

Surviving the Renaissance

As horizontal wells mature in the U.S., operators will need to determine the best forms of artificial lift for maximum production.

By Hart Energy Staff

The unprecedented growth of the hydraulic fracturing industry in the U.S. has led to an energy renaissance for the country. But as the predominantly horizontal wells begin to mature, one basic concern arises: how to continue producing the wells to their fullest extent.

To answer this call, there are several forms of artificial lift that have proven successful in unconventional plays, and depending on the type of hydrocarbon being produced, there are numerous recommendations for optimizing the well's lifespan.

"Right now we have identified more than 17 different kinds of artificial lift systems used for producing gas wells and quite a few for producing oil wells, too," said Cleon Dunham, director of the Artificial Lift R&D Council. "The types of artificial lift that are used are a function of many factors including the size of the hole, what size your casing is, what size your tubing is, what your wellbore trajectory is, what experience people have in that area and what support services are available."

Whether producing gas, oil or condensate, artificial lift is used to increase pressure within the reservoir and assist the hydrocarbons to the surface. While there are several varieties of lift available, there are seven basic types from which all others are derived:

- Electric submersible pumps (ESPs);
- Sucker-rod lift;
- Plunger lift;
- Gas lift;
- Chemical lift;
- Progressive cavity pumps (PCPs); and
- Hydraulic pumping systems.

ESPs

Traditionally, ESPs have been brought in to enhance oil production as soon as it begins to decline and while there is still a moderate to high volume of fluid that can be lifted from the well. This fluid could be crude oil or brine, or it can be another form of liquid or gas such as disposal injection fluids, liquid petroleum products, CO₂ or H₂S gases, and even certain solids or contaminants.

An ESP comprises a multistaged centrifugal pump, a three-phase induction motor, a seal-chamber section, a power cable and surface controls. These components hang in tubing that runs beneath the low-profile surface pump, which also makes this a more aesthetic choice of lift, and they attach to the motor, which most often is deposited at the end of the vertical section of the well. When turned on, impellers along the ESP's shaft will spin and force the fluid in the wellbore to rise to the surface.

Standard ESPs can produce anywhere from about 150 bbl/d to 30,000 bbl/d or possibly more if they are equipped with a variable-speed controller that can help extend the range higher or lower as needed. This makes them ideal for wells with low API gravity fluids, a low gas-oil ratio (GOR) or a high water cut.

"The advantage of ESP is you've got an electrical cable that's going downhole to run the lift motor. You can use that cable to transmit signals from instrumentation placed at the bottom of the well that will measure the pump intake pressures, the

intake temperature, the motor-winding temperature, the unit vibration and a few other things,” Dunham said. “That information can be used to not only monitor the well but to see if there are problems and to control them before they become real issues and interrupt production.”

This capability has made ESP a cost-effective option for many operators, said Bill Vaught, director of global business development and marketing for the Baker Hughes Artificial Lift Services group. ESP is one of the primary forms of artificial lift offered by the company. However, he said there are a few things to watch out for in unconventional onshore wells.

“As you draw the well down you find that the well typically has a high amount of gas, and so the ability to either avoid that gas or handle that gas or compress the gas in the well is something we’ve been working on quite heavily; it’s a challenge in some of these unconventional wells,” he said. “The other challenge we’re faced with is getting the system through the bend. An ESP can be a very long system, and if you don’t have the proper equipment for setting that up through a very tight bend, you can damage it going into the well.”

Repairing a damaged ESP system can be very costly, said Greg Nutter, vice president of operations and HSEQ for AccessESP. In some cases, such as when the rig is located offshore or when there are permitting issues or issues with rig availability or accessibility, a rigless ESP offers a more cost-efficient solution.

“If you have to change your ESP every six months and bring a rig out there in an offshore location, it could be a \$5 million proposition just to change out the ESP,” he said. “The whole time it’s not working, you’re also not making produc-

tion, so every day you have zero on your production, it is costing \$100,000 to \$1 million a day. Then you are going to have to spend that \$5 million to \$10 million in operating expenses to call out a rig and get the ESP pulled out of the ground and get a new pump back in the ground. With rigless ESP, instead of waiting up to six months to do this, it can be replaced in a few weeks—sometimes in as little as one week.”

After its initial installation, rigless ESP can be deployed with a slickline, wireline or coiled tubing unit, he said, which might be easier to mobilize depending on the location of the well.

Sucker-rod lift

The pump jack, the horsehead beam and crank assemblies rocking back and forth to produce the energy needed to operate sucker-rod artificial lift systems are common sights in the oil patch. Sucker-rod lift is one of the oldest forms of artificial lift in the world, known for its ability to aid in reducing bottomhole pressures (BHP) to very low levels. In the U.S., about 350,000 wells have sucker-rod pumps. Those wells are primarily onshore because the weight and space requirement of a sucker rod’s surface pumping unit is not practical for offshore rigs.

Sucker-rod pumping systems offer greater flexibility for achieving low-to-medium production rates than other forms of lift such as ESP and hydraulic. The simple design and easy maintenance of the rod-lift components and the fact that this form of lift has been used for several decades, make it less challenging to find people who know how to work the systems. Also, surface and downhole equipment tends to retain its value because of its simplicity in design, which makes it easier to refurbish.

This cutaway shot shows the inner workings of AccessESP’s slickline conveyance solution for rigless ESPs. (Image courtesy of AccessESP)



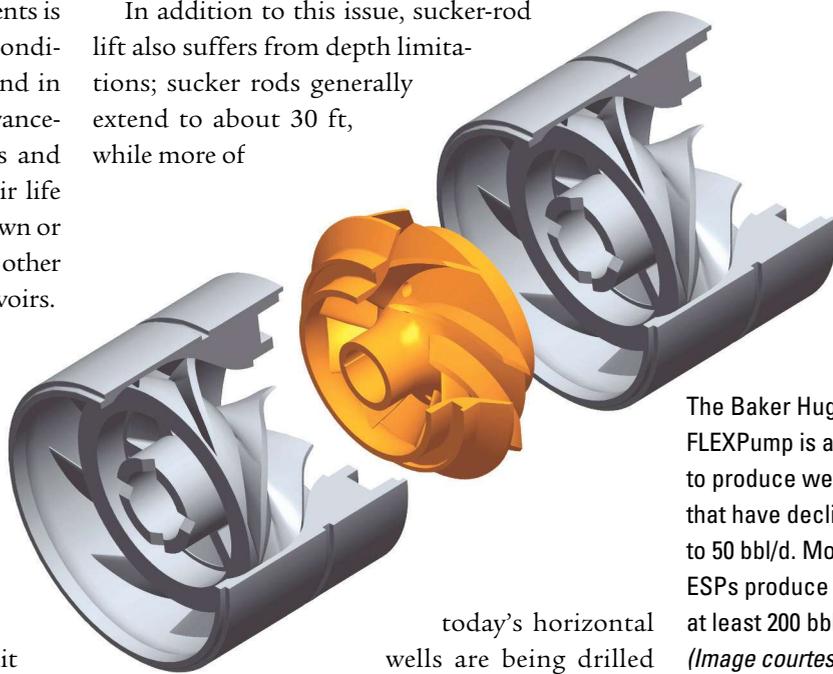
Another benefit to sucker-rod lift components is their resilience to a number of operating conditions such as the HP/HT environments found in many of the horizontal wells in the U.S. Advancements in the metallurgy of the sucker rods and their components are helping to extend their life and reduce the incidence of their breaking down or becoming overly caked with paraffin, scale and other inhibitors common in unconventional reservoirs.

A sucker-rod pumping system comprises a prime mover to power the system, a gear reducer to adjust the speed of the prime mover to the optimal pumping speed, a pumping unit to take the rotating motion of the gear reducer and prime mover and translate it into a reciprocating motion, a sucker-rod string (located inside the production tubing) that transmits the reciprocating motion of the pumping unit to the subsurface pump, and the subsurface pump itself. Other parts exist as well, such as a stuffing box located just above the surface—used with a polished rod to ensure a liquid seal remains consistent at the surface—and of course the beam pumping system that supplies the constant energy needed by the prime mover to keep the sucker rod moving.

Very simply, the surface unit transfers the energy from the prime mover to the sucker-rod string. Then the prime mover, with help from the gear reducer, adjusts the speed so it is suitable for the rotary motion of the sucker rod. The sucker rod has to remain vertical to ensure there is no bearing movement applied to the sucker-rod string above the stuffing box, which in turn ensures the liquid seal remains intact. As the rod turns, the subsurface pump, which is installed as part of the tubing string near the bottom of the well, drives the oil up through the well until it can be collected at the surface.

While this is highly effective in vertical wells, it becomes more of a problem in horizontal wells where it is difficult to place the subsurface pump in a position where it can effectively pump the hydrocarbons around the bend, getting the oil, gas or condensate in the lateral section to move efficiently up through the vertical section to where it can be harnessed at the surface.

In addition to this issue, sucker-rod lift also suffers from depth limitations; sucker rods generally extend to about 30 ft, while more of



The Baker Hughes FLEXPump is able to produce wells that have declined to 50 bbl/d. Most ESPs produce to at least 200 bbl/d. *(Image courtesy of Baker Hughes)*

today's horizontal wells are being drilled deeper than before. However, the relatively new development of long-stroke pumping units has helped to lessen the impact of this particular detractor.

Dunham said other issues that would prevent operators from using sucker-rod artificial lift for their mature wells include too much sand, too-heavy oil or oil that is too viscous, or if the well is producing too much gas. However, he said the pros outweigh the cons.

"I think we have good technology, good automation systems and lots of companies that provide [sucker-rod] equipment and know-how to operate it," Dunham said. "If you have to put a well on an artificial lift system, use sucker-rod pumping unless you can't."

Plunger lift

While sucker-rod pumping is common, plunger lift isn't far behind in popularity. As one of the least expensive and least impactful artificial lift applications on the environment, plunger lift has its own following, said James Bracken, U.S. business unit manager for capillary, plunger and gas well automation at Weatherford.

Of course, there is no set rule stating which type of lift is better than another because it depends on many factors such as the weather and the type of

well and reservoir, he said. However, plunger lift can be used in gas wells, oil wells and gas-lift wells, and it will operate in a similar way across the board, making it easier to find mechanics and other professionals that know how to use it and maintain it.

Plunger lift uses a piston, which is the length of steel also known as the plunger, to pump liquids from the wellbore. The piston travels up and down the well's tubing string at the velocity that best allows it to minimize gas slippage at the pump.

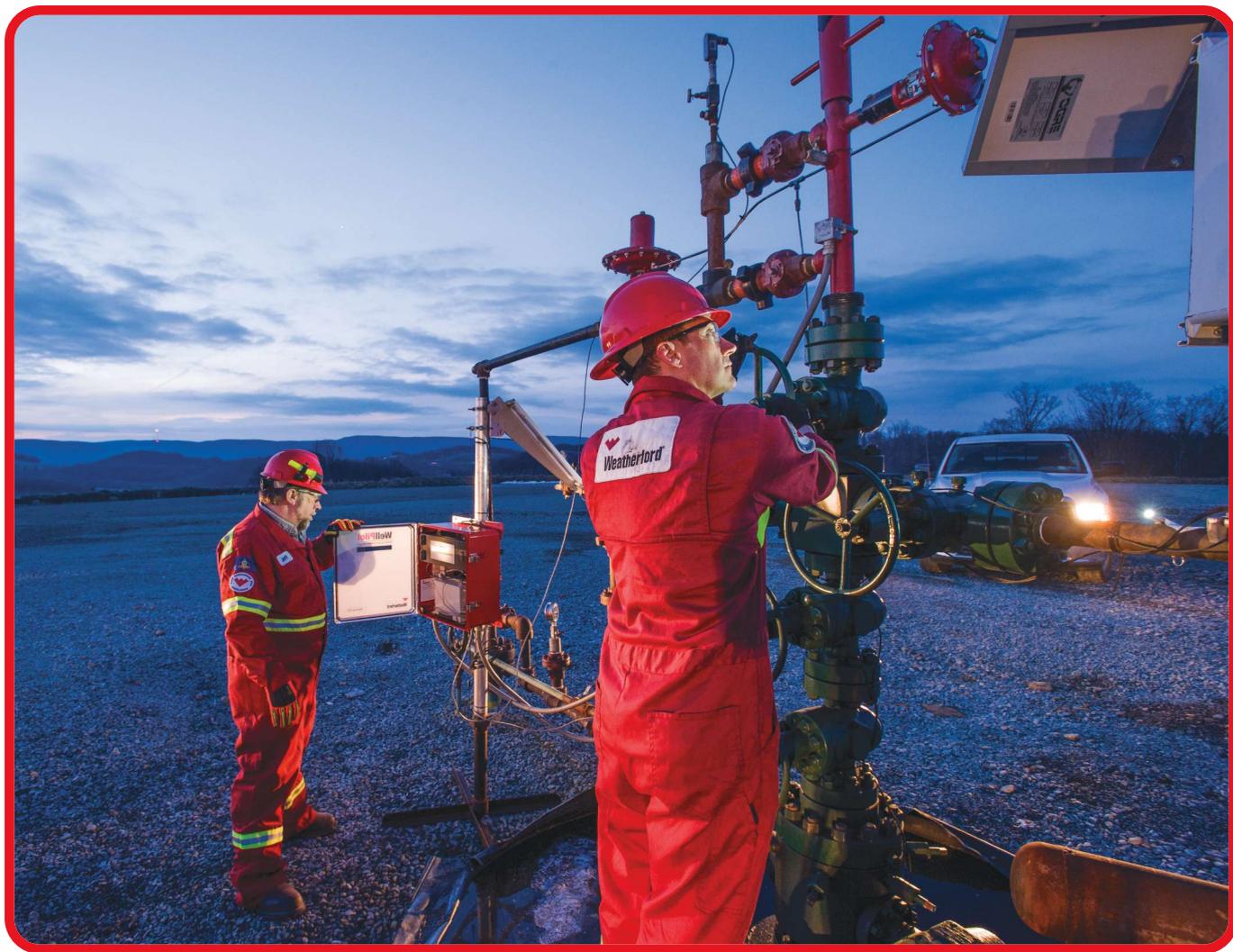
In addition to reducing gas slippage, plunger lift also limits liquid loss and uses the energy created by its piston to more efficiently increase production. It's considered an efficient system because the plunger uses the well's own energy to effectively form a seal—just like a plunger from a hard-

ware store would do—to pull the liquid and the gas to the surface through natural suction.

“When [the plunger] gets to the surface you want to hold it there as long as the gas flow rate stays good,” Dunham said. “When the gas flow rate starts to decline, you drop the plunger to the bottom and then start the cycle again. There are several different kinds of plungers, and there's a difference in cost, a difference in reliability and so forth. The operator has to choose the plunger that makes the most sense for his particular operation.”

One of the trends Bracken said he is seeing at Weatherford is a drive toward more environmentally friendly solutions, which has generated a lot of business for plunger-lift systems. But as Dunham said, not all plunger-lift systems and components are created equal.

A plunger and automation installation is completed in the Northeast. (Image courtesy of Weatherford)



“Mostly you’re going to look at the well geometry—what size casing, what size tubing, the pressures that are associated with it such as bottomhole pressure, static bottomhole pressure, your line pressure at the surface, etc.,” Bracken said. “Your well temperature comes into play because that helps you decide whatever it is you’re going to run; whether it’s a metal geometric cap string or the type of rods or a metallurgical gas valve. Each form of lift operates best within a specific gas or liquid ratio or oil ratio.”

Plunger-lift systems are used on wells that have a high gas or liquid ratio. Dunham said the main drawback of the plunger-lift systems is that they are limited in the amount of gas they can help produce from a well. However, when low line pressures or compression are combined with this form of artificial lift, several types of wells might be produced until the BHP is too low to lift the plunger to the surface.

Gas lift

Gas lift can be one of the most effective forms of lift for getting maximum production out of mature, horizontal wells, Dunham said.

“Gas lift works well in high gas-to-oil or high gas-to-liquid ratios that may be problematic in other forms of lift, such as positive displacement pumps,” said Mark Laine, U.S. business unit manager for gas lift systems at Weatherford. “The general fit for gas lift would be formation gas-to-liquid ratios above 500 standard cubic feet per barrel and liquid rates above 75 barrels per day.”

For this form of artificial lift, high-pressure (HP) gas is injected downhole to reduce the density and viscosity of the well fluids. Bubbles are formed in the liquid by the gas, and they work to help lower the BHP and drive the hydrocarbons up for production.

There are two types of gas lift employed today: continuous and intermittent flow. Continuous flow is the most popular type because it is especially effective in waterflood reservoirs or formations with high GORs. It also is frequently used offshore and on wells with high volume and BHP. As the name implies, this type of gas lift requires the gas to be injected continuously down a conduit. As it mixes with the well’s fluid, the flowing pressure

diminishes and the flowing BHP is reduced below the static BHP, allowing the fluid to flow more easily into the wellbore where the bubbles can then assist it to the top.

Intermittent flow is the periodic displacement of liquid from the well by the injection of HP gas. It is a popular choice when the well has been depleted to its lower rates and even when those low-production rates are hindered by liquid loading.

This form of gas lift is less common in unconventional plays because of the significant presence of sand used as proppant for fracking the shale; the intermittent BHP usually can’t be tolerated by wells that produce sand. It is most commonly used when the flowing BHP is low and when the gas is lifting the hydrocarbons from a bottom valve. Continuous-flow gas produces at a much higher rate, making it the preferred choice among the two whenever possible.

Dunham said the three main objectives of gas-lift oil wells are to inject the gas as deep as possible, to inject it in as stable a manner as possible and to inject it at the optimum rate.

“A lot of people talk about gas optimization, and I say, ‘Don’t talk to me about gas optimization until after you’re deep and stable because until then it doesn’t make sense,’” he said. “So our goal is to design the valves and the spacing and inject the gas at the rate needed to get deep, stable and optimum.”

Using gas lift on a gas well is a different situation all together, Dunham said.

“We’re trying to inject enough gas so that the total gas rate—the produced gas plus the injected gas—is enough to maintain what we call critical velocity, which is the velocity needed to keep the liquid lifted out of the well,” he said. “In gas wells, we like to get the gas injection as deep as possible and sometimes often even below the packer and down across the perforated interval to keep that whole vertical area—or horizontal area as the case may be—swept free of liquid so that the gas can flow most efficiently.”

Chemical lift

Chemical lift also is a popular choice of lift for gas wells, Dunham said.

“There are three main choices for chemical lift,” he said. “They include dropping soap sticks, injecting chemicals in batches down the annulus or using a capillary tube to inject the gas continuously down to the bottom of the well. There are also different strategies for chemical injection, and some people are using chemicals with plungers, chemicals with gas lift and all kinds of different combinations.”

As production declines in a gas field, the drop in BHP will make it difficult to carry liquids to the surface. This is called liquid loading. The creation of more free fluids in a well will produce more backpressure on the formation that could damage it in the long run. Chemical lift is a method used to remove liquids from gas wells when liquid loading begins to occur.

surface. This form of lift requires only one chemical pump, one chemical storage tank and a secondary containment for the chemical tank. It can be used alone or with other forms of lift such as plunger and gas. Foamers also can serve a dual purpose by acting as surfactants for corrosion, scale, paraffin and salt deposition as they lift fluids to the surface.

When a large volume of foamer is injected downhole in a batch it can be left to perform its chemical lift for a time until its performance begins to decline. At that time, another batch can be sent downhole. Foamer also can be pumped continuously downhole in smaller volumes rather than batches. In either case, it’s important for there to be regular monitoring to ensure optimization of this form of lift.

As companies continue to expand into unconventional territories, there will be a call for new and improved technologies in artificial lift.

Soap sticks are an inexpensive means for turning the produced water into a mist that will lift easier to the surface with an up-flowing gas stream. One soap stick can effectively treat 1 bbl of water. Once it is dropped downhole, it encounters the column of produced water where gas bubbles already are churning toward the surface. The stick will dissolve when it encounters this activity. As the mist rises from the chemical reaction of the soap stick, the pressure downhole is likely to be relieved enough to where it can burp up an additional amount of water, usually unloading a total of 1 bbl to 5 bbl of water per soap stick. While this is the least expensive method of artificial lift on the market, it is only able to remove about 50 bbl/d to 100 bbl/d of fluid from a gas well.

Another form of chemical lift involves using foaming agents (foamers) that are lower in density than the liquids in the gas well. As Dunham mentioned, foamers can be applied to a gas well continuously or in batches.

As the foamers are agitated by the gas flow, their bubble film holds the liquids and lifts them to the

PCPs

Use of PCPs is most common in Canada, but because this form of artificial lift is one of the more economical options, its popularity is spreading throughout the U.S. and worldwide.

Similar to a piston pump because of its sealed cavities and its ability to use positive displacement to pump at very low rates, a PCP can work at any deviation angle in a well. This means providing artificial lift for horizontal wells is not a challenge for this pump. What is a challenge, however, is the PCP’s inability to function well in high temperatures; it can only work in a maximum of 350 F. That can be a major issue for many of today’s horizontal wells.

A PCP consists of a helical steel rotor and a stator that comprises metal tubing with internal molded cavities that match the helix shape of the rotor. These cavities usually are made of synthetic or natural rubber, while the rotors typically are made of hardened steel or stainless steel that is covered by chrome plating to make it more resistant to corrosive and abrasive materials. In wells where the liquid

might adversely affect the chrome plating, rotors without the plating are used.

The rotor is connected to the bottom of a sucker-rod string, while the stator is usually at the bottom of the production tubing. As the rotor spins by means of a surface-drive system, it fuses to the rubber stator, forming tightly sealed cavities that move the liquid at a very steady rate toward the surface for production.

This form of lift is ideal for gassy wells because it can tolerate high percentages of free gas, wells with heavy oil and high-viscosity fluids, and wells with high sand production. It contains no valves or reciprocating parts that can clog, lock up or wear down, and its design and materials make it more resistant to abrasion, which also keeps its cost down.

While the pump itself is hardy—with some sensitivity to fluids—the rods and tubing used with it will still wear out in directional and horizontal wells. Its limited lift capability and its limited production rates also are drawbacks. However, due to this pump's versatility and its ability to be used with other equipment downhole, depending on the application needed, it and its components constantly are being improved upon.

Hydraulic pumping systems

As another economical form of artificial lift, hydraulic pumping systems are generally considered reliable for deep wells with solids, sand, paraffin, heavy oil, water, gas and corrosive fluids that might otherwise hamper production. They also are productive in the deviated and horizontal wells used frequently in hydraulic fracturing. This form of lift works best when there is still high-volume production.

There are two forms of downhole hydraulic lift pumps—those that use a reciprocating piston pump and those that use jet hydraulic pumps. In either case, a motor is placed downhole to help force the pressure upward for production.

Reciprocating pumps generally consist of two pistons placed one above the other along a single rod. Once power fluid (oil or water) is shot downhole via a tubing string to power the

motor, it forces the hydrocarbons to rise up to the pistons. One of the pistons is driven by the power fluid, and the other is used for pumping the well fluids.

The pressure powers the pistons so the fluids can then be forced to rise to the surface for production.

Jet hydraulic pumping systems will take the pressurized power fluid distributed from the surface through the tubing string and force it through a high-velocity jet nozzle. As the pressurized power fluid is shot through the nozzle, it mixes with the well fluids and forces them up to the surface for production.

On the surface, a multiplex positive displacement pump that either is powered by electricity or a multicylinder gas or diesel engine will keep the power flowing through the tubing string to the subsurface pump. The surface pump also includes a cleaning system that is used to prepare the power fluids for their trip downhole. This is useful because it allows for the recycling of produced fluids into power.

Disadvantages for hydraulic lift include a shorter lifespan for surface pumps and the need for constant monitoring for best performance. This high-maintenance aspect makes this form of lift less popular in remote locations.

The bottom line

As companies continue to expand into unconventional territories, there will be a call for new and improved technologies in artificial lift. Optimizing production throughout the life cycle of the well is paramount on every operator's agenda, and they can expect to see many more advances from service companies and those specializing in artificial lift techniques in the near future.

However, there is one piece of advice upon which all artificial lift service providers agree: "Take every well on its merits," Bracken said. "Design the system around that well and around the conditions, and put in the best form of artificial lift based on what the well is telling you. That's how you'll achieve the most production." ■