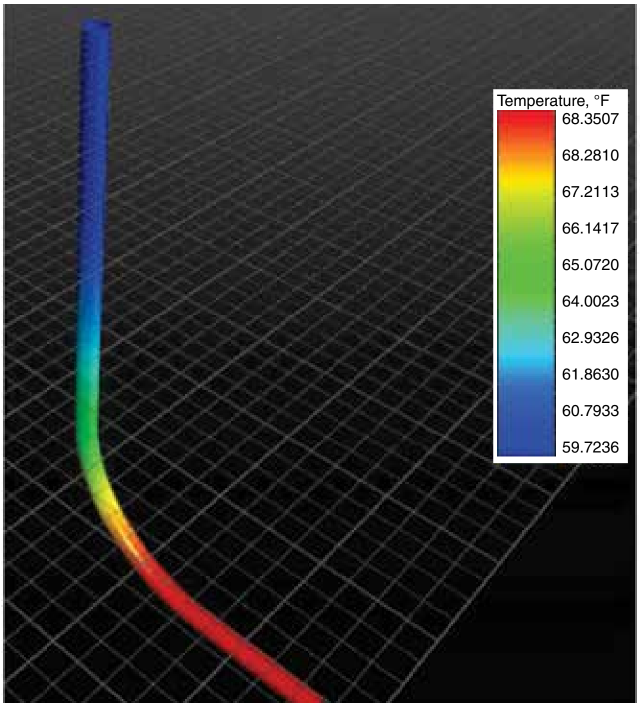
Water Issues a Driver

Many of the boomtowns and surrounding areas that support US shale plays are under threat of drought, so water scarcity has become an issue for the unconventional business. A report published this year by a nonprofit investor group found that more than half of the counties in the US where horizontal wells are being drilled and completed with hydraulic fracturing are facing drought conditions. To reduce water consumption in these areas, some companies have invested millions of dollars in water treatment facilities to recycle the water after flowback and are even tapping into briny and brackish wells instead of freshwater sources. Since only 10% to 20% of fracturing fluids flow back to the surface in most cases, recycling can only displace a small portion of the water used in subsequent completions.

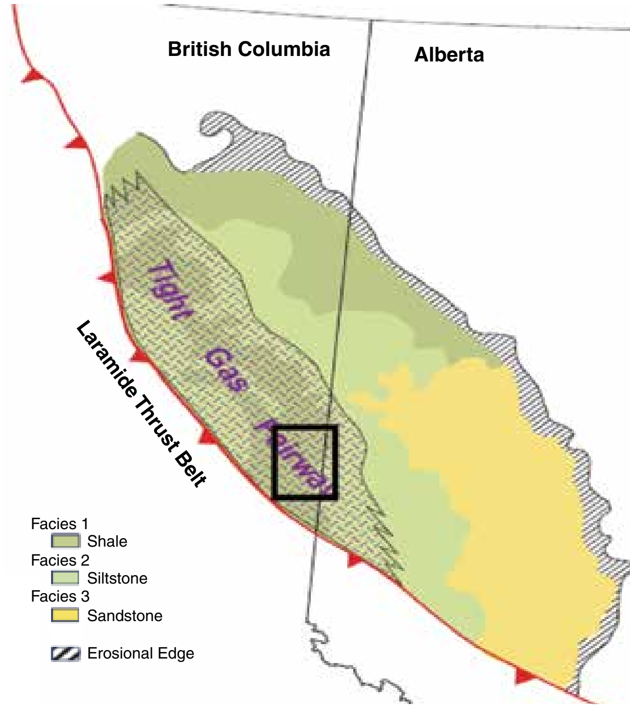
If it is not recycled, the water is pumped into injection or disposal wells. This practice has become a topic of public concern after reports of earthquakes began about 4 years ago in the central US, where disposal wells are heavily used. Research done by the US Geological Survey and universities suggests that the increased injection of wastewater from oil and gas operations near fault zones may be inducing "swarms" of earthquakes, some large enough to cause damage to buildings and homes. In 2011, Arkansas regulators banned the use of disposal wells in part of the state. In California, where earthquakes are common, the thought of inducing even a small one



This chart shows the variation in the microcosmic signature of a slickwater and energized foam treatment in two western Canadian wells in which the same tonnage was pumped downhole to the same number of stages. The data shows the relative uniformity of seismic events with the foamed fracture, compared with the more scattered events in the slickwater fracture. ***Source: Paper SPE 166268.***



The software, ERAC-3D, developed by the University of Texas, combines fracture, wellbore, and well productivity models for energized foams and fluids, as well as all other conventional fluids such as slickwater and gels. *Image courtesy of the University of Texas.*



The Montney play straddling British Columbia and Alberta in Canada is a long producing tight gas formation and was selected for a fracturing fluid comparison study because of the variety of solutions used. *Graphic courtesy of Ferus.*

has become the latest argument against expanding unconventional oil and gas development there.

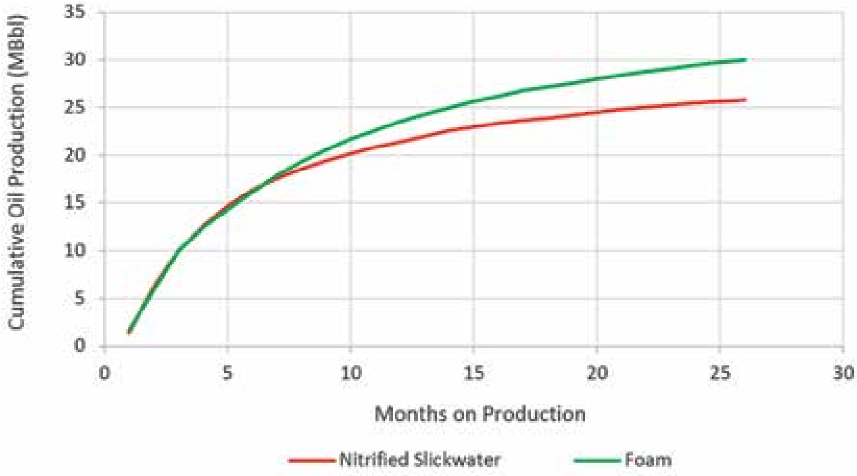
In regard to production problems, the introduction of millions of gallons of water can lead to formation damage in plays prone to clay swelling or water loading. This occurs when water is trapped in a reservoir's nanoscale pores and inhibits the flow of hydrocarbons. Formations that are naturally low in water saturation are especially vulnerable to this effect. According to Sharma, there are only four places the fracturing fluids can go to: the wellbore, the rock matrix, unpropped fractures, or propped fractures. "There is really a question about what is happening to the frac water and how much of an effect it is having on our IPs (initial production) and recoveries," Sharma said at a recent joint industry and university meeting in Austin, Texas. "The fact that we recover only about 20% of the water tells us it is sitting in one of these places." Sharma and his team of research students concluded that one way to minimize water loading is to opt for an energized solution, because the gases do not cause swelling and can even help prevent water from saturating the rock.

As part of the UT-joint industry consortium, which is funded by 34-member operators and service companies, Sharma and his team have developed what they say is the industry's first software capable of modeling energized fluids and foams, as well as conventional fluids such as gels and slickwater. Without this tool, operators would otherwise have little predictive ability when it comes to applying energized fractures. "All of the other hydraulic fracturing (modeling software) in the world are really designed for polymer or water-type fluids, which are assumed to be incompressible and isothermal, so the density and temperature do not change. There is no change in the fluid characteristics as it goes down," Sharma said. The modeling software developed at UT takes into account the changes that energized fluids would undergo as it flows through the wellbore,

MONTNEY STUDY WELLS—AVERAGE COMPLETION COSTS

Fracture Fluid Type	Avg. Completion Cost (USD Millions)	Data Points	% of Difference from Slickwater
Binary (CO_2 + N_2) Foam	3.18	12	–20
CO_2 Foam	2.95	12	–26
N_2 Foam	2.94	7	–26
Slickwater	3.97	4	—
Total		35	

Source: Ferus.



A production curve chart shows the difference in cumulative oil production in the Buck Lake field located in the Cardium formation in western Canada. The slickwater used had a nitrogen content of 12% compared with 58% for the foam treatment. *Graphic courtesy of the University of Texas.*

such as the phase behavior, density, and temperature variations. The software, available only to consortium members, has been in development for more than 8 years and was recently updated to feature a 3D user interface so engineers can visualize their well designs before choosing a fracturing fluid.

The Canadian Experience

Straddling the border between the Canadian provinces of British Columbia and Alberta is a long producing tight gas formation called the Montney shale. Production from the maturing Montney was revived in 2005 when companies began horizontal drilling programs in the area. Early on, operators were using hydrocarbon-based gels for fracturing, but in search of cheaper alternatives, more wells were fractured using energized fluids and foams. Then over the past 3 to 4 years, larger operators in the area, including Encana and Shell, switched from energized solutions to slickwater as a cost-cutting measure. The variety of fracturing fluids used in wells located in relative proximity is why industrial gas supplier, Ferus, selected the Montney to carry out a comparison study using publicly available completion and production data. "It was a good opportunity to go in there and do a rate transient analyses study to see which systems were most effective," said Murray Reynolds, director of technical services at Ferus and author of the SPE technical paper that outlined the study. "We looked at cost, we looked at NPV (net present value), and we looked at water savings."

After analyzing the cost and completion methods used in 50 multistage horizontal dry gas wells that had been producing for more than 18 months, the study concluded that energized foam completions were about 25% cheaper than slickwater completions and used about 80% less water. The average completion cost for a slickwater completion in the area was USD 3.97 million, compared with about USD 2.9 million for a N_2 or CO_2 foam completion. Some of the added cost for the water-based treatments included water sourcing costs, and having to haul flowback fluids to disposal wells located more than 90 miles away. "As activity picks up, sourcing the water becomes more challenging for operators," Reynolds said. "But it also means that finding a place to dump the water is becoming increasingly difficult."

The study says that wells completed with an energized fracture were able to produce earlier because CO_2 and N_2 flow up the well freely on their own in the cleanup phase. The energized wells also achieved higher recovery rates of gas over the slickwater wells, on average equal to USD 3 million per well. By volume, the energized fractures were 25% smaller and required 30% less proppant than slickwater-induced fractures, but produced more gas. "The proppant that is pumped is obviously placed in a position that is more effective," Reynolds explained.

UT also compared data from horizontal wells in Canada and found similar results to the Ferus study. The university examined the completion methods and production results from three separate fields in the Cardium area in western Canada, and concluded that in most cases, the wells with energized fractures had the highest production rates and projected cumulative production curves.

Operators in Canada are able to use CO_2 and N_2 in such a large proportion of their horizontal well completions because the technology is familiar to many service company crews in the region, the required equipment is readily available, and there is a strong supply network. Ferus reports that the demand for energized fracture treatments is increasing in Canada, but the US market is just now opening up. Because of supply limitations, Reynolds expects a slow uptake over the next 10 years for energized fracture treatments in the US compared with what has happened north of its borders. "If everyone in the Eagle Ford said tomorrow, 'I want to switch to CO_2 foam-based fracs,' it is just not going to happen," he said. "It will not be overnight, but I think it will happen."

Limited Use in the US

The highest proportion of energized fracture treatments in the US is in the San Juan basin that spans northwestern New Mexico and the southwestern corner of Colorado. Driven by water availability and sensitivity to its use, around a quarter of completions in the San Juan basin used an energized component in the first half of last year, compared with approximately 3% in the Marcellus Shale, according to Houston-based market intelligence firm PacWest. In many other plays, including the prolific Eagle Ford Shale, energized fractures account for less than 1% of completions.

Baker Hughes has carried out energized fracturing treatments in both the Marcellus and Eagle Ford and says its experience with energized fluids and foams in the US has so far been positive, in terms of cost savings and production results, but that operators are still in the early stages of determining how to use them. In the Marcellus, Baker Hughes has conducted completions using both slickwater and energized treatments in the same well. After an operator experienced difficulty stimulating the end of its long horizontal wells, known as the toe, it elected to try an energized solution. Satya Gupta, a business development director at Baker Hughes and an SPE Distinguished Lecturer on energized fractures, said the operator applied an energized treatment in the toe section and slickwater in the remaining stages. The operation was done with Baker Hughes' VaporFrac technology, which uses a solution containing up to 95% gas. "The high-quality foams have better proppant transport than slickwater so you can stimulate (toe) sections very successfully," Gupta said.

For the VaporFrac system, which uses very little water, an ultra-lightweight proppant is required because there are not enough liquids to carry heavy concentrations into the formation. In an energized fracture treatment, the amount of proppant required is proportional to the amount of liquid in the mix. Because the VaporFrac system uses high-quality CO_2 foam, it reduces the amount of proppant required for a horizontal well by as much as 90%. At an off-site facility, the proppant is mixed into a viscoelastic gel and is then delivered by truck. "So if you have a location, which has a very small footprint, you don't need a blender or a lot of equipment," Gupta said. "You just add gas to this preslurried gel, which already contains the proppant, and do a VaporFrac."

In the Eagle Ford Shale, Baker Hughes is working on a pilot project with an operator that is seeking to increase production and reduce its dependency on hydrocarbon-based fracturing oils that it is using to replace water, but has found it to be an expensive alternative. The company has also applied the technology in wells with low natural pressure and formations that are prone to water trapping due to low water saturation. Despite its success in the field, Baker Hughes has found that the economics and logistics do not always favor the use of energized fractures. Gupta said that when supply and demand for energized fluids sync up, it is a cost-effective solution, but one that is only now being considered by many operators. "The technologies have been proven," he said. "The reason they have not taken off yet, is that water is still available—and it is cheap."

A tanker truck carrying carbon dioxide makes its way down an icy mountain road in Carbon County, Utah, underscoring some of the logistical challenges involved in high-volume fracturing of horizontal wells in the more remote areas of the US. *Photo courtesy of Ferus.*

Lack of Logistics

Gas suppliers acknowledge that the supply network in the US for energized fluids and foams is not sufficent enough to support large horizontal programs in all areas. Linde realized this firsthand when it and another supplier were involved in a program in the US Rocky Mountains. Partly driven by the high cost of transporting water back and forth over mountainous terrain, the operator selected an energized solution but ran into some logistical challenges. "It took six CO_2 plants to supply what I would call their modest well program," Watts said. "And they were 8 to 10 stage wells, not the massive horizontals like you have in the Eagle Ford or Bakken."

As it stands, Linde's current supply infrastructure is only suited to support pilot projects and not large-scale commercial developments. Part of the reason is that the vast majority of the CO_2 used in fracturing is sourced from industrial plants that can shut down for repairs at a moment's notice, and in some cases, for weeks at a time. On the other hand, N_2 can be produced directly from the air using separation units. Air Liquide says that large jobs have been supplied over the course of a few days with up to 3,500 tons of N_2 for multistage horizontal fracs. Still others maintain that more N_2 generators are needed to increase the supply to the volumes required for horizontal campaigns. Linde says it is looking for operators to commit to energized completions by way of successful pilot programs. Only then, the company says, will more investments be made to expand the supply side of the business.

Long-Term Goal: CO_2 Recycling

To enhance the economic viability of using CO_2 for fracturing, General Electric and Statoil have teamed up to evaluate whether a recapturing system can be used to recycle the gas after it has been used in a well. The industry currently lacks the technology to capture the CO_2 in the flowback phase and reuse it in another horizontal well. Without such a system, the CO_2 is vented into the atmosphere, increasing both the carbon footprint of an energized fracture operation and its costs. At the recent SPE Symposium on Improved Oil Recovery in Tulsa, Oklahoma, Michael Ming, general manager of GE's global research oil and gas technology center, said that the project is in its infancy and could not give a timeline for the development of such a system. "It is not a system that comes together tomorrow," Ming said. "Some of the pieces may come together faster, but as a system it takes some time."

The project is being funded under GE's "ecoimagination" initiative that calls for the investment of USD 10 billion in clean technology research by 2020. Working with Statoil, GE plans to use its suite of other technologies to design a system that could reuse high-quality CO_2 in multiple horizontal wells. The research project is also taking a look at developing a small-scale CO_2 generator for remote locations.

Sticker Shock

Like its competitors in the industrial gas market, Air Liquide is also carrying out research and studying the problem of how to create a larger market for energized fluids and foams. One issue the company and its peers are facing is the impression that water is cheap and energized fluids and foams are expensive. Depending on the variables involved, it can go either way, according to Dave Wedel, commercial manager of Air Liquide's oil and gas business in the US. "Compared to water, a container of CO_2 looks expensive, so there can be a perceived cost issue," he said, adding that because increased production by way of an energized solution is an assumed benefit, it is not always the most convincing argument. Wedel argues that the long-term productivity of the well must be taken into account in order for the benefits of energized fluids to be apparent.

Another barrier to the adoption of energized solutions in the US is the fast pace at which drilling and completing is occurring in shale basins. Over the past few years, operators have been working hard to offset the high cost of unconventional drilling and completion by implementing what many companies now call factory-mode drilling. Rather than approach each shale well with nuanced decision making, many operators have tasked their engineers with planning entire well programs in advance to save on time, materials, and the manpower required to complete dozens of wells as soon as possible. This means that some considerations are not as important as staying on schedule. "If a company is trying to drill 10 wells and if they go with an energized fluid and can only drill 7 or 8, their goal is to drill those 10 and they might accept lower productivity per well in order to meet their schedule," Wedel said.

Production Benefits Debated

One of the main arguments in support of using energized fractures is that while in some cases fluids and foams may cost more than slickwater, they can produce significantly more oil or gas. However, Fernando Covas, oil and gas consultant at PacWest, said some of his clients are still not fully convinced of this. "If there really is a production benefit, that would certainly outweigh any additional cost of the N_2 or CO_2," he said. "But there are so many reasons why you may have higher production; it is a very big undertaking. No one has really been able to isolate those variables to come to a very clear perspective."

In some cases, Covas said operators are reporting no difference in production when using energized fluids and foams compared with slickwater or crosslinked gels. Others say it has made a positive difference in production. Covas attributes the divergence in opinion in part to the short time for which engineers can observe production data from wells completed with energized solutions in the US. Operators interested in energized fractures are trying to carry out studies that eliminate other variables, such as the amount of proppant used, to verify that energized fluids and foams offer better results. "There are people out there trying to do this analysis," Covas said, "but if you talk to different completion engineers, you will get different answers." **JPT**

For Further Reading

SPE 159812 A New 3D Compositional Model for Hydraulic Fracturing with Energized Fluids *by Lionel Ribeiro and Mukul Sharma, University of Texas at Austin.*

SPE 163867 Fluid Selection for Energized Fracture Treatments *by Lionel Ribeiro and Mukul Sharma, University of Texas at Austin.*

SPE 166113 A Day in the Life of a Barrel of Water: Evaluating Total Life Cycle Costs of Hydraulic Fracturing Fluids *by Robin Watts, Linde.*

SPE 168632 A Comparison of the Effectiveness of Various Fracture Fluid Systems Used in Multistage Fractured Horizontal Wells: Montney Formation, Unconventional Gas *by Murray Reynolds, Ferus, et al.*

SPE 168645 Analysis of US Hydraulic Fracturing Fluid System and Proppant Trends *by Purav Patel, PacWest Consulting Partners, et al.*