

By Carter Haydu

**ARTIFICIAL LIFT TECHNOLOGY MEETS INCREASING CHALLENGES OF UNCONVENTIONAL WELLS**

The shadoof was once the pinnacle of artificial lift technology, moving water from its shallow reservoir to another nearby locale with relative ease on the part of its ancient Egyptian operator.

Flash forward a few thousand years and contemporary successor lift technologies in the North American oil and gas sector are basically performing the same task as their BCE counterparts (moving valuable resources from point A to point B), only now they are pumping hydrocarbons from increasingly challenging, deep formations that require not only vertical trajectory but horizontal as well.

“When you lay them on their sides, there are a lot of strange things that can happen with the workings of the downhole pumps,” says Evan West, director and marketing manager at Zedi.

“In addition, with a pump lying on its side, there is often gas associated with oil production, and gas interference either causes or could cause issues intermittently with the pumping performance. As well, a higher percentage of sand is now involved because you get flowback from the fracturing process.”

Because of horizontal drilling and completion challenges on sucker-rod pumping, he notes, it is more important now than ever before that the operator know when problems occur in the well and then make the necessary corrections. “When you have precise rod-string control, it is amazing the things you can do. You can perform subtle, small manipulations to the speeds and accelerations of how you actuate this pump and actually resolve issues.”

SilverJack is Zedi’s hydraulic rod-pumping solution. It consists of a hydraulic cylinder that does the same thing as a conventional pumpjack, but with far more precision, especially when matched with a sophisticated optimization controller and remote access.

“When you determine where plugging is in a pump, then you can go down to the point where plugging occurs and move slightly above that,” West says. “You shorten your stroke length, and if you stroke really quickly and don’t go into the point where the pump is plugged, then you can just visualize it swashing and aerating the fluid column.”

He adds, “We have had several customers tell us that they have cleaned out a pump by using this precise rod-string control, being able to quickly manipulate where and how fast they are stroking.”

**JET SET**

At Calgary-based service company Source Rock Energy Partners the primary focus is the use and advancement of jet-pump technology for artificial lift and well servicing needs. Jet pumps operate by creating a downhole venturi effect, allowing the pumps to lift wellbore fluid simply by pumping a power fluid stream through the jet pump.

“With a dual tubing flow path, we simply pump fluid from surface through a downhole jet pump venturi, which creates very effective suction,” says Kelly Falk, president and chief executive officer.

While previous jet pumps tended to be very inefficient and had a limited drawdown, according to Falk, his company has achieved much higher efficiency performance and can pump off many wells that other artificial lift methods cannot.

“The older styles of jet pump were typically set up so all wellbore liquids and gas came through the jet pump. While jet pumps are an excellent multi-phase pump, Source Rock is well aware that as you approach pumped-off conditions, the volumetric expansion of a gas phase will require more and more jet pump horsepower.

“By installing concentric-tubing jet-pump completions, gas is produced up the casing annulus, and the jet pump horsepower is focused on lifting the wellbore liquids and solids. There is no sense in using the jet pump to pump gas because the gas will flow to surface on its own.”

For Nav Dhunay, president and chief executive officer at PumpWELL Solutions, the latest innovations in the artificial lift space have little to do with the actual, physical mechanics of the lifts themselves, but rather involve the rise of the Internet of Things (IoT) application on the technology—be it a sucker rod, electric submersible pumps (ESPs) or progressive cavity pumps (PCPs).

“With the cost of sensors going down, we are starting to see clients increase the number of sensors they use to gather and protect the data,” he says. “That is really one of the biggest shifts, along with maturing analytics and ubiquitous Internet access. We are certainly on the verge of seeing a sudden jump in the number of [machine-to-machine] devices out there.”

Operational efficiency is the predominant way the IoT improves production on wells that use artificial lift, according to Dhunay, as it enables remote monitoring to maximize production by changing the speed of the stroke in real time and provides preventative maintenance indicators.

“You can imagine fine-tuning a [variable frequency drive] that might be on the sucker rod, PCP or ESP to make sure you are getting maximum oil production while at the same time not overloading the device. There are lots of benefits there.”

Capturing and analyzing mass amounts of data collected on equipment also offers powerful enhancements to the artificial lift, Dhunay says, providing “actionable insights” that improve value, yield and safety in the field.

“We think this will be the next mover for Big Data—as we start to see more data scientist and analyst jobs come into this industry, companies will be looking to apply that knowledge and really convert it into something meaningful that will help them make educated decisions.”

NEW TECHNOLOGY MAGAZINE | MAY 2015

25
He adds, “The days of the easy oil are sort of gone. What we are now dealing with are unconventional plays, predominantly, and that means it becomes trickier for producers to get oil out and even more expensive, and so what we need to do is look at technologies such as Big Data and IoT to help combat that.”

**BIG DATA AND THE IOT**

PumpWELL not only captures data from sensors on artificial lift devices and provides real-time analysis of the well to help operators analyze the information and make intelligent decisions, but the company’s analytic engine can also make recommendations based on certain data patterns, Dhunay says.

“That is another great part of our innovation: if we can avoid people having to make decisions and have robots essentially making those decisions with a second pair of eyes providing validation, operations move forward a lot faster while simultaneously minimizing downtime and workovers, which reduces operational costs.”

This summer, PumpWELL will launch new pattern-seeking software with algorithms designed to capture and use data to make decisions in real time, increasing the amount of oil produced.

“This does not require a lot of handling and labour-intensive duties around the artificial lift,” Dhunay says. “The other aspect of it is the actual IoT. Right now, the price of sensors is coming down but remains expensive enough whereby companies can’t quite afford to make those capital investments up front.

“We are looking to change that model. We are building sensors that are substantially less expensive than anything else in the market today, and we will be able to utilize those sensors all over the pump jack. Cost will no longer be a prohibiting factor.”

According to Dhunay, if remote sensors can confirm a well is pumping and fluid is flowing, then the need to physically visit the site is greatly reduced. If a company considers the costs associated with a full-time employee driving to and from a well, which Dhunay says is between $500 and $1,000 per well per visit, then any innovation that reduces those visits will quickly benefit the bottom line.

“If you could save a single visit by having a remote monitor on a well, which indicates if it is operating correctly, you immediately save $500–$1,000. Those savings can add up really quickly, and that is if you just deploy the remote monitoring aspect of IoT!”

Zedi, too, offers IoT solutions for its customers, using networked and sophisticated algorithms, as well as providing remote communications on all its field instruments.

“Our customers can be anywhere in the world, and if they have an Internet connection, then they have visibility into their wells,” West says, adding that his company is looking to online cloud-based technology for its supervisory control and data acquisition (SCADA) systems.

“That is really what Zedi brought to the forefront in 2000—more of a cloud-based solution as opposed to traditional SCADA systems, which are fairly locked down with visibility as to who uses it and who sees the wells.”

According to West, the future of data analytics involves increased layers of software intelligence, identifying exactly where issues occur and what the operator should do about them. He says, “So it is about the analytics and how you take data to information to knowledge to wisdom and how you make it faster for the customers.”

**PREDICTIVE DIAGNOSTICS**

While different artificial lifts offer their own particular brands of pump solution within unconventional reservoirs, there is no all-encompassing silver bullet, says Rajkumar Shanmugam Mathiravedu, North American artificial lift marketing and technology manager at Schlumberger.

Schlumberger offers a comprehensive artificial-lift product portfolio, matched with an “engineered production solution” that basically involves close collaboration between the operator and the service company throughout the life of the well so as to meet particular lifting needs. “Combining our artificial lift technology portfolio with our expertise portfolio, we are able to provide a holistic approach and do this in a differentiating manner,” says Mathiravedu.

He adds, “The first step is always the lift selection, where we spend a lot of time making sure the artificial lift accounts for proper life cycle of the well.” According to Mathiravedu, the next step is to optimize the selected artificial-lift method, figuring out how to conduct surveillance and trouble-shoot effectively.

“Finally, and very key to this whole thing, is switching the predictive diagnostics. There may be a case where you must change an ESP from a higher size to a lower size or else an ESP failure could happen, or you may need to change to a rod lift. We don’t want any deferred production, and so that is what predictive modelling would do.”

Commercialized in the fourth quarter of 2014, the REDA Continuum unconventional extended-life ESP is the latest offering in Schlumberger’s artificial-lift suite, providing an extended operating range, high efficiency and flexibility on the well.

“So this really translates to operators using one ESP system through the production decline,” says Christopher Brown, artificial lift sales manager for Schlumberger Canada. “If we increase run life, then that also translates to lower total cost of ownership for the artificial-lift technology.”

According to Brown, shale- and tight-oil reservoirs challenge operators with rapidly changing inflow performance, high-gas fraction and abrasives, as well as the demanding flexibility to adapt to the quickly changing inflow performance of those reservoirs. Improper management of these factors could lead to increasing lifting costs, premature rig intervention and accelerated pressure depletion.
For example, companies often flow wells until production declines to a certain rate. The operator will purchase and install some sort of artificial-lift system, such as a rod lift, and produce with that for a while. Production continues to decline, which could result in purchasing a second system and reinstalling it on the same well.

“Operators will repeat this procedure many times over in those high-density drilling programs. ‘That is what is typical for shale- and tight-oil developments,’ Brown says.

With its new high-compression design, the REDA Continuum unconventional extended-life ESP comfortably operates at low flow rates and manages demanding production declines that are typical of an unconventional well, Brown says. Therefore, the company can install and run a Continuum ESP system, possibly mitigating the number of workovers required and extending how long the device is producing before switching to another artificial lift.

According to Schlumberger, an operator installed the Continuum ESP system in the U.S. conventional market as a transitional method to help restore production where anticipated natural flow was projected to be 4,000 bbls/d. The Continuum system increased incremental production for the better reservoir performance to 5,000 bbls/d.

Although production has declined, the well reportedly continues to produce with no interruptions eight months after installation in 2014. The technology is also proving to be useful in Canada as a transitional ESP method to help enhance initial production.

“Most notably, this is an enhanced-compression design which was built with metallurgies specific to handle abrasive wear,” Brown says.

“In addition, the flow path has been designed within the stage itself in order to help with production of fluids with high sand concentration. The pump can be configured with an abrasion-resistant technology that places a bearing and sleeve up to every stage, which again will enhance the run life,” he adds.

“The Continuum pump also has an extended operating range. By utilizing this new compression design, we can comfortably operate at low flow rates and manage the production decline that is typical in unconventional wells.”

By complementing its hardware with consultation services, according to Mathiravedu, Schlumberger can extend the run life of a particular lift system and improve cash flow through accelerated production and continued operation.

THE NEXT GENERATION

The conventional pumpjack is a tool of the vertical-well era and was never designed to pump on its side. However, says West, pumping on its side is exactly what industry demands of artificial-lift technology in today’s unconventional realm of horizontal drilling and hydraulic fracturing.

“Historically, when those [pumps] were run vertically, it was fine but now we are literally bending them around corners, and you have situations where your sucker rod is wearing on the sides of tubing. ‘There is more importance, again and again, to be able to see what is happening downhole and when there are situations with holes in the tubing and your rod string wearing out.’

With its hydraulic system, Zedi can calculate very accurately the rod-string weight, meaning the operator can tell when normal weight transitions occur. Every rod-string position should have a certain character signature based on transfer weights, West says. Gas interference, gas locking, debris in the pump, travelling-valve issues, standing-valve issues—all these show up as different character signatures.

“Personally, I think that with hydraulic-rod pumping, its precision and the capabilities Zedi brings to hydraulic-rod pumping, this is the next generation of rod pumping,” says Jeff Saponja, chief executive officer at TriAxon Oil and Production Plus Energy Services. “The rod pump that has been around the past 50 or more years is really designed to run vertically, and it does not like going around the bend.”

One issue, according to Saponja, is that horizontal wells do not allow operators to “sump the pump.” This refers to running the pump below the reservoir in a vertical well so as to maximize production by pumping off the well to the lowest pressure possible, while also providing the capacity to remove any solids that come along with production before entering the pump.

“There is no sump now because we turn the wellbore into the reservoir horizontally. A rod-pump configuration with
no sump is one of the reasons [the downhole pump] has lost its efficiency in a horizontal-well configuration. All flow from the horizontal, which can include solids and gas, enters the pump directly, causing run-time challenges and a reduction in pump operating life.

To make matters worse, solids naturally accumulate at a 30–65-degree slope region of the wellbore’s bend or heel section—exactly where the downhole pumps are commonly positioned. Saponja says: “We end up creating a situation where we have very poor run times due to gas interference, we can’t pump the well off to maximize production and we have higher workover frequencies because of solids damage.”

Working in a deep Viking light-oil reservoir a couple years back, TriAxon realized these big, long horizontals are actually very good natural separators for oil and gas entering the wellbore. When they separate, according to Saponja, the resulting flow out of the horizontal wellbore becomes messy and inconsistent. Inconsistent flow from the horizontal wellbore means at times the downhole pump sees all gas or all liquid or highly variable rate combinations of both. Inconsistent flows also create mechanical wave action along the horizontal, migrating solids to the bend section.

“No artificial-lift system likes messy flow, and so our hypothesis was that maybe the solution for successfully artificially lifting horizontal wells is to regulate flow out of the horizontal to smooth it out and stabilize it. We observed from interruptions to producing wells—for example, a short-term power failure—that the flows became even more messy and inconsistent, which resulted in even greater inefficiencies.”

Saponja and his team actually knew from underbalanced drilling practices how to smooth out inconsistent flows, and they could therefore resolve inconsistent flows of the horizontal using underbalanced drilling techniques.

He says, “We also asked ourselves another key question: why is everyone trying to solve artificial lift with one system—either a rod pump, ESP [electric submersible pump], gas lift or screw pump? Then we asked the question: why can’t we run two different artificial lift systems in sequence and have them work harmoniously?

“The absolute king for artificially lifting the vertical section of the well is the rod pump, so let’s leave it alone. It is happy in the vertical, it’s efficient, it’s low cost to maintain, and operators at surface are familiar with its operation. It just does not like being around the bend.”

The team then focused on the most efficient artificial lift system for the bend—a system that provides maximum drawdown and run time, is tolerant to solids and provides the ability to regulate inconsistent flows.

In November 2013, TriAxon established Production Plus to develop the patent-pending HEAL System for the horizontal well’s bend section. With no moving parts, a large solids and advanced-separation technologies that bridge two different artificial-lift systems, this solution makes the horizontal “think” it is a sumped vertical.

By smoothing out the flow, controlling damaging solids and placing the rod pump out of the bend section, pump efficiencies increase dramatically and jack loadings reduce materially.

“We pass on to the rod pump mostly gas and solids-free liquid in a smooth manner. How happy is the rod pump when it is seeing very consistent liquid? It is very happy,” Saponja says. “All of a sudden, our run times went from 70–80 per cent to nearly 100 per cent.”

First installation of the HEAL System was in March 2014. Pre-installation, the subject well’s runtime was about 70 per cent per month, with roughly three workovers per year to replace failed pumps. Post-installation, Saponja notes, the well has not been down once, and the pump has not required changing.

“With this system, we have been able to produce the well not only with great runtime, but at a lower bottomhole pressure than could be achieved, pretty much, by any artificial-lift system. We are producing the well generally at around 200 kilopascals at the bottom, which is an extremely low pressure at 2,300-metres vertically deep.

“That has been a huge value-add for the well. You are looking at a $1.2-million addition to net present value on the well as a result of installing that system.”

Currently building multiple units, Production Plus manufactures in southeastern Calgary. The company’s intent is to take this technology to the U.S. in the fourth quarter of 2015, as the HEAL System appears to be ideally suited for the Eagle Ford, Permian and Bakken.

According to Saponja, the system is effective in medium and light oil, as well as liquids-rich gas scenarios. While Production Plus has yet to apply the technology to heavier oils or SAGD, it should provide higher reliability in those environments as well. The system is also showing promise for gas well de-liquefaction and enhanced frac flowback efficiencies.

Currently, Saponja notes, the system is installed on over 30 horizontals in seven different Canadian reservoir horizons, improving production performance on each well by 10–30 per cent. He adds, “This technology was born out of an operator who faced many production challenges and recognized limitations with current artificial-lift systems. The mother of invention here was the pain of those challenges.”