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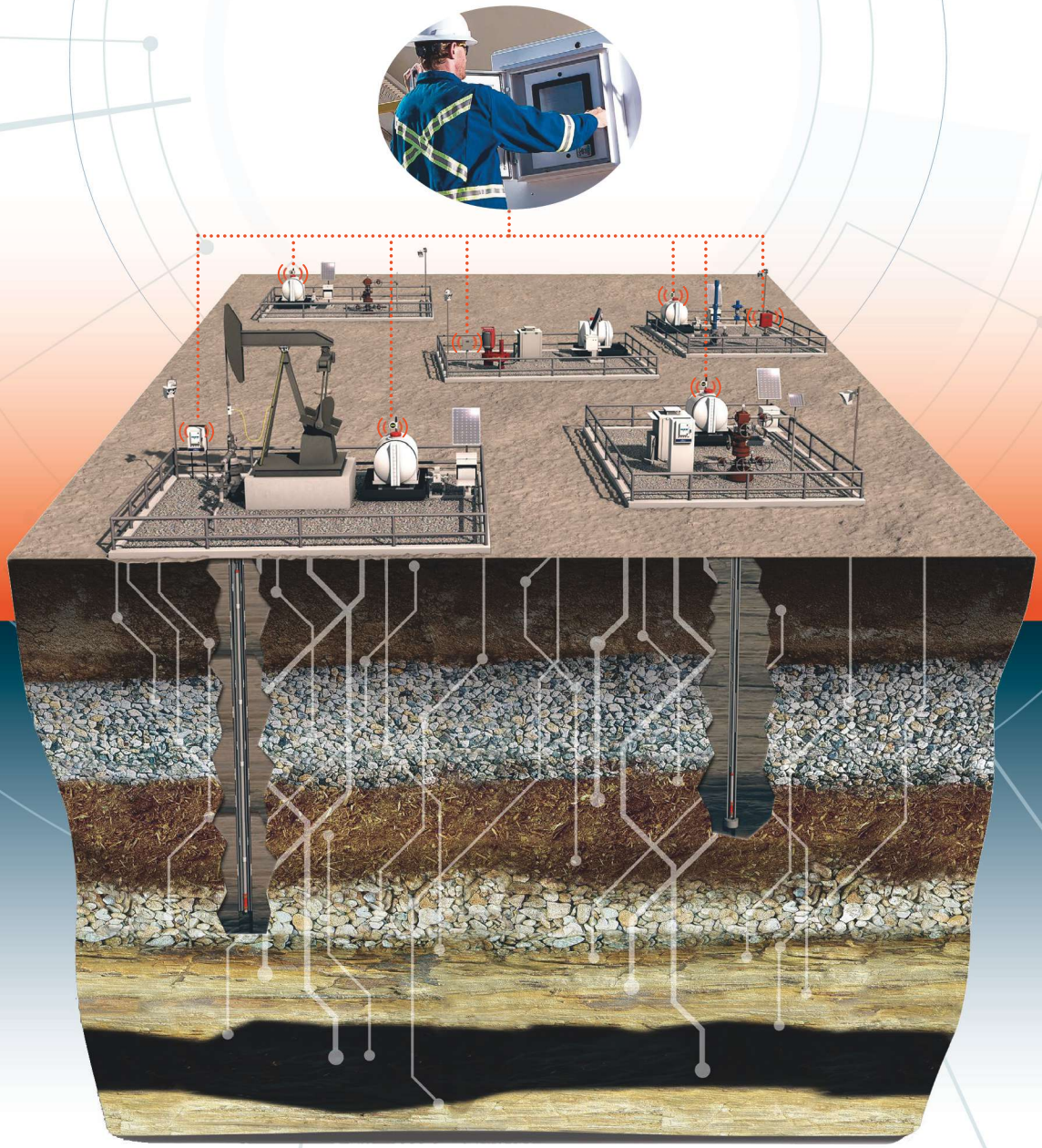

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Artificial Lift
The 2019 Techbook

A supplement to *E&P*

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Hart Energy's Techbook Series

The 2019 Artificial Lift Techbook is the 18th in a series of techbooks in which Hart Energy will provide comprehensive coverage of effective and emerging technologies in the oil and gas industry. Each techbook includes a market overview, a sample of key technology providers, case studies of field applications and exclusive analysis of industry trends relative to specific technologies.

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On the cover: Multiple beam lift units deliver fluids to the surface in California's rolling hills. *(Photo courtesy of California Resources)*

Back in the Saddle

The artificial lift market for unconventionals is on the rebound after recent commodity price uncertainty impacted both utilization and the bottom line.

By Blake Wright
Contributing Editor

There is no secret to the key to success in the oil patch: Amass the best assets, technology and people, then work collectively and efficiently to squeeze every last economic drop of resource from the subsurface. Looks simple on paper, but it has been and remains the perpetual goal of operators worldwide since George Bissell and Edwin Drake drilled their historic 70-ft keeper near Titusville, Penn., in 1858. Things have changed quite a bit since Drake's Folly, but the pursuit, discovery and production of hydrocarbons are still driven by visionaries with a mind for innovation and an eye on the horizon.

To that end, companies commit a generous amount of resources to ensure they are securing the best returns, both from the ground and for their shareholders. The importance of efficient and maximum resource extraction is rarely understated—a healthy stream of hydrocarbons is what fuels a healthy stream of revenue. In more modern times, as industry unlocked more and more unconventional resources around the world and particularly in North American shale plays, the challenge of effective maximization on all fronts became more daunting, pushing the limits of existing technology and corporate ingenuity.

Artificial lift systems have been around for decades, having been designed to increase the flow of liquids up a well by lowering the producing bottomhole pressure on the formation. In simpler terms, the systems work to squeeze every last economic drop of resource from the subsurface. There is no one-size-fits-all lift system; instead, there is a myriad of solutions that work most effectively dependent on the field variables at the point of their introduction. Electrical submersible pumps (ESPs) might be the most popular for initial lifting of a high rate well, while gas and rod lift systems are more readily introduced once the flow rates of individual wells begin to drop. The market had a tough run during the oil price plunge in the middle of the decade but appears to be on the rebound with estimates of 6% growth through 2020 being predicted by pundits Westwood Energy.

Need more proof? Just watch the money. Tubulars specialist Tenaris built a sucker rod manufacturing facility in Conroe, Texas, back in 2017, but delayed its opening due to the downturn. The $70 million facility will now open this summer. Additionally, Weatherford president and chief executive Mark McCollum told investors in February that the contractor expects "strong demand" for its artificial lift services in 2019 with declining production on older shale wells driving higher demand for the company's rod lift systems.

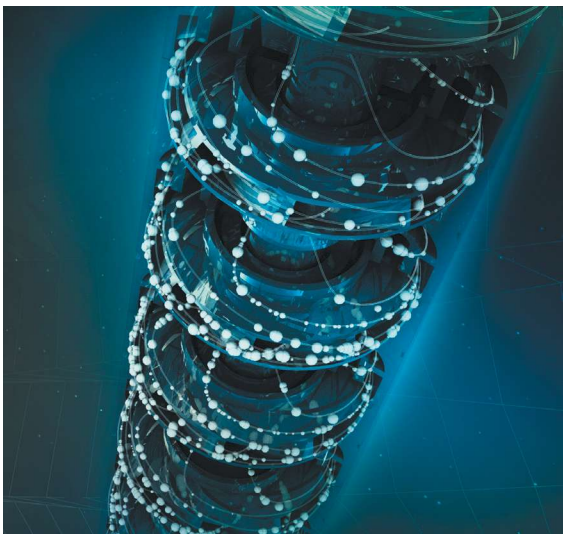
Apergy, a company that specializes in lift systems, saw its 2018 monthly ESP install rate in the Permian Basin of West Texas grow 2.5 times its 2016 rate. The company's ESP revenue growth was over 70% in 2017 and that growth continued last year.

That's not to say there won't be hiccups along the way. Oil prices took a dip in the fourth quarter of 2018 and with it the number of well completions. According to Baker Hughes, a GE company (BHGE), 2018 marks the first time since 2015 that crude oil prices ended the year lower than at the beginning of the year. However, the company added that it expected the market for artificial lift service to remain stable.

"What we at BHGE have in terms of artificial lift is possibly the widest portfolio in the industry," said Valerie William-Eguegu, global product line manager for Gas Management and Unconventional Artificial Lift Systems, with BHGE. "For unconventional applications, what we've seen over the years is a shift in wanting to design from the onset, for the

Summit ESP engineers continuously monitor wells on a 24/7 basis from a state-of-the-art monitoring center. The engineers have access to a complete 360° view of every well's operational information, downhole equipment, application design and field service history. *(Photo courtesy of Halliburton)*

challenges which may be faced in typical unconventional applications. If you look at the shale market, a common issue with shale is rapid decline of the wells, so we need a system that can cope with going from about 3,000 barrels per day to 300 barrels per day in six months, without needing to change out the system. That was one of the first things we did in our portfolio, what we call our FLEXpump series of ESPs, which is a pump that can operate at high efficiency in that wide of a range, which the industry had not seen before then."



Baker Hughes, a GE company's FLEXPump series electrical submersible pumps can handle flow rates ranging from 50 bbl/d to 10,500 bbl/d, ideal for unconventional plays in which production declines rapidly. *(Image courtesy of Baker Hughes, a GE company)*

ESP reliability is an issue the industry has been desperate to address. These pumps can take a monumental beating downhole and, depending on several factors including the subsurface architecture, can run without fail for several years—or for just a matter of weeks. ESPs are powered equipment with moving parts, and ultimately, as with any system that depends on more than one component to perform, the lower reliability can be.

"Everything is application dependent," William-Eguegu explained. "Having said that, the way we manage our products, we break down the components of an ESP—pump, motor, cable, motor lead extension. Then we drill down into these components to figure out what we can do better with each of them. I would say that we're breaking that jinx. It doesn't mean that we don't have situations where it's the wrong application or the wrong operating method, which may cause early failures of the systems, but generally we are seeing lots of longevity and need to pull the system only when the reservoir completely changes or it is a full-field workover. Every aspect of our new product development or modifications passes through strong reliability criteria. In the context of what we are dealing with we are seeing improvement."

Rapid decline is just one issue lift systems must attempt to counteract. Additional issues include dealing with impurities like gas and solids coming in the well due to the makeup and sheer amount of frac sand that is used in shale development.

"One of the challenges our customers face is solids and solids flowback," said Frank Corredor, Summit ESP Optimization and Monitoring Group manager. "Last year we introduced a new tool called the SandRight Solids Fallback Preventer. This

component helps handle the sand that makes it into the tubing strings. During shutdown events the sand flows back into the pumps, causing failures. With the SandRight tool, the sand stays above the pump and away from the well. This has been a tremendous success and our customers have really seen the value in this piece of equipment."

While innovation continues in the artificial lift market, it hasn't prevented operators from testing the waters on several different methods of lift, switching out one system that might be underperforming for another that might be better suited to the formation. Typically, ESPs have been the solution of choice for those looking for an early boost soon after a well is brought online, but later different solutions are sometimes introduced in an effort to both stabilize a shrinking production profile and improve well economics. Gas lift has been one of those methods that has gained traction in recent times.

"We have seen a shift over the last couple of years. Before 2014 or 2015, we saw companies that would immediately put a well on ESP, transition to rod lift, and that was it," said Kyle Chapman, president, Production at Weatherford. "Those were pretty much the only forms of lift you would see in the Permian, for instance."

As the shale revolution developed, other forms of lift became prominent, including gas lift, he said.

"Specifically talking about the Permian, gas lift makes sense because they have the excess gas and have the infrastructure in the field," Chapman said. "It is a good, reliable form of artificial lift and it comes at a reduced cost compared to an ESP. They are using gas lift as much as they can, and they are using it for longer than they would have in the past."

A number of micro-trends have also emerged in the U.S. including operator use of continuous rod. The method has been used in Canada for decades, and it is a common form of connecting the pump with either the drive head or the pumping unit depending on what kind of lift is employed. With the exception of California, it has yet to fully catch on in the U.S.

"We're seeing use of our COROD continuous rod products expand, especially as operators in the unconventional plays go for longer horizontals," Chapman said. "Using COROD reduces tubing friction and extends pump runlife. Further, combined with technologies like our Rotaflex long-stroke pumping units, COROD can help our clients lift more fluids from deeper wellbores, which is key to plays like the Permian and Bakken."

Another popular method of artificial lift has been the return of the jet pump. A technology that has been around for decades, jet pumps are now being used more and more as an alternative form of lift, especially early in the production cycle. Part of the appeal is the lack of need for a rig to work over the well if the pump fails.

"One of the challenges with jet pumps is that they are great when the well flows at a high rate, but once the well starts to slow down and there is not as much fluid running through it, the pump can cavitate," Chapman explained. "To answer that challenge, we've come out with two new jet pumping solutions. The first is the inverse, or low-flow jet pump. It changes the downhole fluid path when it reaches the pump, which lets us put jet pump technology into lower flowing wells."

Weatherford has combined jet technologies with a hydraulic pumping system to create a centrifugal jet pump. This basically provides the power of an ESP on the surface without the inefficiencies and expense of a downhole ESP. *(Photo courtesy of Weatherford)*

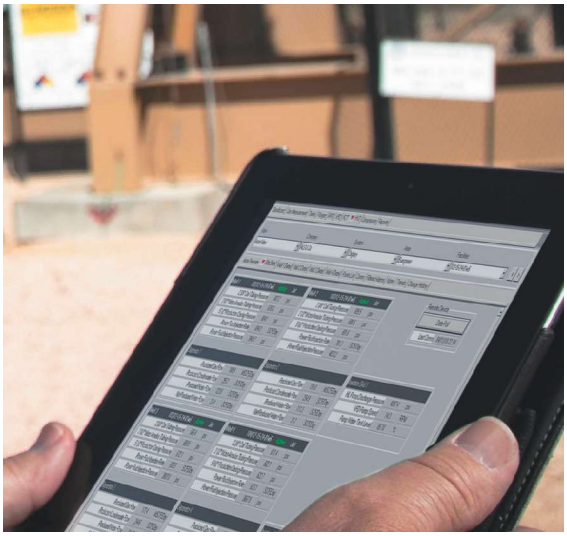
The second jet pump innovation is replacing the multiphase triplex or quintiplex pumps on the surface, according to Chapman.

"We've coupled our jet technologies with a hydraulic pumping system (HPS) to create a centrifugal jet pump. This basically gives you the power of an ESP on the surface without the inefficiencies and expense of a downhole ESP," he said. "Further, we've developed intelligent control algorithms that can control the HPS—our ESP on surface—to speed it up or slow it down depending on what the well is giving you. In the past, when you just had a standard triplex pump out there, all it did was pump, and there wasn't really any intelligence to it. But, by using the big data and machine learning inherent to our CygNet IoT and ForeSite optimization platforms, that pump now works autonomously and at peak efficiently. It's a step-change in efficiency versus what we had in the past."

Another shift in the artificial lift segment has been the move toward predictive management versus reactive services. Contractors are communicating better and more frequently with their clients from the very beginning of field development to ensure the right solution is applied given the budgets, schedules and subsurface conditions unique to each situation. Most trace that change back to 2014, following the precipitous drop in oil prices. Prior to that time, ESPs were treated more like a piece of replaceable equipment—almost disposable. Operators simply accepted that well conditions were negatively impacting the equipment.

"After the downturn, we began working more closely with our operators in unconventional fields, advising them on how to improve wells though looking at historical data," Corredor said. "We've always viewed client relationships as alliances, but when we started predictive management, we started looking at all of the parameters—both under our control and those that were not under our control. Initially, progress was slow on obtaining the outside parameters. To be successful at well monitoring and optimization, we had to fully partner with our customers. In turn, the operators have to partner with their field personnel. It has to be a team effort. We started closing the gap. That is when operators started changing the mindset and accepting that remote change and remote optimization were possible."

The new sense of cooperation yielded results. Examination of the trends in the field showed a lack of available workforce with artificial lift knowledge—a best practices primer to keep some of the lift equipment, especially ESPs, operating as they should.



Weatherford has developed intelligent control algorithms that can control its centrifugal jet pumps—essentially an ESP on surface—to speed it up or slow it down depending on well flow. *(Photo courtesy of Weatherford)*

"That was another challenge," Corredor said. "The people working in the field didn't have the training to operate ESP equipment. Initially, troubleshooting and repair wasn't part of their job. Sending field techs to help solve issues wasn't always practical from budgetary or HSE perspectives. So we started transferring knowledge to the field, helping our customers to understand best practices on how ESPs operate. We also started capturing KPIs [key performance indicators] on uptimes. Working together, we started documenting all the reasons why the customers' ESPs were experiencing shutdowns, which helped us understand their challenges.

"One of the well monitoring group's tools is Summit Knowledge [SK], a digital workspace used to monitor all manufacturing and operational work, as well as to capture the entire story on how the ESP system is operating. Most often, the problems began while installing the systems and starting without proper instrumentation. We recommended remote operations to begin capturing the historical data on tubing and casing parameters in order to understand the system. Our customers saw the importance of remote monitoring. Before SK, when performing remote changes without key parameters, a colleague of mine compared it to driving blind. It was very difficult. We didn't have all of the data. We didn't know vital conditions, like when the ESP was surfacing fluid, if the right backpressures were being applied at the surface, or if there were issues with the flowlines, bad chokes or bad backpressure valves. Having an

optimization center to analyze the challenges from multiple operators, along with a platform to store all data, allows the Summit ESP monitoring group to apply lessons learned to help those who are struggling to better understand and optimize their wells."

Life of field knowledge equated to a better understanding of how individual reservoirs would react to these different lift systems. Many operators still employ multiple systems on any given field, sometimes on any given well due to the strengths and limitations presented by any one solution. Historically, operators never shied away from using upward of three different artificial lift systems on any single well over its producing life to help keep project economics in line with expectations.

"It ultimately depends on the operator, but they can only make those decisions based on what they know is available," William-Eguegu said. "Rod lift systems are great. They work. But they can only go so far down into the well, at certain depths and certain deviations. That's where we move into ESPs, but ESPs are constrained in that regard and this is where we come into some of our newer innovations such as the CENesis CURVE tight-radius ESP system to address those gaps. None of it is negated fully. Each method comes with its pros and cons. You have some operators who employ hybrids—gas lift with an ESP, just because if the ESP is down and you have excess gas, you can use the gas as a form of lift, and when the gas runs out it's back to the ESP. Gas lift can only go so long before it loses its economic value because you still have to compress the gas to send it down the well. You might have platform constraints if you are offshore, or it might just be a tight fit depending on your area of operations or the added cost of compression.

Baker Hughes, a GE company's CENesis Curve tight-radius system enables operators to land the ESP system closer to the pay zone to maximize production and reserve recovery. *(Photo courtesy of Baker Hughes, a GE company)*

"What we do for our customers, especially those starting out in new fields, is map out all of the artificial lift options," William-Eguegu continued. "For us, it is easy to do because we cover all of the ranges of artificial lift possible. We can tell the story of the field via the production profile and say that we think for wells A to C the increment you get via an ESP versus gas lift isn't worth the economics so maybe just go with gas for these wells because they are so shallow, but maybe for this other section you can start with gas, but you will need to move to ESPs or plunger/rod lift. If the type of oil you have is heavy it might put you more in the PCP range. We have software tools that will help customers manage the artificial lift life cycle of their fields ... what the production options are for the life of the field. Ultimately it is up to them, be we can offer the knowledge of what is possible."

The future remains in flux, but there are a few items on the horizon that are expected to change the game yet again for artificial lift and the oil patch as a whole—slug prediction, wide-spread rigless deployment of ESPs, continued evolution of pumping systems, the use of a rod pump in a long horizontal, as well as the harnessing and culling of Big Data to build a better oil field.

"The buzzword of the day is 'Industry 4.0' or the 'fourth industrial revolution,'" Chapman said. "People have been talking about it for a while, but now we are seeing operators saying let's take a look at this and try it. It is combining that Internet of Things [IOT] technology that gives you the use of high-frequency data. In the past, most of the wells in the U.S. might have yielded some basic information from a SCADA system and some rudimentary telemetry. It may pull once an hour or once or twice a day, so you're seeing a snapshot of what the well looks like at that moment. With the IOT tech, you get continuously streaming data—a datapoint for every millisecond if you want it. It costs something to send that, but you can take that high-speed data and cloud storage and you are starting to see operators look at that and ask what is the true performance of my wells? The data can allow them to make better decisions, faster." ■

Valiant field service technicians arrive before sunrise to complete an ESP installation on a well site in Midland, Texas. *(Photo courtesy of Valiant Artificial Lift Solutions)*

Advancements Are Being Made in Artificial Lift, Automation

These artificial lift key players are focused on innovative developments and cost-cutting technologies.

By Ariana Hurtado, Associate Managing Editor

From electric submersible pumps, progressive cavity pumps and gas-lift systems to monitoring and automation services, artificial lift providers continue to improve and develop innovative technologies. With the goal of maximizing production and efficiencies, the following service companies offer artificial lift services in areas ranging from automation, equipment and telecommunications.

Key Players

ABB

ABB offers a wide range of artificial lift products such as controllers, instrumentation, flowmeters and data analytical software.

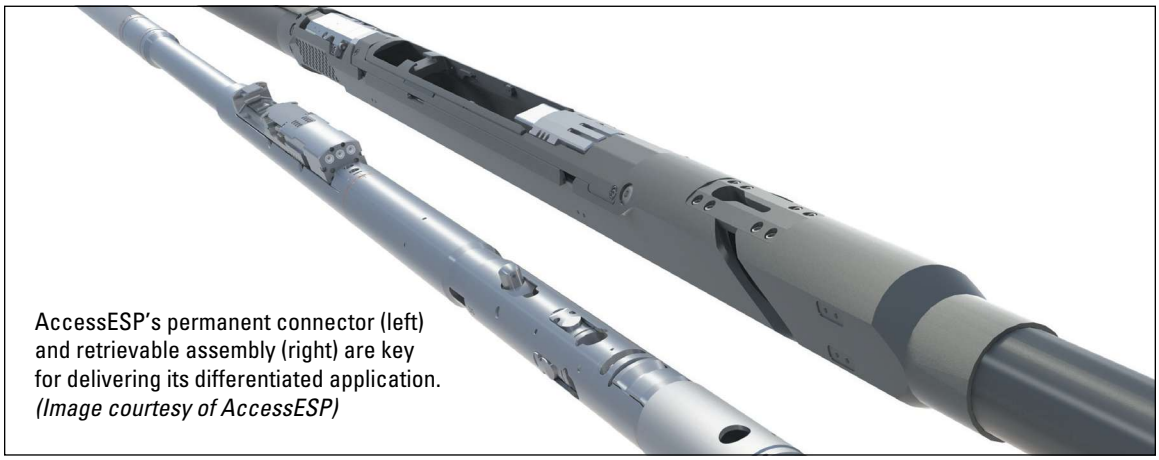
The company's plunger lift solution is a staple of its automation offering backed by a highly scalable line of controllers and instrumentation and industry expertise, according to the company.

ABB's application has improved production, lowered costs, increased operational efficiency and helped with HSE metrics. Options like the company's autotune optimization can automate set point adjustments within limits based on enabled options. Hold options allow automation to assist with non-arrival recovery, high line pressure situations or well pad control scenarios involving multiwell pad plunger production synchronization. Additional features include the ability to track plunger mileage for a preventative maintenance program, full plunger cycle log history, trending of tubing, casing, line pressure and flow rate as quick as every second, according to the company.

ABB's plunger lift application is not a standalone solution. Over the life cycle of the well, the software applications natively have the ability to enable artificial lift applications such as gas lift, gas-assisted plunger lift, intermitter, chemical injection and plunger lift. Custom programming is also an option, utilizing the IEC 61131 programming language preferred.

AccessESP

AccessESP provides rigless thru-tubing wireline retrievable electric submersible pump (ESP) technology. With installations around the world, the company's system is designed to address the high intervention costs and deferred production typical of offshore, remote onshore and high-production ESP wells. The side pocket wet-connect system configuration is designed to allow slickline retrieval without killing the well while providing fullbore access to the lower completion when retrieved, without the need for pulling the tubing.



AccessESP's permanent connector (left) and retrievable assembly (right) are key for delivering its differentiated application. *(Image courtesy of AccessESP)*

AccessESP also provides permanent magnet motor (PMM) technology and has recently released a new high-performance power delivery system for ESP installations.

During 2018 AccessESP continued with more installations and supported several live well cleanup interventions.

In addition, AccessESP released a life-cycle solution that moves away from the industry's traditional "run-to-fail" method. According to the company, the systematic approach combines AccessESP WRESP equipment, downhole measurements and analysis with a unique solution involving equipment preventative maintenance.

Ambyint

Ambyint provides artificial intelligence (AI)-driven artificial lift and production optimization solutions that are designed to deliver increased efficiency with 10%-plus production improvements and reduced opex of 20%-plus. The company integrates traditional physics-based methods with modern AI and machine learning capabilities. Ambyint's AI algorithms work by training artificial lift systems using real-world data. Rather than telling the system what conditions to monitor, Ambyint's system learns by analyzing all available data to identify parameters that are leading indicators of an issue, such as gas lock or paraffin buildup, that are not apparent to the average user. The Ambyint platform provides predictive analytics, enhanced real-time visualization of wells, remote visibility and control of the well site.

The company has gathered more than 100 million pump operating hours of high-resolution data from artificial lift and monitoring systems, derived from thousands of wells. Enabled by a large-scale training dataset, Ambyint's technology provides continuously updated and tuned models, which enable an inference engine to proactively identify key production issues including detection, characterization and prediction of well anomalies or potential wellhead leaks. By digitizing the visual input from millions of dynocards, Ambyint's AI platform is able to perform micro-pattern analysis to diagnose downhole and surface anomalies and optimize well parameters. Ambyint's system works for a variety of lift types, including sucker rod lift, progressive cavity pump and plunger lift.

Ambyint's Amplify real-time controller (orange device on the gray panel) helps improve efficiencies. *(Photo courtesy of Ambyint)*

Apergy Corp.

Apergy's Production and Automation Technologies Division (formerly known as Dover Artificial Lift) offers a complete suite of artificial lift products and services. Apergy delivers its SMARTEN automation total asset manager as well as support and solutions aimed at boosting production efficiency and lowering lifting costs.

The company's ongoing innovations in rod lift, plunger lift, progressing cavity pumping, gas and hydraulic lift along with electric submersible pumps are designed to provide cost-effective and reliable solutions for every situation.

In partnership with Liberty Lift Solutions, Apergy has combined brands, products and services to offer the Liberty Lift Long Stroke (XL) Pumping Solution, which is designed to "provide a rod pump solution suited for work in deviated, deep or high-volume wells to manage production costs at an optimum level," according to the company.

With a suite of intelligent software, predictive tools and expert services, Apergy enables its partners to

Apergy's Norris Rod technician gets ready for a day's work in the Permian Basin. *(Photo courtesy of Apergy Corp.)*

visualize and optimize wellsite performance, increase safety and improve return on investment.

Apergy also can custom tailor solutions for customers.

Artificial Lift Performance Ltd. (ALP)

Artificial Lift Performance Ltd. (ALP) offers a cradle-to-grave solution for management and optimization of electric submersible pump (ESP) and gas-lift produced wells by helping operators understand the key performance indicators related to their artificial lift systems.

ALP's software is written by production engineers for production engineers. "The automated well test analytics module provides ESP operating recommendations and optimal gas injection rates," the company said. "The diagnosis module offers vendor runlife performance tracking as well as root cause of failure recording and reporting. Management-by-exception processes ensure that opportunities and problems are presented, so that the entire operations team can stay focused on the right priorities."

ALP's Pump Checker ESP production optimization software provides a consolidated view of all the pumps and systems an operator uses to allow engineers to react more quickly and efficiently. Pump Checker integrates the data from real-time and static data sources onto a single platform and then arranges the data from all the sources to give a standard presentation for each well.

The company also has added an ESP design module to Pump Checker that allows a complete analysis of pump stage and horsepower requirements over the life of the well. The software allows comparison of different pump types to select the most efficient solution over the life of the well (Figure 1).

According to the company, ALP's recommendations have helped several operators boost fieldwide production of more than 5% in thousands of conventional and unconventional wells since 2014.

In addition to software, ALP can support artificial lift operations through training and consultancy.

Baker Hughes, a GE company

Baker Hughes, a GE company (BHGE), offers electric submersible pump (ESP) systems, rod lift systems, progressing cavity pumping systems, horizontal surface pumping systems, gas-lift systems, surface electrical control systems, and monitoring and automation services.

The company's TransCoil rigless-deployed ESP system, developed with Saudi Aramco, is designed to allow operators to eliminate the need for a rig during ESP workovers, helping them to lower intervention costs and minimize deferred production. The system can be installed through 4½-in. production tubing, saving the time and money required to pull the existing completion, which is especially valuable for mature offshore wells, according to the company. By connecting an inverted ESP system directly to the power cable, the TransCoil system eliminates the power cable-to-motor connection as well as an in-well electrical connection.

The company's Magnefficient permanent magnet motor, which is designed to improve efficiency by lowering ESP system energy consumption, delivers a higher power density, enabling operators to achieve a higher horsepower with the same motor or the same horsepower with a smaller motor, according to the company.

BHGE's artificial lift systems group has 15 key manufacturing facilities located worldwide and

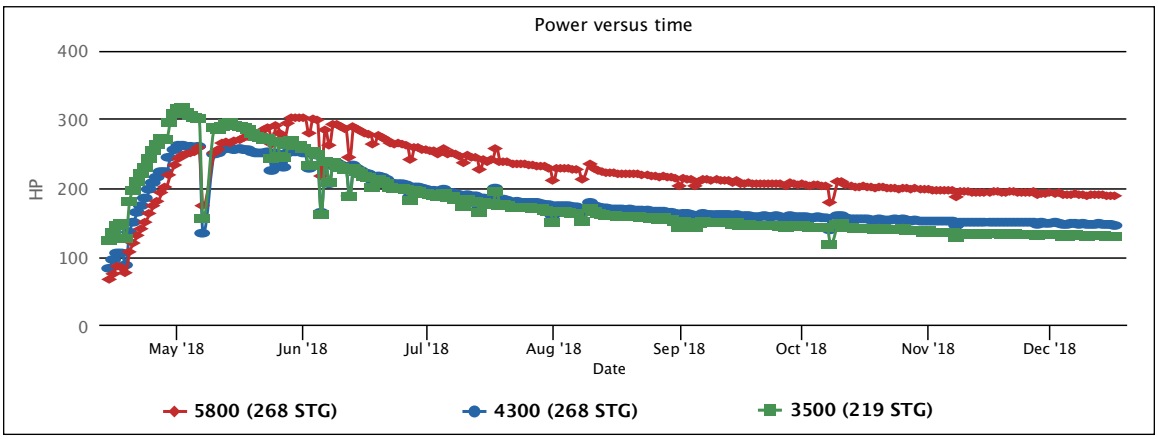


FIGURE 1. The pump HP requirements are shown for different pump stages over the life of the well. *(Data courtesy of Artificial Lift Performance Ltd.)*

BHGE's artificial lift footprint includes 15 key manufacturing facilities and many assembly, maintenance and repair facilities around the world. *(Photo courtesy of Baker Hughes, a GE company)*

four primary R&D facilities in the U.S. and Europe. BHGE's Artificial Lift Research and Technology Center in Claremore, Okla., allows engineers to create, develop and test solutions for production challenges and improve the reliability of artificial lift systems. BHGE's Artificial Lift Center of Excellence in Dammam, Saudi Arabia, manufactures the full range of the company's ESP portfolio and employs more than 100 technical professionals.

In December 2018 BHGE partnered with the Petroleum Development Oman (PDO) to open its first artificial lift systems assembly and repair facility in Oman, according to a company news release.

"The center, located in Nizwa, Oman, is one of the largest investments by BHGE in the country. It specializes in the assembly and repair of ESP components, including motors, seals, intakes, gas separators and pumps, and has competencies for testing all types and ranges of pumps and motors to ensure quality control," the press release stated.

Borets

Borets is a global supplier of electric submersible pump (ESP) systems, manufacturing more than 12,000 systems annually. Borets also was the first company to engineer and manufacture permanent magnet motors (PMMs) for oil industry ESP systems, according to the company.

Borets ESP systems using PMMs help operators reduce lifting costs. The Axiom II variable frequency drive, using a proprietary vector algorithm, controls and optimizes Borets PMMs to help reduce electrical power consumption by up to 20%.

Borets PMMs experience lower heat rise than induction motors, which means improved equipment longevity and reliability, according to the company.

The higher rotor horsepower density available from Borets PMMs provides operators the additional benefits from shorter equipment length and smaller outer diameter motors. The 406 series PMM, with up to 264 hp, offers deeper pump setting depth possibilities as well as additional annular clearance for better motor cooling and gas breakout in typical 5.5-in. casing sizes. For higher horsepower requirements, the 456 series PMM is available with up to 400 hp in a single section just over 34 ft in length.

PMMs are a key enabling technology for Borets new wide-range and wear-resistant ESP technology. Striving to better manage the rapid decline rates typical of unconventional production, the WR2 ESP system utilizes high-speed PMMs as well as pump design and manufacturing techniques in an ESP capable of operating from 4400 bbl/d down to 250 bbl/d.

Borets has shipped, sold or installed more than 12,000 PMMs globally and in 2018 installed its 250th PMM in the Permian Basin.

The Axiom II variable frequency drive controls and optimizes Borets PMMs to help reduce electrical power consumption by up to 20%. *(Photo courtesy of Borets)*

Desert Downhole Tools

Founded in 2013, Desert Downhole Tools delivers expertise for workover and completion operations throughout the Permian Basin. The company offers a comprehensive inventory of packers, retrievable bridge plugs and accessory equipment from most major independent tool manufacturers, including Weatherford, D&L Manufacturing, Magnum International Composite Plugs, Map Oil Tools and Kline Tools. Desert also provides repair services for packers and tubing anchors.

DistributionNOW

DistributionNOW (DNOW) artificial lift division supports the full production process flow, from rod pump to LACT unit. DNOW can complete system designs and performance analysis for rod pump, plunger lift and PC pump wells. DNOW manages a robust inventory of ALS parts and equipment including conventional and hydraulic pumping units, variable frequency drives and automation systems, wellhead and downhole components, progressive cavity pumps (PCPs) and a wide range of plunger lift equipment.

The primary focus of DNOW's artificial lift division is reciprocating rod pump systems and services. DNOW can improve wells using technical expertise, field-based experience and programs (e.g., RODSTAR, SROD and C-FER PC-PUMP). The pump shops utilize parts from a qualified list of manufacturers and Dura Products, a wholly owned North America-based DNOW manufacturer. The company also leverages in-house plunger-lift experts and three PC Pump facilities with comprehensive testing capabilities. DNOW operates 35 facilities in the U.S. and 18 in Canada; these service locations are strategically located to offer ALS systems and services in all major North American basins.

The company also provides training around "Best Practices for Horizontal Shale Well on Rod Pump" workshops throughout the U.S. for its ALS customers, where operators and DNOW rod pump experts can discuss specific issues and solutions.

eLynx Technologies

The eLynx software suite enables improved oil and gas production through SCADA monitoring, operational intelligence and predictive analytics, according to the company. The company's SCADA monitoring services offer end-to-end security, field-hardened sensor and cloud communication networks, data normalization and custom user configurations.

eLynx's operational intelligence systems help users assess wells, identify production opportunities or high-priority issues, and focus on solving problems. Its predictive analytics operations offer digital twin monitoring and data analytics that can help improve production and cut costs by suggesting optimal well settings and forecasting looming problems in time to take action.

The company's operational intelligence site, used in addition to SCADA, delivers visibility, productivity and insight for production teams. It speeds decisions and sharpens insight for users in the oil field. eLynx's data scientists use SCADA readings to clarify what is happening downhole. Armed with clean data, eLynx's systems give engineers new insight into optimizing well operations and predicting future well behavior. The company's digital twin models can simulate and test a higher number of combinations of settings. As a result, users will discover simple ways to increase production quickly, usually at no additional cost.

During the second half of 2018, eLynx released two new products for the oil and gas industry. In November eLynx released a transformative predictive maintenance product "for the fast-growing electric submersible pump sector, with savings as high as $13,000 per month per well," according to a company press release. In September eLynx released its predictive analytics software-as-a-service product that is designed to identify production and equipment problems days before they become apparent.

In addition, in January 2019, eLynx announced a collaboration research agreement with the University of Tulsa to develop and validate digital twins to fully predict the behavior of wells produced using artificial lift, a company press release stated.

Emerson

Emerson offers artificial lift optimization software that constantly responds to constraints and changing well production compositions.

The company's Dynamic Lift Optimization (DLO) system automatically determines and controls set points of the lift system in real time. The lift optimization system enhances augmented static theoretical models and automatically operates lift systems at the most limiting set of constraints. It allows changes to be made to the system configuration when needed while distributing lift energy in real time to the wells that will benefit most.

In an example case of Emerson's DLO, a model of an offshore platform 15 years into its 25-year life span experienced a dramatic change in its water cut, which resulted in the platform's water handling system being at capacity. The system was optimized by placing actuators on each valve, allowing quicker test cycles through each of the seven wells. The test separator was replaced with a Roxar multiphase flowmeter, which allowed quicker testing of every well in sequence and on a daily basis. The result was quicker optimization and automation of well testing as well as a 4% to 14% improvement in production on the platform. That improvement would result in a 400-bbl/d to 1,400-bbl/d increase in production. For onshore operations, DLO contributes to improved production efficiencies as well as reducing lease operating expenses.

Endurance Lift Solutions

Endurance Lift Solutions provides technology-enabled solutions to help solve artificial lift challenges with its reciprocating rod lift and plunger lift, steel and fiberglass sucker rods, gas separators, capillary services and downhole gauges, artificial lift analytics and application design services.

Endurance offers full application design and optimization services in support of rod lift production. The company's Series 300 fiberglass sucker rods are designed for heavy load and high fluid volume applications plus corrosive environments, enabling increased production without upsizing surface equipment.

Rod lift products are tracked by the company's transparent equipment performance platform, Well Intel, which allows oil companies to track component-level run life, evaluate the performance of downhole metallurgy, query specific wellbore history and generate highly detailed reports at the click of a button.

The company's BLAZE metal surface treatment is highly resistant to abrasion, corrosion and mechanical wear through a substantial reduction in the surface coefficient of friction. Its process results in no changes to surface dimensions of the metal, and enhanced runlife and reduced downtime lead to fewer equipment changes and well interventions, according to case studies.

Additionally, Endurance Lift was formed through the acquisition of several artificial lift companies

Endurance Lift Solutions' Series 300 "High Flow" Fiberod features a hybrid wedge design and reduced cross-sectional area, leading to a 47% increase in flow area past the end fitting. *(Photo courtesy of Endurance Lift Solutions)*

during the recent oil price downturn. In addition to core artificial lift offerings, its team conducts in-house R&D, acquires emerging technologies in artificial lift and develops enhancements using out-of-industry technology with non-oilfield partners.

Endurance also offers onsite training courses to oil and gas executives, production engineers, consultants, production managers and field service technicians. Courses cover downhole pump components, application/design of a pump, specialty applications for gas and sand, animated examples of downhole conditions, and the API method of pump designation. The company offers these services through 25 field locations in the U.S.

Extreme Telematics Corp.

Private engineering firm Extreme Telematics Corp. (ETC) specializes in designing and manufacturing low-power, hazardous locations certified electronics for industrial applications.

ETC's plunger lift product line includes the Cyclops plunger arrival sensor, Sasquatch plunger velocity sensor, the ALiEn^2 plunger lift controller and the Iris wireless bridge.

Another ETC development, which tracks kinetic energy of plunger arrivals with Sasquatch, generates alarms on hard and dangerous impacts at surface. This helps producers use predictive maintenance to extend the lifespan of wellhead equipment, increase safety and reduce trips to the site, according to the company.

The business also offers electronic product design services for electronic hardware, firmware, mechanical, and test design and implementation.

Forland Services LLC

Forland Services provides pumping units and related services. Its products include conventional beam pumping units and long-stroke pumping units.

The company has developed a new generation of long-stroke pumping units that include a switched reluctance drive (SRD) and integrated control system. The units also feature a planetary gear box and open-looped chain/traveling sprocket transmission system, inner-tower counterweight system and a flexible load belt, according to the company's website. The control cabinet includes an integrated power supply, SRD/programmable logic controller unit, human machine interface module, physical indicators/buttons and an optional remote access module.

"The Forland long-stroke pumping unit can achieve independent upward and downward stroke speeds without a variable frequency drive. This is beneficial especially for heavy oil wells, horizontal wells and wells that are prone to gas lock," the company said. "Additionally, stroke lengths are automatically adjusted and the working region of the stroke can be customized with no sacrifice to production capacity."

In addition, Forland carries and can provide other oilfield equipment such as hydraulic disc brakes and automatic drillers. Standard and customized gear boxes and structural parts also are available.

Flowco Production Solutions

Flowco Production Solutions offers a full range of artificial lift services, including gas-lift and plunger lift systems.

Among the gas-lift services offered by Flowco are continuous flow gas lift, intermittent gas lift, cas-

ing (annular) flow, a packer bypass system (PBS), a micro-annulus crossover system and an increased annular velocity system. The PBS combines a conventional gas-lift system with a packer, which allows gas to travel through the packer.

The micro-annulus crossover system is offered in both horizontal and vertical systems. The horizontal micro-annulus system utilizes a crossover flow adapter and mini wellbore below the packer, a method that allows deeper point of gas injection compared to traditional gas-lift systems. The vertical micro-annulus system is an option for wells with low reservoir pressure where it is important to isolate gas-lift pressure from the perforations.

The company's plunger lift applications include traditional lifts and continuous flow plunger lifts. Flowco's line of plunger lifts includes the Rage bypass plunger, the Spin-Fury plunger and the Sure-Seal plunger. The plungers are suited for wells that recently have been completed, with sand and/or scale problems and for horizontal applications or deviated wells.

Global Production Solutions LLC

Global Production Solutions LLC's (GPS) artificial lift products and services include electric submersible pump (ESP) systems, jet pumping, well testing and repairs. In addition, the company's control and automation offerings for artificial lift include variable speed drives, motor controllers, switchboards and metering panels.

GPS developed a program to optimize water transfer and disposal costs. In testing, the company said it has reduced power usage by up to 50% while also reducing mechanical wear.

Additionally, the company's reciprocating ESP system consists of a modified conventional ball and seat pump driven by a reciprocating downhole motor, combined with specific variable speed drive technology. This unit can be applied where flow rates are below conventional ESP systems, have a high gas-liquid ratio and high dogleg severity, and/or in horizontally completed wells where traditional rod-driven systems are inefficient and ineffective, according to the company. The unit also can be applied in low-profile locations or where a small footprint is required.

GPS also has developed a proprietary algorithm to allow greater bottomhole pressure (BHP) drawdown while maximizing inflow potential as compared to conventional gas lift. The system extends the application to lower BHP wells that previously were not considered viable gas-lift candidates and were produced inefficiently through other forms of artificial lift.

Halliburton

Halliburton's artificial lift portfolio includes electric submersible pumps (ESP), horizontal pumping systems (HPS), progressive cavity pumps and 24/7 well monitoring. The company also provides artificial lift installation, application engineering and equipment design, reliability engineering, equipment testing and repair, well testing, and cable spooling and repair.

Summit ESP's holistic approach to well surveillance, backed with 24/7 monitoring services, is designed to increase production, improve runlife and reduce downtime and labor. *(Photo courtesy of Halliburton)*

Halliburton Artificial Lift provides customized solutions and ongoing support through real-time collaboration.

Summit ESP, a Halliburton service, provides integrated ESP technology and services that include Tiger Shark II pumps and Corsair motors as well as a wide range of products and services to meet ESP and HPS needs.

Halliburton's SandRight technology is a solids fallback preventer designed to deter damaging solids from entering an ESP during power shutdown events, preserving the ESP's life.

In addition, the DEVIATOR flange offers greater recovery of reserves by setting the ESP system closer to the pay zone. The tool's "design allows ESP systems to go deeper in the well and closer to the production zones, supporting stable well performance and lower operating costs," according to a product fact sheet.

Leistritz Advanced Technologies Corp.

Founded in 1905, Leistritz is a manufacturer of various engineered products for the process and energy markets. Based in Germany, the company offers pump, production, extrusion and turbine

This portable gas engine driven multiphase pump is designed to improve efficiencies. *(Photo courtesy of Leistritz)*

technology. Pump technologies include screw pumps, multiphase production systems and re-engineered pumps.

The company's screw pumps are designed to withstand high viscosity and temperature as well as tolerance for high gas entrainment. In addition, Leistritz's multiphase production systems are designed to lower gathering and wellhead pressure to supplement downhole pumps and are installed in onshore, offshore and subsea applications.

Leistritz also provides startup services, technical assistance, spare parts and repairs as well as technical training and onsite evaluations.

This year a global team called Leistritz Upstream Solutions was launched and focuses on new pump-based solutions to further improve oil and gas production.

Liberty Lift Solutions LLC

Liberty Lift provides artificial lift products including beam pumping units, long-stroke pumping units, gas-lift systems and hydraulic jet pump units.

Liberty Lift's HyRate technique is designed to address and improve gas-lift shortcomings and facilitates annular and tubing lift without a workover rig. The technique "incorporates an externally mounted assembly with both special capsule valve mandrels that allow annular flow and conventional mandrels permitting assisted tubing flow," according to the company. "The conversion from one lift method to another can be accomplished quickly and efficiently with the only use of a wireline to pull or replace the bottom tubing plug."

Liberty Lift also works with JJ Tech to offer hydraulic jet pump units that include a surface power fluid system, prime mover, surface pump and downhole jet pump.

Liberty Lift's EG Pumping Unit works in the Permian Basin. *(Photo courtesy of Liberty Lift Solutions LLC)*

In February the company opened an additional service center for installing and servicing artificial lift equipment. The new facility is located in Hobbs, N.M.

Lightning Production Services

Lightning Production Services (LPS) manufactures continuous rod and lined tubing to reduce the frequency of failures in deviated wellbores. These products, along with LPS field services, have been shown to eliminate holes in tubing and rod parts, resulting in reduced failure rates and increased profitability in challenging environments, according to the company.

The company's LightningRod continuous rod eliminates all the couplings in the rod string for the top and bottom connections. Eliminating the couplings distributes the side loading between the rods and the tubing along the entire wellbore, reducing the overall impact of deviation. This reduction in the effective side loading leads to longer run lives for both the rod and the tubing strings.

LPS' LightningFlo thermoplastic tubular lining is mechanically bonded to the inside diameter of the tubing and can be installed inside of both new and used tubing. The lining provides protection from frictional wear and the corrosive effects of the caustic downhole environment. LightningFlo lined tubing has been shown to extend run times by up to five times in certain applications, according to the company.

The company's service offerings include maintenance and repairs on wells with conventional or continuous sucker rod and other types of artificial lift. The company also provides pump changes, broken rod maintenance, pulls and flushes, polish rod changes, packing or stuffing box changes, drive head maintenance, and fishing services.

Materion

Materion's ToughMet 3 Sucker Rod Couplings for shale wells operate on an artificial lift rod pump. The couplings help eliminate production interruptions caused by sucker rod coupling and production tubing failures in deviated sections of wells. The couplings resist galling, mechanical wear, thread damage, corrosion and erosion.

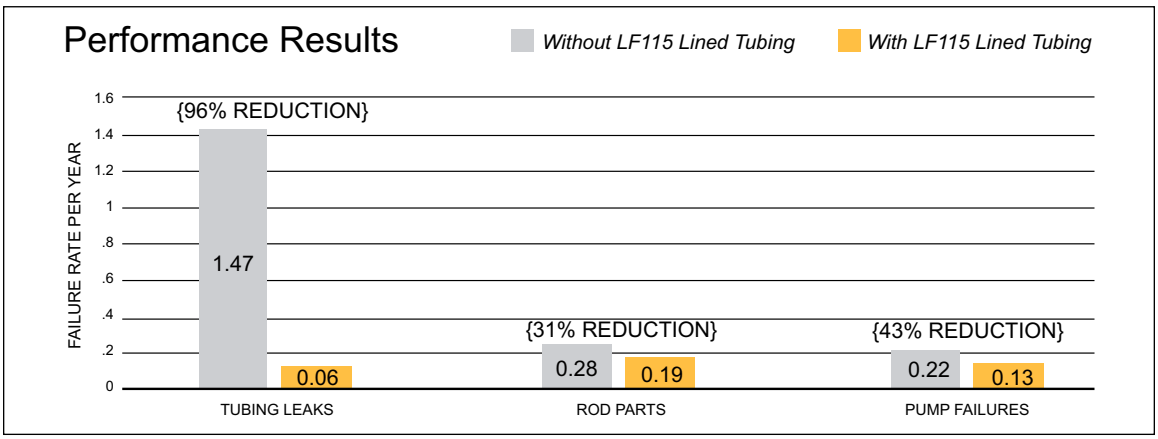
Materion's ToughMet 3 alloys were originally engineered for drilling applications and have more than 30 years of use in directional drilling tools and other oilfield equipment components, such as electric submersible pump motor bearings, according to the company. The copper-nickel-tin alloys are spinodally hardened to provide attributes beyond those typically found in high-strength copper alloys. Those attributes include high impact and fatigue strength; corrosion, erosion and wear resistance in most oilfield environments; control fluid compatibility; magnetic transparency; and anti-friction and anti-galling characteristics. ToughMet 3 alloys resist hydrogen embrittlement, chloride stress corrosion cracking and moderate H_2S environments.

A full range of ToughMet couplings are available from local inventories for immediate delivery, including sucker rod couplings, cross-over couplings, polished rod couplings and the company's new valve rod guide bushing coupling.

National Oilwell Varco

Artificial lift technologies provided by National Oilwell Varco (NOV) include rod pumping systems, progressing cavity pump (PCP) systems, tubing and rod wear prevention equipment, production service hookup equipment, and automation.

NOV's rod pump system includes hydraulic pumping units that are designed to have a smaller



This chart depicts the case study results when LightningFlo was used in the Permian Basin on 13 wells. *(Image courtesy of Lightning Production Services)*

NOV's production service hookup is designed to achieve better pressure control to maximize production and minimize downtime. *(Photo courtesy of NOV)*

footprint and quick installation, while increasing personnel safety and improving control over oil and gas production. The company provides a full suite of production service hookup equipment for rod pumping and PCP applications, with design focused on achieving better pressure control while maximizing production and minimizing downtime. Additionally, NOV's Universal Wellhead supports the entire life of the well as it transitions from one form of artificial lift to another.

The company's PCP system is designed for use in both oil production and dewatering applications. A PCP controller, part of NOV's line of automation products, ensures greater operational efficiency and better control of PCP artificial lift systems. It integrates into existing networks to simultaneously monitor pump performance and control on/off cycles. The system minimizes downtime and optimizes well performance by automatically changing pump speed.

Novomet

Russia-based Novomet manufactures electric submersible pump (ESP) systems. The company's technology includes slimline ESPs capable of fitting inside of 4-in. casing; PowerSave ESP systems to reduce power consumption by up to 50%; products for wells with high gas-oil ratios, scale, solids and H_2S; and a rotary displacement pump for high-viscosity fluids.

The company's ESP offerings include downhole equipment, surface equipment, and scale preventers and filters. Other artificial lift products include gas-handling, scale and solids management and extreme H_2S environment solutions. Novomet also offers a rigless ESP system, a bypass (Y-tool) system, a progressing cavity pump with topside and downhole motors, and surface pumping.

Novomet developed the Colibri cable-deployed ESP system to eliminate the cost, complication and time required to mobilize rigs. ESP installation, maintenance and repair can all be carried out using a simple crane and cable, helping operators put their wells back on production sooner and reducing overall lifting costs. *(Photo courtesy of Novomet)*

In March 2018 Novomet developed an abrasion-resistant ESP system with an expanded operating range, according to a news release. "Due to the expanded operating range, it is now possible to reduce the standard range of 362 and 406 series ESP systems with flowrates from 10 to 350 sq m/d from 13 to 3 models. In addition, ImpalaESP is designed to operate at 3,000 rpm and may be driven by an induction motor with a conventional VSD," according to the press release. "As a result, operators will be able to reduce inventory levels, optimize the ESP application process and ultimately cut total costs of oil production."

In July 2018, the company announced that pilot operations of its 400-hp 406 series permanent magnet motor were successfully conducted at the Mamontovskoye oil field by Rosneft Yuganskneftegaz in February and May last year. The motor "completely confirmed its energy efficiency. The power consumption was lower by 13% in contrast to an asynchronous motor," a press release stated. "This innovative development enabled the increase of head in the 406 series up to 11,500 ft (2012 bbl/d) and 9,840 ft (3,145 bbl/d), thereby replacing imported ESP systems with similar head and capacity."

In September 2018, the company released a new product line of gas separators for trial operations. The separator offers reduced weight and consumes up to two times less energy, a press release stated.

Novomet has service centers in 12 countries outside of Russia. The centers offer a variety of ESP services for well maintenance that include sizing, inspection, transportation, assembling/disassembling, testing and supervising.

Petroleum Technology Co.

Petroleum Technology Co. offers wellhead, gas-lift, chemical injection and other completion solutions.

PTC boasts its NexLift series of side-pocket mandrels (SPMs) are the only single-piece unwelded SPMs in the industry. "As no welding is used during the manufacturing process, NexLift SI and NexLift SI-B mandrels can be manufactured from alloys that have traditionally not been used due to poor weldability, reducing the costs of the SPMs," the company stated on its website. "PTC's NexLift SI-B mandrel also protects the production casing from potentially harmful fluids and pressure."

In addition, PTC's GoLift thru-tubing gas-lift straddle system is designed to offer a cost-effective alternative to workovers where there is a need to retrofit new or upgrade existing gas-lift or chemical injection systems, without compromising well integrity, the company said.

Priority Artificial Lift Services LLC

Priority Artificial Lift Services offerings include gas-lift, plunger and completion tools and technologies. The company's services include equipment installation, production optimization, troubleshooting, production analysis, nodal analysis, well modeling, consulting, engineering, training and manufacturing.

The company uses its conventional high-pressure gas-lift equipment (rated to 10,000 psi) to accommodate gas-lift installations on initial completions and in highly developed areas where high-pressure offset fractures are likely. As the wells deplete, Priority has a variety of gas-lift products to accommodate installation of gas-lift valves deeper into the wellbore to maximize production. Typically, the deeper gas-lift system is accompanied with a plunger to create a hybrid gas-lift and plunger lift system. This hybrid system is designed to reduce flowing bottomhole pressure and increase gas-lift efficiency.

Priority has nine service locations and a manufacturing facility in the U.S.

Rockwell Automation

The Rockwell Automation OptiLift artificial lift system provides end-to-end smart field operations to oil and gas operators globally. The OptiLift Intelligent Net Oil Computer (iNOC) is an engineered system that offers remote connectivity, enhanced visualization, optimized test capacity and improved test duration. The iNOC system is part of a fully connected oil field. The iNOC system improves well

The Rockwell Automation intelligent artificial lift systems help oil and gas companies gain better visibility into their operations, optimize production and asset performance, and reduce operating costs. *(Image courtesy of Rockwell Automation)*

test duration with oil and water volume prediction for 24 hours during any test period. The system installs in the "liquid leg" of a two-phase test separator and can support tests on up to seven wells. The OptiLift rod pump controller is engineered to help maximize return on investment and achieve sustainable operations and operational excellence. This on-site controller can help provide the accurate and flexible control necessary for well production optimization. The control technology also can be packaged with an Allen-Bradley variable frequency drive to create an integrated system for speed control in rod pump applications. The OptiLift virtual flowmeter is designed to optimize production and reduce costs. Engineers are able to view the pressure, temperature and flow rates in real time, which enable them to adapt quickly to uncertain situations. These systems form part of the broader ConnectedProduction system, which has been designed to visualize and optimize onshore oil and gas production from wellhead to point of transfer.

Schlumberger

Schlumberger's artificial lift offerings include electric submersible pumps (ESP), gas lift, horizontal surface pumps, sucker rod pumping units, progressive cavity pumps (PCPs), production lifting services and real-time monitoring and optimization. The company offers integrated, field-proven lift platforms that include REDA ESP systems, Camco gas-lift valves, Don-Nan sucker rod pump units and KUDU PCP systems, to name a few.

These platforms are kept in optimal operating condition by the Schlumberger Lift IQ production life-cycle management service, which offers monitoring, diagnostics and optimization of artificial lift systems in real time. The Lift IQ service taps into the engineering, manufacturing and surveillance expertise of Schlumberger with access to global service centers 24/7 year-round, according to the company.

The Schlumberger LiftSelect strategic production planning service simplifies the process of selecting the artificial lift strategy that will best achieve production goals, based on objective analysis of economic and technical criteria. The service uses available field and reservoir data to model well behavior and maximize asset value by reducing the cost per barrel of hydrocarbon production.

Because the lift system is an integral part of the completion, Schlumberger and Production Plus Energy Services formed a joint venture to develop the HEAL horizontal enhanced artificial lift system, which bridges that connection to help ensure optimal well productivity. The HEAL system conditions the produced fluid stream, mitigating slug flow to extend natural flow and increase productivity over the life of the well.

The HEAL horizontal enhanced artificial lift system conditions the produced fluid stream, mitigating slug flow to extend natural flow and increase productivity over the life of the well. *(Source: Schlumberger)*

Sercel-GRC

Sercel-GRC provides downhole pressure and temperature gauges for artificial lift and permanent monitoring markets worldwide. The company's artificial lift products service electric submersible pumps (ESPs) and progressive cavity pumps as well as gas-lift, sucker rod pump and jet pump applications.

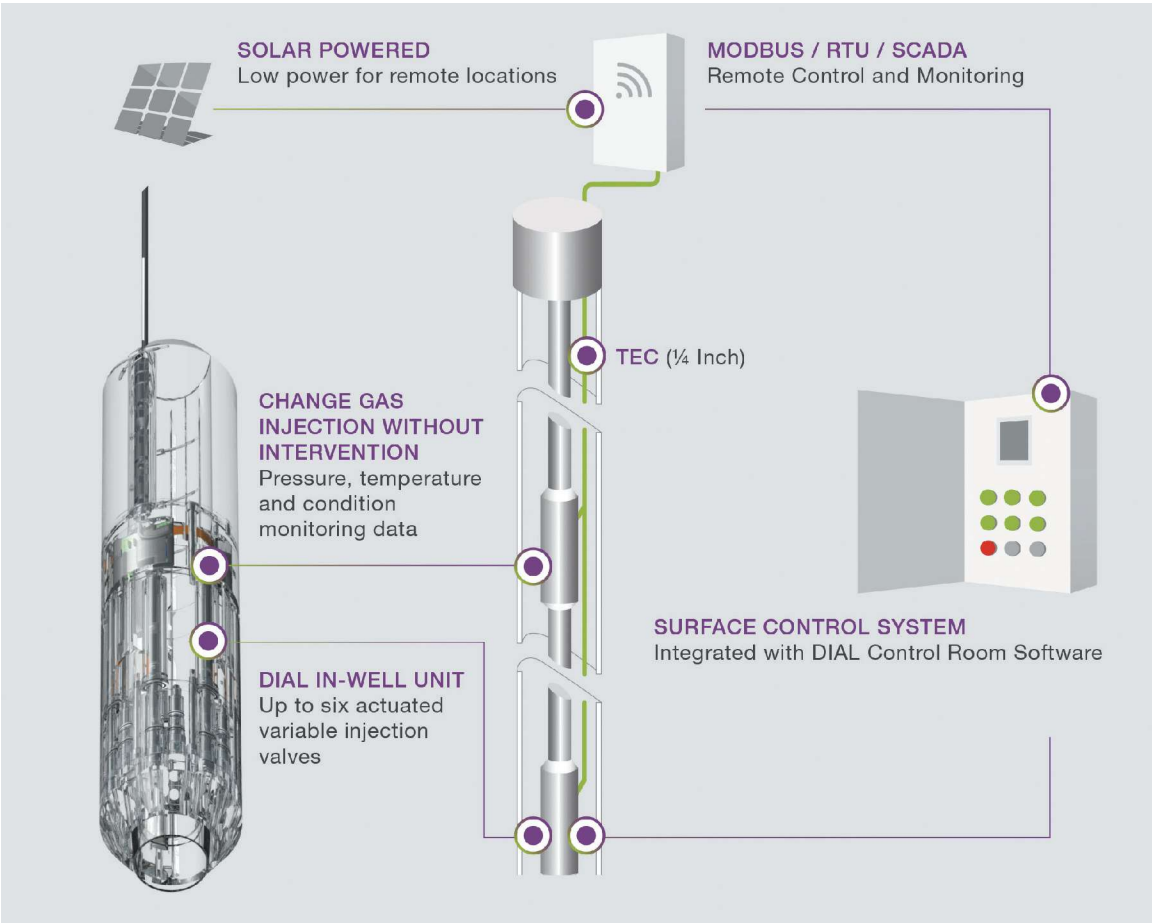
Spy Pro is the only ESP gauge available with a waterproof, metal-to-metal sealed design. *(Image courtesy of Sercel-GRC)*

Sercel-GRC's Spy Pro waterproof ESP gauge is designed to let users continue monitoring well performance when the motor connection is submerged in water, resulting in unbroken access to vital data needed.

In addition, the company's Data Pro universal datalogger is a high-performance configurable surface acquisition unit that features datalogging, real-time graphing, historical graphing, Modbus communication and gauge configuration.

Silverwell

Silverwell's Digital Intelligent Artificial Lift (DIAL) production optimization system addresses the challenge of gas-lifted wells operating in a nonoptimal state. The DIAL system allows gas-lift injection rates and depths to be adjusted and monitored in real time downhole. The system is fully digital and electronically controlled and monitored from the surface via a tubing encapsulated cable. It replaces conventional gas-lift mandrels and valves with permanently installed in-well DIAL units. This eliminates wireline interventions and workovers to adjust gas-lift injection rates and depths, along with the associated operational risk, costs and production deferment, according to the company. Silverwell can configure the DIAL system onshore or offshore to suit all gas-lift completion architectures—conventional single string, dual string, *in situ*, intermittent and annular flow. The DIAL in-well unit features up to six injection orifices, each individually controlled from the surface providing multiple available injection rates. When combined with annulus and tubing pressure and temperature sensing capability at each DIAL station, the operator can implement data-driven optimization strategies as well or operating conditions change without incurring the risk and cost of intervention. DIAL overcomes the limitations of existing production and completion equipment, eliminates well intervention and enables an economically enhanced approach to gas-lift production optimization, according to the company.



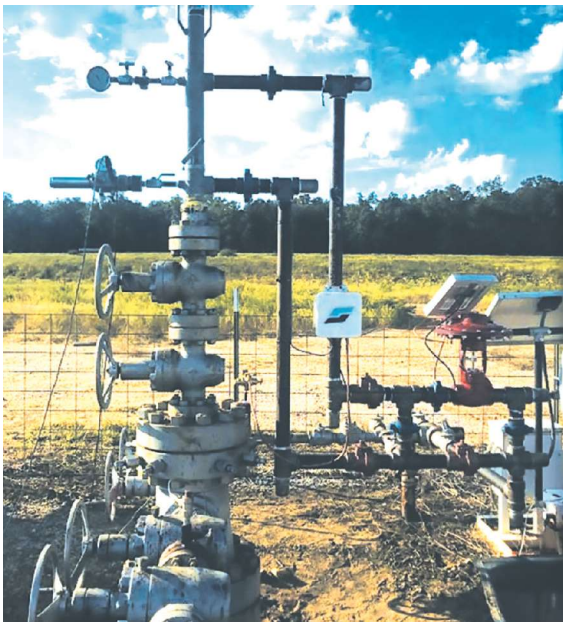
Multiple DIAL in-well units are installed in multidrop configurations to provide variable injection rate and depth via local and/or remote monitoring and control. *(Image courtesy of Silverwell)*

Superior Energy Services

Superior Energy Services offers drilling products and services, onshore completion and workover services, production services and technical solutions. Superior's Gas Lift division includes onshore and offshore gas-lift equipment. The company provides fit-for-purpose artificial lift offerings through its engineering, optimization and troubleshooting techniques, manufacturing and value-added approach.

Superior offers gas-lift design, troubleshooting and optimization classes in the field and in the office for engineers, pumpers and interns.

The plunger lift group works alongside the gas-lift group to offer plunger lift as well as gas-lift-assisted plunger lift systems. Superior's plunger lift group manufactures lubricators with ratings of 3,000 up to 15,000; a multitude of plungers, most notably being the dart-style plunger and the Pacemaker plunger; and an assortment of bottomhole assemblies including multistage offerings. The manufacturing team uses well modeling software, 3-D printing and computational fluid dynamics to provide technical solutions. The plunger lift field team provides technical training on site including well model and optimization classes as well as using echometers in the field. With the ability to couple the gas-lift and plunger lift systems in one gas-lift-assisted plunger lift, Superior can offer an artificial lift tool for the life of almost any well.



A sales technician installed a plunger system featuring Superior's new robust lubricator and basic controller box, and ECHO Meter tracked the plunger as part of the company's optimization process. *(Photo courtesy of Superior Energy Services)*

Tally Energy Services

Tally Energy Services is a private-equity backed firm with a buy-and-build strategy in specialized North American shale products and services. The company is focused on directional drilling, completion equipment and artificial lift.

Tally Energy Services offers artificial lift services via its partner, Tech-Flo Consulting LLC, which Tally acquired in 2017. Tech-Flo, an artificial lift solutions and production equipment company, provides hydraulic lift systems, jet pumps, triplex pumps, separators, equipment packaging and pump maintenance.

On March 1, Tally Energy Services acquired Epic Lift Systems, a portfolio company of Intervale Capital. Epic Lift Systems is a provider of plunger lift, gas lift and complementary compression solutions. "The acquisition establishes Tally as a major provider of artificial lift services in the U.S. with extensive field service, applications engineering, product development and manufacturing capabilities," a company press release stated.

Tenaris

Tenaris, a supplier of tubes and related services for the world's energy industry, has 50 years of experience in the manufacture of products for artificial lift systems. The company has manufacturing facilities in 18 countries with plants in Argentina, Brazil, Mexico, Romania and the U.S. In July Tenaris will open its sucker rods manufacturing plant in Conroe, Texas, to serve U.S. customers in their artificial lift systems operations. The $70 million investment is equipped with advanced technologies to optimize efficiencies and reduce production times. The new rods mill has the capability to manufacture BlueRod premium sucker rods and X-Torque rods as well as the entire range of API sucker rods for beam and progressive cavity pumping.

In December 2018, Tenaris inaugurated a service center in Midland, Texas, to support its sucker rods product segment with the storage, preparation and delivery of rods. The facility includes equipment on site to inject guides of various sizes onto the rods, including the new high-performance rod guide Ten-Flow and the Helix guiding solution.

Tenaris' AlphaRod sucker rod series features rods manufactured with enhanced steel grades that are designed for a long life in demanding requirements. The AlphaRod series includes two steel grades, which cover a wide range of applications. The AlphaRod HS (high strength) and AlphaRod CS (critical service) are designed to handle increased

Tenaris will open its new sucker rods manufacturing facility in Conroe, Texas, in July. *(Photo courtesy of Tenaris)*

service loads and overcome fatigue and corrosion-fatigue problems in beam pumping and progressive cavity pumping applications.

Valiant Artificial Lift Solutions

Valiant Artificial Lift Solutions is an independent oilfield service company specializing in downhole and surface pumping solutions that include electric submersible pump (ESP) and horizontal pump systems (HPS). Valiant's product line also includes Pulse variable speed drives (VSDs), which provide automation and control capabilities for ESP and horizontal pump system applications and feature a 7-in. color touchscreen interface for user programming. Valiant's technical offering is paired with services ranging from application engineering and equipment sizing to well monitoring and performance analysis.

In May 2018, Valiant and Weatherford entered a memorandum of understanding to jointly commercialize ESP and horizontal pump systems in specific international markets under the co-brand Weatherford, Powered By Valiant.

The company's ESP systems support flow rates up to 35,500 bbl/d and can be customized for production in abrasive or high gas content applications. Specifically, Valiant's Intercept suite of gas solutions includes standard and inverted shrouds, gas separators, helico-axial stage designs for fluid conditioning and proprietary VSD gas-lock prevention software to help operators avoid, separate, process and control gas for improved ESP operation.

Valiant's Aquarius horizontal pump systems, available in surface and trailer-mounted configurations, are designed to produce up to 49,200 bbl/d (1,435.2 gal/min) at speeds up to 1,500 hp for surface pumping applications. Aquarius systems can incorporate monitoring and control options including pressure, temperature, vibration, flowmeters and backpressure controls, and a modular skid configuration provides resizing and customization capabilities.

Valiant's primary manufacturing and service centers are located in Midland, Texas; Norman, Okla.; and Bogotá, Colombia. These facilities provide equipment testing and assembly capabilities; dismantle, inspection and failure analysis; and field service support such as equipment installation, operation, maintenance and repair.

Veretek

Veretek provides its uniquely designed rotor and stator V-Pump to replace conventional electric submersible pump (ESP) centrifugal systems in wells with large amounts of sand and/or gas.

The company's focus is on multiphase conditions in unconventional wells where use of the V-Pump is designed to lead to fewer well interventions, longer run times, broader operating range and greater

Veretek's rotor/stator pump design targets multiphase wells. *(Image courtesy of Veretek)*

uptime by continuing to pump through multiphase conditions. ESP auxiliary equipment, such as gas separators, sand guards and sand screens, are not needed or recommended with the V-Pump. Also, it is operational with any service provider's conventional ESP motor, seal, cable and sensor configuration. According to the company, the V-Pump's operating characteristics offer a much greater speed range and more synergistic benefits with permanent magnet motors than conventional ESPs. In addition, the pump's design can be used with high-viscosity oil and can be reversed to flush the pump.

In multiple case studies of wells with extremely high amounts of sand in the Permian Basin, the V-Pump has lasted for several months where ESPs failed in just a few weeks in the same wells.

To date, there have more than 270 installations of the V-Pump.

Weatherford

Weatherford provides products and services for every form of artificial lift from reciprocating rod lift to progressing cavity pumping. As an end-to-end production solutions provider, the company also provides production optimization hardware, sensors, software and automation technologies.

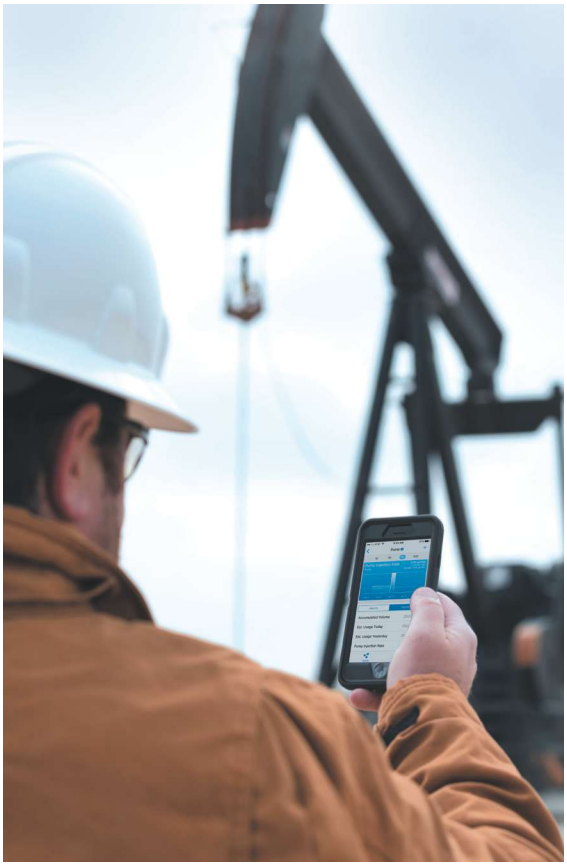
The company's WellPilot ONE universal controller centralizes management of all oilfield equipment to a single piece of hardware. This next-generation controller/remote terminal unit provides automation for the entire field and enables seamless transitions throughout all production and lift phases, which significantly reduces the total cost of ownership.

Another artificial lift technology is the sand-tolerant pump (STP), an alternative to standard rod pumps in wells with high sand production. The STP can perform in temperatures up to 182 C (360 F) and has a self-cleaning slippage-fluid filter to keep damaging sand out of the plunger-barrel sealing surfaces.

In addition, with couplings only at the top and bottom of the rod string, Weatherford COROD continuous rod minimizes the potential for rodstring failures and costly interventions, according to the company's website.

WellAware

WellAware provides Industrial Internet of Things (IIoT) production management and chemical management systems designed to help E&P companies capture and use their data for peak operating efficiency. The company's offerings include



A field technician uses the WellAware mobile app to determine the overall performance and levels of the various assets. *(Photo courtesy of WellAware)*

data collection, exception-based monitoring and actionable insights.

WellAware's platform captures critical production data and visualizes it in a meaningful way with an online analytics tool that prioritizes action. The company's native iOS and Android apps work without cellular connectivity and are used to configure and view real-time data in the field. Data captured include pressure, temperature, level, flow and electronic flowmeter/remote terminal unit production data within hazardous environments. The system's management operations allow user-configurable grouping of assets as well as list- and map-based visualization of real-time assets and configurable alarms. The mobile app enables rapid alarm acknowledgement, troubleshooting solutions and resolution.

WellAware's analytical capabilities include role-based dashboards for field personnel, engineers and executives, along with customized reports without IT or vendor assistance. WellAware offers a full-featured REST API to allow third-party applications to read data directly from the WellAware application infrastructure.

The company's IIoT system's capabilities include full-stack data intelligence, eliminating the need to deal with separate vendors for network, automation and software. WellAware reported that after implementation of its management system, a major E&P company reported reducing downtime by 75% to 80% and improving operating efficiency by more than 50%.

Zedi Inc.

Zedi is a technology and services company offering increased oil and gas production with software, automation, artificial lift, measurement, laboratory and field solutions.

The Zedi SilverJack artificial lift system is an advanced hydraulic pumpjack with an optimization controller combined with Zedi Access, a cloud-based data management system that provides remote monitoring, alarming and control.

Zedi's artificial intelligence and machine learning capabilities paired with Zedi artificial lift solutions have achieved an autonomous optimization functionality to improve bottom line results, according to the company's website. Users can have access to a real-time view of every field asset, high-resolution data and two-way communication for precise monitoring and control of assets. ■

Artificial intelligence and machine learning capabilities are paired with Zedi's artificial lift solutions. *(Photo courtesy of Zedi)*

Artificial Lift Technology Targets Efficiency, Flexibility, Lower Costs

Advances in artificial lift are redesigning conventional technologies to solve problems in long horizontal laterals and offshore wells.

By Scott Weeden
Contributing Editor

There are challenges facing the industry for artificial lift as operators are producing from deeper and higher temperture productions zones whether onshore or offshore. Drilling long lateral sections helps operators maximize contact with the producing formations, but undulations in the wellbore can create peaks and valleys that introduce new problems for the downhole equipment. The Bakken and Permian are examples of deep vertical sections with a sharp bend into the horizontal leg.

As Robert de Long, technology director with Summit ESP, a Halliburton service, described the wells, vertical sections are not very straight and the horizontal legs in many cases are intentionally crooked to touch more of the reservoir.

"No matter what type of artificial lift system you put in the hole, whether it is gas lift, electrical submersible pumps (ESPs) or progressive cavity pumps (PCPs)—everything except plungers—they don't like the undulations. These undulations in the horizontal legs cause a significant amount of slugging," he said.

Lou Martensen, product line director for Valiant Artificial Lift Solutions, pointed to brownouts as a significant challenge for producers with artificial-lift-driven wells. Brownouts occur when incoming voltage drops below a certain threshold, which not only affects the transmission required to run compressors and pipelines, but also disrupts the incoming power to variable speed drives that keep an ESP running.

Even momentary brownouts can cause the system to shut down, resulting in lost production and other problems for downhole equipment, he explained. These events have a reverberating impact on operators as well as all electricity users in the area, he continued.

Much of the technology around artificial lift systems has been around for a while. One such technology is permanent magnet motors (PMMs) for ESPs. The technology, widely used in Russia, is now gaining traction in U.S. shale plays, noted Lorne Simmons, vice president of planning, sales, marketing and business development for Borets US.

"The historical induction motor has been the historical workhorse for many years. Right now there is growing interest in the U.S. marketplace for PMMs," he said.

A new variation on annular and tubing flow gas-lift systems has been designed by Liberty Lift Solutions. The patent-pending technology allows an operator to switch back and forth between annular and tubing gas lift without pulling the tubing on the well. "For the transition from annular to tubing lift or vice versa, we can tell you almost the exact time that you need to switch based on our nodal analysis calculations," said Garrett Archa, gas-lift product line manager for Liberty Lift Solutions.

"An operator in the Permian Basin went from annular to tubing lift and they switched the production on the well and within four hours they were producing back up the tubing at the same production rates as the well was making flowing up the annulus," he said.

Reducing high ESP intervention costs and reducing production downtime is a major driving force for operators utilizing ESPs. David Malone, CEO and president of AccessESP, said that his company is in the rig-elimination and reducing production downtime business. "Everything we do is offshore or in remote locations. It is in places where rig access is difficult and expensive, and there is a lot of lost production with ESP downtime. It is offshore and in West Africa, the Middle East and Alaska."

As an example, operators in offshore West Africa have small platforms and have to bring in a jackup rig or hydraulic workover unit for replacing ESPs. Many operators wait for two or three ESPs to fail before they can economically justify a workover program.

"We just did a program where the first ESP that went down was offline for almost 24 months. They lost 24 months of production waiting for two more ESPs to die. Total workover costs to bring a rig on site to swap these ESPs was over $10 million," Malone explained. "By changing the ESP thru-tubing and on slickline, AccessESP can mobilize its equipment on the platform—without the need for a jackup or workover unit—and do a live-well swap using only slickline. The typical intervention savings and value of added production we see when we put in our systems is on the order of $2 to $5 per barrel."

It is not just old technology that is new again; there is a lot of new technology coming into the artificial lift market as well. John Morgan, vice president and general manager of production oil and gas Internet of Things (IoT) for WellAware, noted that one of the company's challenges has been "helping customers to understand the benefits of implementing the Industrial Internet of Things [IIoT], not only for improving their operational efficiency but also for opening other business models for the companies internally."

The applications that WellAware has mapped are known as micro-verticals and are different applications on the wellpads and pipelines. The company looks at the ecosystem to understand applications for monitoring and controlling IIoT devices, according to Morgan.

More detailed explanations of the challenges and solutions for artificial lift systems follow.

Dealing with gas slugging

"For the majority of horizontal wells, we're dealing with very high quantities of liquid—oil and water—and very, very high quantities of gas. Some of these wells have produced several million cubic feet of gas per day while we're pumping oil and water out of the well," Halliburton's de Long said. "We have to have an ESP system that will handle the significant volume of gas along with the high volumes of liquids."

The undulations in the horizontal laterals cause a significant amount of slugging. Gas caps build up in the high points of the casing, which effectively block the fluid or liquid flow until there is enough pressure behind the cap to push the gas slug. In turn that causes a very high velocity fluid surge that carries solids with it. The gas slug itself actually stops any kind of pumping system, disrupting the pumping mechanism, with the exception of plunger lift, he explained.

"We've developed numerous pump stages that are specifically designed in quasi-axial flow arrangement to allow us to pump high volumes of gas without gas slugging. Gas gets in there and shuts off operation of the pump. We can get into a well that has 70% to 90% free gas at the pump intake and still manage to produce that well. We do that through various mechanisms of self-orienting intakes that allow gas to pass by the equipment," de Long said.

"One of the biggest problems that ESP systems have in unconventional wells is because of intermittent flow due to slugging. The ESP system, particularly the pump, will get extremely hot very, very quickly when it gets into a gas-slug situation. The hardened bearings will come loose, shatter or fall out, which is pretty disastrous for the pump," de Long said.

"We have developed a mechanism for locking the bearing assemblies inside the pump to allow the pump to go through extreme excursions without having a bearing failure."

It is a simple idea using a mechanical and an elastomeric locking mechanism in the bearing itself to keep them in place, he added.

The company has gas separators, gas-handling pumps and fluid conditioners to get the multiphase fluid stream into the ESP, compress it, put it through the pump and up to the surface.

The length of the lateral doesn't make much difference but the crookedness of it and the tendency for larger and longer duration slug flow coming through that causes problems. "There are mechanisms that are being developed and deployed in some areas of the world that will actually equalize the flow across that horizontal section and stabilize some of the flow that turns to slugging. That is being employed to take care of the long, crooked sections," he noted.

As de Long pointed out, Halliburton's focus is primarily on ESPs at this point. "From our perspective we are dealing with high-volume production systems. Production rates can be anywhere from 200 to 300 barrels per day up to several thousand

Halliburton engineers at Summit ESP Research and Technology Center can validate theory by creating harsh environments to aggressively test every component of an ESP system before ever going out into the field. *(Photo courtesy of Halliburton)*

barrels per day. We have to have an ESP system that will handle a significant volume of gas along with the high volumes of liquids."

Halliburton has stages designed specifically to handle a very wide operating range. "We sacrifice a little bit of the absolute, highest efficiency point to expand the operating range. We do that because these wells start out at 2,000 barrels per day and six months to a year later the wells are 200 barrels per day. We want to be able to handle those extreme ranges with a single pump so we don't have to have a rig come in, pull the unit and replace it with a different size," he explained.

The company focuses on putting a pump in the hole that can be left there for long periods of time. "It is not uncommon to have an ESP system run 10 to 15 years. We put a lot of engineering into making sure that we are able to get those extremely long run times. The way we do that is match the hydraulic performance of the pump, the mechanical components, the bearing systems, corrosion resistance, sand resistance and gas-handling capabilities. We make sure the equipment is matched for the conditions in that well," he said.

"What I've done over the past 10 years was spend a considerable amount of time with guys doing well layout and profile that will actually suit their long-term artificial lift needs. It is probably one of the single biggest factors relating to the success of a long-term artificial lift program. It is not the pump you put in the hole; it is the well plan you're forced to live with," de Long emphasized.

Mitigating power brownouts

With regard to ESPs as well as other types of pumping systems, one of the biggest problems in regions across the globe is electrical brownouts, or a situation where the grid's voltage output momentarily drops. As residential and commercial demand for electricity continues to stress the grid's transmission capacity, an electricity bottleneck is creating significant challenges for oil and gas operators in places like Texas and Colorado.

"What I am referring to is that we expect to see the voltage coming into a drive at 480 volts. In a place where operators have equipment hooked into the grid, such as variable speed drives, it draws from the transmission capacity on location and that 480 volts drops to 450 volts. The incoming voltage may only drop for three seconds or so below the voltage threshold, but the ESP shuts down," he said.

When that happens, the operator has to time it out and restart. Usually that takes one to two hours, although it could be a 24-hour shutdown in cases where a pumper has to go out and manually restart. Most of the time, Valiant ESPs are programmed to automatically attempt to restart in the case of a shutdown.

"Flowback through the production tubing puts all that sand back in the pump. Without a sand barrier device, the ESP could twist a shaft on startup. Ultimately, you would have a failure with the ESP that really had nothing to do with the equipment—it was caused by the incoming power," Martensen explained.

"Operators have a lot riding on their ability to use electricity to power their equipment. Because it's a lot less expensive to run on electricity than diesel, for example, ensuring adequate power supply to these wells is key to supporting their production and improving operating margins," he added.

The industry has provided technology that's effective in riding through nanosecond brownouts for certain applications. However, there are times when a dip in voltage extends beyond the capabilities of technology currently deployed. What service providers like Valiant are working toward is achieving a three- to five-second ride through.

"To make sure our customers with drives on a wellsite aren't at risk of having their operations stalled, Valiant is in the process of testing different technologies with customers who are looking to partner with these solutions," Martensen said.

"One option we're looking at is a technology designed to supply stored power during a brief voltage drop. Like an oversized battery pack, this technology could kick in during a brownout to allow the drive to ride through a drop in voltage without shutting down the ESP. Our No. 1 priority is to help our customers overcome these types of production hurdles as safely and effectively as possible," he noted.

"What really ties these solutions together is our ability to monitor our customers' downhole equipment and analyze historical data on each well in the field through Valiant's tracking database," Martensen explained.

Collecting this information company-wide allows Valiant to draw trend analysis and determine the best preemptive and corrective actions to optimize well performance and avoid shutdowns.

"This could mean programming the drive to operate under transient conditions or resizing the ESP to adapt to changes in production over time. By combining the field experience and insights of our people with these digital tools, we are able to offer solutions that address operators' problems before they occur," he said.

Permanent magnet motors

Borets introduced its first permanent magnet motor in 2006. PMMs for ESPs predominantly have been used in the Russian market. Borets has shipped, sold or installed over 12,000 PMMs for ESPs globally. Currently there are over 4,000 PMMs in operation in Russia and roughly 75 operating in the Permian Basin," said Borets' Simmons. "This proven technology is finally gaining a foothold in U.S. markets."

One of the key constituent parts of the PMM is the internal rotor section. It doesn't need any induced current to create a magnetic field. That field comes from the permanent magnets. "In contrast to an induction motor, there is no current induced in the rotor. That in itself is where the prime electrical efficiency comes from because you don't have copper bars that suffer from electrical losses, and you don't generate the same amount of heat," he explained. "You instantly achieve about a 10% power efficiency."

Valiant Pulse Variable Speed Drives utilize the electrical grid to power multiple ESPs on a wellsite in the Permian. *(Photo courtesy of Valiant Artificial Lift Solutions)*

Controlling PMMs for an ESP application is not trivial. Borets developed a proprietary algorithm for vector-loop control of a PMM. "I would point out that variable-speed drives that can control PMMs are not all equal," Simmons said.

There are three types of permanent magnet control algorithm used by the industry. The first is a very simplistic back electromotive force (EMF) method, which doesn't yield optimum efficiency. It measures rotor flux on the idle phase current that's applied to the stator, he noted.

The second is a scalar control method. While it is a little more complex than back EMF, it basically works to maintain a constant ratio of voltage and frequency. It can optimize motor control but only for a static downhole load. With any kind of variable load, this method won't achieve optimal efficiency.

The third method is vector-loop control, which works mathematically through an algorithm running on a high-speed processor in the drive. It resolves two vector components or components of the current, which can be considered to be one as the magnetizing current and the other as a torque current, Simmons explained.

The Borets team deploys a Permanent Magnet Motor ESP system in the Permian Basin. *(Photo courtesy of Borets)*

"That allows the drive to optimize the amount of current that is applied to the stator through continuously changing load conditions. It is superior in how it controls the permanent magnet rotor and results in maximum system energy efficiency," he said. "In the past few months at our facility in Tulsa, we've doing a lot of testing of PMMs with drives from manufacturers that just make variable-speed drives. We test them with the same size motor for consistent comparison. We see differences in the performance and efficiency numbers."

One of the obstacles to wider adoption of PMMs has been that these require a compatible drive to operate. "If an operator has a field full of drives that can only control induction motors, and they then want to start using PMMs, it will require a different drive to operate it. They're like, hang on I've got all these other drives that I want to make use of. They typically don't want to swap their drives for new ones without a compelling justification. I get that. That justification is there without question for PMMs for ESP systems on new wells," he said.

Borets also has a new ESP system in field testing. The company did an alpha test a couple of years ago. The new system can manage flow rates over a wide operating range—4,400 bbl/d to 250 bbl/d—and incorporates highly wear-resistant pump stages. "One of the reasons we're able to achieve a wider operating range is because of the high-speed PMM the system utilizes," Simmons explained.

Conventional induction motors operate at 3,600 rpm or 60 Hz. The high-speed PMM operates up to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6,000 rpm. "Having that large a range of speed means you can adjust the speed lower and still operate efficiently at reduced flow rates and with pump stages designed to handle it as well," he said.

For this particular pump system, one of the enabling technologies is the stages, which are manufactured using a metal injection molding process. What that allowed was different stage geometries and improved surface finish that would not otherwise be available through a regular investment casting process. "Using this technique we are able to implement both novel and interesting hydraulic designs but also use more wear-resistant materials," he noted.

Simmons pointed to the typical PMM series—406, 456 and 562. "We have a 406 series PMM. It is a smaller OD motor. We're getting 228 hp in under 25 foot of motor. The 406 is helping because you get greater annular clearance around the motor. You've got better flow for motor cooling. We're finding it helps with things like gas breakout as the produced fluid is moving up to the intake. If you are breaking gas out prior to the intake, you are not going to take it inside the pump as much either."

Switching annular/tubing flow

Annular flow gas lift has been around for many years. It has been used primarily for the initial unloading of a well at very high rates of fluid production. Having a larger flow area initially allows an operator to capture more production. The problem is that annular lift gets to the point where it is no longer efficient, explained Liberty Lift's Archa.

Once a well reaches a normalized production rate, annular lift becomes inefficient. "You start seeing a lot of slugging occurring, and production can be erratic during those slugs. More than anything, it causes downtime—slugging equals downtime and downtime equals less production," he said.

"Over the years a lot of operators have moved away from annular lift just because they know in six months, one year or two years, annular lift is not going to be right for their well. So they abandoned it completely. They didn't want to have to go in and do a $100,000 workover to pull the annular lift system and put a conventional tubing lift system back in the hole," he added.

Liberty Lift Solutions now has a patent-pending solution to that problem. Its HyRate system allows operators to switch back and forth between annular flow gas lift and tubing flow gas lift without having to work the well over, according to Archa.

"This allows the client to benefit from the higher initial rates associated with annular lift with the option to switch to a conventional tubing flow system in the future without working the well over. You can use them at different points in the well's life. Both systems are designed and installed in tandem," he noted.

Liberty Lift does nodal analysis on these installations. If you're producing on annular lift, the company looks at lifting efficiency, bottomhole pressure and nodal analysis to determine the most efficient flow path for each particular stage in the well's life cycle.

"This ensures we won't lose production when we switch from annular gas lift to tubing gas lift. It makes that transition almost seamless," he said.

The HyRate system does not utilize costly side-pocket mandrels. The company uses conventional injection-pressure-operated (IPO) gas-lift valves and checks. The HyRate mandrel allows the company to inject gas down the tubing and into the casing without compromising the ID of whatever tubing the well is completed with and still allows the operator to utilize conventional IPO valves, Archa said.

"Wireline retrievable equipment, such as side-pocket mandrels, are generally expensive. By using commodity gas-lift valves, mandrels and checks, we're able to keep the overall cost of the system a lot lower," he said.

Switching back and forth is straightforward. Annular lift is used during the initial production. Once the operator is ready to inject down the casing and produce up the tubing, it is simple to shut a valve on the surface, then close another valve to achieve those results, Archa said.

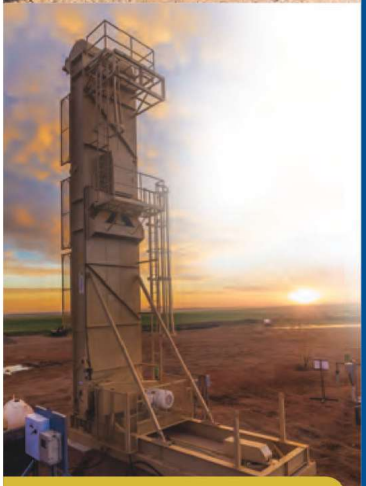
"If a well makes a lot of sand and the operator wants to do an intervention on the well, as far as slickline goes, they don't have to run an isolation sleeve because that is just one less point of failure," he explained. "You've got flexibility because you have preset gas-lift valves on the tubing and annular lift sides. If you needed to tap into an annular lift again, it is a simple flip of a switch. With everything set up on the surface to either continue annular flow or to switch back to tubing lift, we've done the switch in 15 minutes."

Switching back to annular lift generally is needed when flow rates increase. For example, some customers have implemented HyRate after being hit by offset fracks or stimulations. "They may have a well that is making 200 barrels per day," Archa said. "The old style thinking is that if they've got a well with normalized production at 200 to 300 barrels per day, they are going to install a 200 to 300 barrels per day gas-lift design.

"When that particular well gets smoked by an offset frack, all of a sudden it is seeing 3,000 barrels

GAS LIFT SYSTEMS

INSTALLATION AND SERVICE



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Liberty Lift Solutions' patent-pending HyRate system allows operators to switch back and forth between annular flow gas lift and tubing flow gas lift without having to work the well over. *(Photo courtesy of Liberty Lift Solutions)*

per day. The current gas-lift design can't handle it. HyRate allows an operator to go back to annular lift and switch the injection path to take advantage of that much larger flow area to unload the well. Once the well is unloaded and back to a more normalized production rate, then the operator can switch back to its normalized tubing lift," he said.

In some regions, operators generally don't run tubing initially because high-volume gas flow creates more friction. They are just flowing up the casing. What happens is that once the well does load up, they have to install tubing in a workover. They run capillary tubing and gauges at the same time they run their installations. The all-in costs for the average workover run $300,000 to $400,000, Archa added.

By installing this system at the beginning, operators can bridge that gap of lost production, friction loss to the well and not making as much production as they normally would. "Instead of installing tubing, flowing up the tubing and losing production, they are going to install this hybrid system and take advantage of being able to tap into both flow paths," he said.

Rigless ESP replacement

In offshore and remote locations worldwide, intervention costs for replacing ESPs are quite expensive, often leading operators to less optimal artificial lift techniques, primarily gas lift. In Alaska, the typical cost to swap an ESP can be $2 million to $3 million. As mentioned earlier, the cost of replacing an ESP offshore West Africa can be $10 million. Production can be down for over a year after an ESP failure in these operating areas, AccessESP's Malone said.

ConocoPhillips originally sponsored AccessESP technology in 2005 to develop a fully retrievable ESP system that could be pulled through tubing on slickline without killing the well. "The reason they needed that was, No. 1, if there was an ESP failure, they wanted to remediate quickly without pulling the tubing, and, No. 2, in a lot of cases they were drilling horizontals and they needed to get into the laterals to clean sand and do workovers, again without pulling the tubing," he explained.

"We are in the business of rig elimination and reducing production downtime," Malone said. "We work in places where rig access is difficult and expensive, and there is a lot of lost production from ESP downtime."

For example, offshore West Africa, the platforms were never designed for ESPs. "It wasn't considered at the time the platforms were installed. Now they want to make the transition from gas lift to ESPs. What's keeping them from doing that is the fear of ESP reliability and the implications of an ESP failure," he continued.

AccessESP can pull a pump on slickline. "We can go out on a platform with a mast unit and slickline unit. We can do a live-well swap of an ESP. That is a big advantage. When we pull the system, the client has full-bore access through the tubing to the reservoir so they can do coiled-tubing cleanouts. They can do re-entries," he added.

The company focuses on three areas: where gas lift no longer works, where the lost production and intervention costs are high, and preventive maintenance.

"Preventive maintenance is now emerging as a major change in ESP operating philosophy, primarily in Alaska where we've been running the longest. I think the most exciting is the idea of preventive maintenance on ESPs. What we have initiated from last year in Alaska is swapping out the systems on a preventive basis, which is a real change," he said.

"ESPs are complex electromechanical systems operating in a very hostile environment. They have a finite life and are subject to unpredictable failure. This will never change. If I've got a system that has been running for three years, it is like having a car with

50,000 miles. You can run the car until the engine falls out or you can get an oil change.

"With traditional ESPs it is not practical to perform maintenance, so the system runs to failure. What we're doing now is pulling ESPs for maintenance based on time or if there is any indication that there might be a problem. The advantage is in pulling it in a scheduled pull, using simple, low-cost slickline," Malone emphasized.

The associated lost production is two or three days for the workover. At the same time, if an operator needs to modify the pump, do a cleanout or whatever else, it can do that as well. Currently the industry is in a run-to-failure mode. With the ability to go in on slickline and pull a working ESP without killing the well, the cost of maintaining the ESP is pretty small.

"The idea of preventive maintenance of ESPs completely makes sense because then it is a scheduled workover. You don't have production downtime. You're not repairing equipment, you're maintaining the equipment. We pull systems out of the ground. We rebuild and refurbish them at one-third the cost of a new system, and it goes back in the next well, which is a complete change in the mode of operating an ESP," he said.

There are two new technologies that are impacting ESP installations. The first is the development of a very high-density PMM. That is important because the ESP motor must now fit inside the tubing instead of inside the casing. Also it has to be short enough so that it can be deployed with a wireline lubricator. "You want a very high-power motor in a very small package," Malone said.

The second technology is a wet connector that sits in a dock that the ESP plugs into when it is tripped into the well.

"Today if you look at a lot of the deepwater assets, operators would choose to have ESPs in those wells to optimize recovery and field economics. But the cost of an intervention in deep water can be in the hundreds of millions of dollars. The ability to install and retrieve an ESP without pulling the tubing makes that practical whereas a conventional ESP system wouldn't be," he noted.

Tapping into IIoT

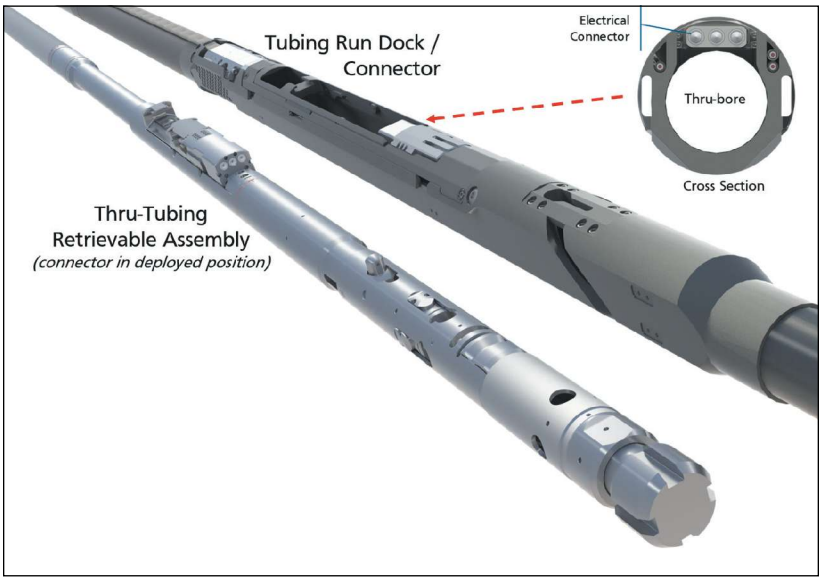
There is value in monitoring and controlling different applications on the wellpad whether these are artificial lift, compression management, vapor recovery units, chemical management or basic production data monitoring, said WellAware's Morgan.

"We are seeing companies have opportunities to improve operational efficiencies and well performance by augmenting existing products or services more efficiently with our IIoT automation solution. This often leads to other potential revenue streams that they can explore with the quality and resolution of data they are now tracking and trending," he explained.

Morgan described WellAware as a full-stack IoT to the cloud company with hardware, software, communication and analytics pieces are managed internally.

The company has two pieces of hardware that are used in the development of custom solutions—the WellAware Integrated Real-time Controller (WIRC) Gateway Plus device and the WIRC EDGE device. Both bring intelligence to the "edge" and result in higher frequency and higher resolution data.

"The Gateway Plus device is really a remote terminal unit [RTU] or a cloud terminal unit with low power utilization. This device has multiple input/outputs [I/Os] that cover pretty much anything you need for most oil and gas applica-



For the AccessESP system, the Tubing Run Dock Connector (or permanent completion) is on the right, while the Thru-Tubing Retrievable Assembly is shown on the left, showing the mating electrical connector in its position when deployed and connected. *(Photo courtesy of AccessESP)*

A field technician uses the WellAware mobile app with the WIRC Gateway Plus to ensure proper chemical injection. *(Photo courtesy of WellAware)*

tions. It also has Bluetooth, GPS, cellular and satellite capabilities," he noted.

"We can tap into an electronic flow measurement or RTU and bring back all of that production data for that location or even bring additional I/O to be visualized on our analytics platform or traditional SCADA. We also offer Native iOS and Android field applications. The mobile app is used to configure the devices in the field and visualize real-time data," Morgan explained.

With WellAware's analytics platform, a service provider or operator can visualize actionable data through custom dashboards, reports and charts that trend multiple data points from multiple sites if needed. These tools then tell them which sites need attention based on their internal metrics and key performance indicators, he continued.

The WIRC Gateway Plus is hardware agnostic in terms of what it can interface with, such as ESPs, POC/RPC, EFM/RTUs, chemical pumps, compressors, vapor recovery units, etc.

"Our remote monitoring and control functionality allows users to change operational set points as needed to optimize performance of their assets without having to be in the field," he said.

The company released a piece of new hardware in 2018 called the WIRC EDGE. This device is a C1D1 certified, explosion-proof device, whereas the WIRC Gateway Plus device is C1D2 certified. The WIRC EDGE is unique in that its architecture allows it to be configured for either pressure, temperature, level or flow applications.

The WIRC EDGE device communicates data via Bluetooth to the WIRC Gateway Plus device. There is no limit to the number of wells or assets that can be managed through WellAware's analytics tool.

The Gateway Plus and EDGE devices easily integrate with existing infrastructure to bring data back to a centralized location so effective action can be taken.

WellAware's chemical management platform is another offering that has been successful. "That is one market that has seen really zero automation in terms of workflow efficiencies and how these assets can be optimized on the wellpad. That market has been traditionally underserved. We're starting to see a lot of traction on the technology side," Morgan said.

"We offer a variety of solutions for chemical service providers and operators, including batch treatment, tank level monitoring, pump monitor and control, and on-demand chemical," he added.

Every application can be custom designed to meet well conditions. As Morgan pointed out, "We don't expect an out-of-the-box solution will work for every customer. That's why we specifically designed our hardware and software architectures to be flexible and scalable to work for a variety of different customers and applications. Our goal is to bring back better data so our customers can experience better results and decision making in their business." ■

Improving ROI on Shale Wells

LPS products have resulted in a significant reduction in tubing leaks and rod failures while increasing overall production on shale wells.

Key to improving ROI on shale wells is maximizing production in the initial stages and having substantially reduced operating costs during the long-term tail production. For the past two years, LPS has developed innovative products and services to focus on both aspects of shale production and we've identified two key areas where LPS products have impacted production and operating costs in shale wells.

Managing Decline

Rod pumping is either used initially or as part of a conversion strategy from Gas Lift or ESP during the later stages of the well. Using LPS continuous rod product, a number of these companies are able to get an extra 10% incremental production due to reduced friction and increased flow.

Reducing Operating Costs

Tubing Leaks and Rod Failures are two of the primary reasons for well failures. Several case studies have shown as much as a 5X reduction in tubing leaks and a significant reduction in well failures.

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Results in graph depict a two year trial when using LPS Lined Tubing.

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Artificial Lift Enters Age of Automation

Systems aid in predicting failures and optimizing production.

By Brian Walzel
Associate Editor, Production Technologies

Once a well goes online it produces not just oil and gas, but vast amounts of useful data that, until recently, many companies weren't quite sure how to utilize. As wells age and are put on artificial lift, they produce more data. Companies with hundreds or thousands of wells in production face considerable challenges to ensure each of those wells is performing to its maximum capability and doing so without a lift system failure.

Taking these factors and challenges into consideration, it would stand to reason artificial lift is ripe for the implementation of automation and monitoring systems. Companies that operate in the artificial lift automation and monitoring space believe such systems help streamline operations and provide valuable and vast information to help operators make better decisions, save money and increase production.

"There's a need to have some workflow around all of this data in terms of how do we high grade what's important, how do we see what we need to act on, and how do we integrate that process of action into a routine process around making controlled decisions," said Graham Makin, vice president of sales, marketing and investor relations for Silverwell.

Automated optimization, he said, enables cross-functional collaboration among different technical disciplines of a company's operations, including

Automation systems from Silverwell allow remote monitoring capabilities. *(Photo courtesy of Silverwell)*

reservoir engineers, production engineers and data analysts, to help realize more value.

"Our world is more production with less intervention and more data for less uncertainty," Makin said. "That's where we are headed."

Automating artificial lift

Today's automation and monitoring systems are leveraging the latest technologies that have similarly helped transform other industries like retail, finance and health care. Companies like Silverwell, Apergy, Ambyint, Baker Hughes, a GE company (BHGE) and Weatherford, among a host of others, apply artificial intelligence, machine learning and Industrial Internet of Things capabilities into their offerings for every type of artificial lift system.

Ambyint's automation system includes a device it refers to as an "edge controller" that integrates operations at the well site and includes a communication device controllable from anywhere in the world via satellite or WiFi.

"About 300,000 wells probably have nothing but a motor and a cheap mechanical timer," said Alex Robart, CEO of Ambyint. "That's the majority of wells out there. We implement a version of our edge controller that serves as the production controller."

The edge controller system takes the manual management of a well's artificial lift operations out of the hands of the lift technician or engineer, Robart said.

Silverwell's Digital Intelligent Artificial Lift (DIAL) production optimization system for gas-lift wells integrates temperature and pressure gradient monitoring with a gas injection rate control capability. Each in-well DIAL unit can have up to six injection orifices, each individually controlled from the surface, with a full spectrum of injection rate options for the well operator. This means it's not reliant on annulus pressure and a pre-determined orifice size to maintain gas injection rates. Makin explained that DIAL in-well units are strategically installed at various points in the well via coiled tubing.

"So what we are driving toward is a multiwell, continually optimized and fully automated gas-lift production optimization system," he said.

Apergy's SMARTEN Total Asset Manager is a well monitoring, control and analysis system that offers remote monitoring, adjustment and optimization. The system's integrated automation and variable speed drives are used to improve efficiencies in rod lift applications, electric submersible pumps (ESP), progressing cavity pumps and hydraulic pump systems by managing the operating speeds and providing event history tracking and logging, which track motor activity and control, according to the company. The downloadable datasets can be wirelessly transmitted to offsite operations personnel for review.

Ambyint's Amplify real-time controller (orange device on gray box) is applied to a wellsite production system. *(Photo courtesy of Ambyint)*

"The evolution of a Production Intelligence based architecture allows for mobility of higher level applications that have historically resided at the software platform and are getting pushed out to the field, so they're closer to the actual end devices and the actual artificial lift equipment," said Ron Holsey, vice president, Production Optimization for Apergy.

BHGE's ProductionLink artificial lift monitoring systems monitor all forms of artificial lift, detect anomalies and help select optimal set point values. The platform provides secure, remote access to authorized users from anywhere in the world, said Anil Wadhwa, BHGE artificial lift digital transformation leader.

"If you were a production optimization engineer based in Houston and there is an electrical submersible pump running in Siberia, you can monitor and analyze well and lift equipment condition, and change the pump operating parameters in real time," he said.

In May 2017, Weatherford unveiled its ForeSite production optimization platform for a variety of lift types. ForeSite leverages advanced analytics, cloud computing and IoT capabilities to predict lift failures and production rates and to choose the optimal lift system for a particular well.

"Not only can you monitor and optimize your wells, but you can also convert decisions into action items," said Manoj Nimbalkar, global vice president, Production Automation and Software at Weatherford. "All of the optimization decisions you have made, you can send those out as instructions to a rig crew to take appropriate actions."

Silverwell's DIAL system integrates temperature and pressure gradient monitoring with the capability to control the rate of gas injection. *(Image courtesy of Silverwell)*

Nimbalkar said ForeSite can be used to optimize production from naturally flowing wells in addition to wells that are equipped with rod lift, ESPs, gas lift and plunger lift. The system performs asset level optimization by integrating well models and surface network models to create optimization workflows.

"This is specifically utilized at companies who have conventional wells that they have to look at how efficiently they can get the oil out of the reservoir," Nimbalkar said. "They look at an interactive optimization workflow and they optimize the well to the surface facilities as well as reservoir well models. ForeSite can integrate all of these workflows together."

Best fits for automation

A variety of automation and monitoring systems have been deployed across every major U.S. oil basin and in many international plays for just about every type of lift system. However, those in the automation sector see different plays and different lift mechanisms as more applicable, and accepting, of automation applications.

Robart said, for example, that operators in the Bakken are more willing to adopt automation technologies than those in the Permian Basin.

"The Bakken has really been built from scratch over the past 10 years," he said. "Whereas the Permian has the same set of folks who have been pumping wells the same way for 50 or 75 years, and they are not too excited about change and someone telling them there's a better way. In the Bakken, folks have been ripping up production over the past five years. The Permian market has been harder because there is just this fundamental resistance to change that's a little harder to overcome."

However, despite the regional reluctance, Robart said Ambyint has made inroads with Permian operators. The company's automation systems have typically found success in the Bakken when companies switch to rod pumps after an initial production run of ESPs. Robart added that a few operators in the Rockies have adopted automated artificial lift systems despite the region being primarily a gas play.

"There's relatively less oil to work with in the Rockies, but that's changing to some extent," Wadhwa said.

The concept of automating and monitoring artificial lift systems is essentially the same for most lift types, whereas the difference in approaches lies in what needs to be monitored and what needs to be optimized.

"With ESPs, customers like to optimize the power consumption," he said. "Power is the biggest cost factor in operating an ESP, followed by the cost of a premature motor failure. Our event-driven prescriptive analytics model utilizes best practices and helps minimize failures to reduce the cost of ESP operations. Failure is not an event, it is a process. It doesn't happen all at once, so we believe in a preventative approach."

Holsey said rod lift systems, ESPs and, to a lesser extent, gas-lift systems, are providing Apergy with a wealth of data that help them better understand a reservoir's production possibilities.

"We have a little better idea of what the reservoir will give us," he said. "For rod pumps, we haven't really figured out how to get a very good measure of bottomhole flowing pressure, so we're still guessing on how much the reservoir allows us to take out. I think that whole world is still evolving."

Makin said Silverwell's monitoring system is able to mitigate instabilities in gas-lifted wells as a result of the control and monitoring the company's system provides. Additionally, an operator's gas budget can be better planned and managed with the ideal gas allocation that an optimized system provides.

Weatherford's automation controllers can be applied to rod lift, gas lift, progressive cavity pumps and jet pumps, Nimbalkar said. The company's next generation of controllers, ForeSite Edge, have the optimization models on the controllers themselves.

"All of these controllers are IoT-enabled, which means they have Signet where you can get the high-frequency data, and using that high-frequency data you can do all the optimization by using the ForeSite models on the controller level," he said. "With the

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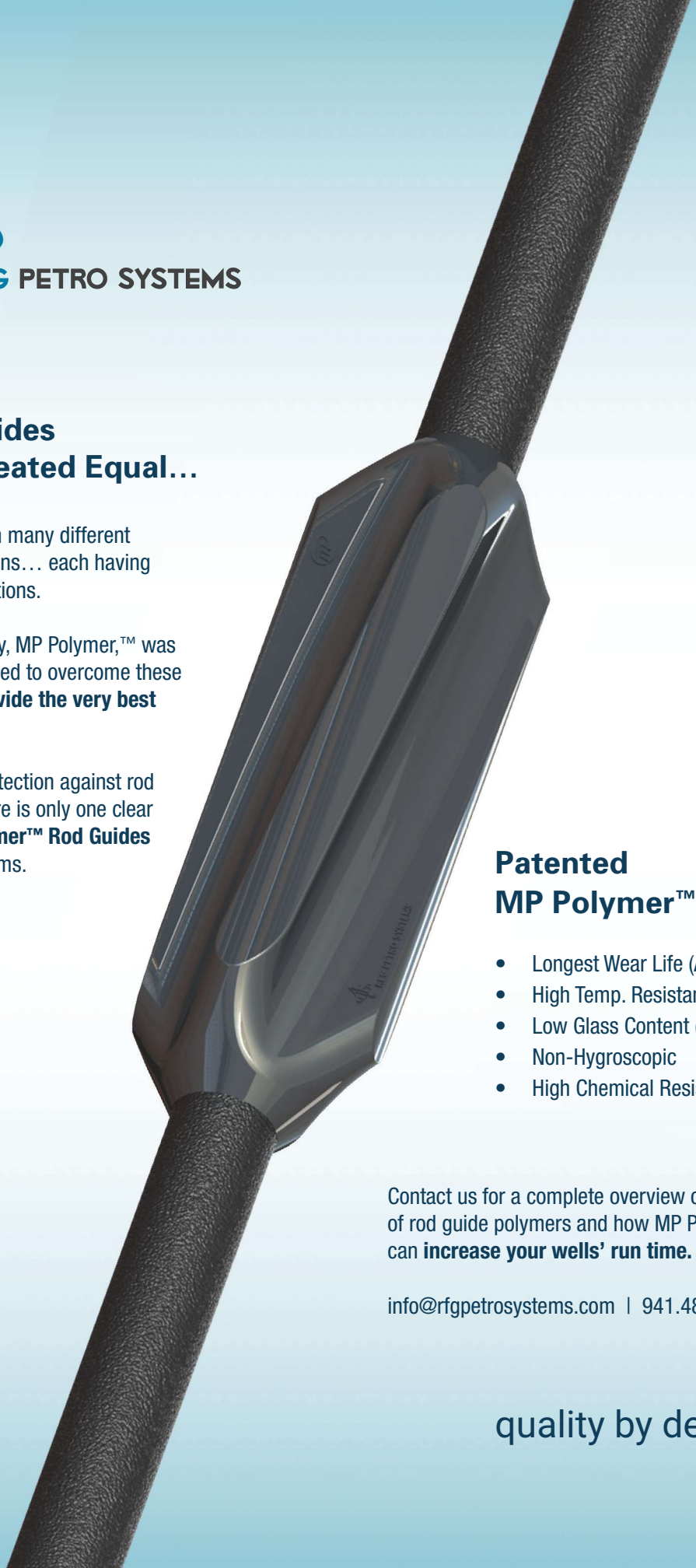

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help of these two systems, we are now able to do autonomous control on rod lift as well as for gas lift."

Case study

Equinor recently deployed Ambyint's IoT-enabled monitor on 50 horizontal wells in the Bakken. The devices replaced programmable logic control (PLC) systems, which Equinor stated were limited in their computational capabilities and were unable to accommodate sophisticated mathematics, which were required to accurately calculate downhole parameters and enable well autonomy. The pilot test included seven months of run time.

A case study on the process and its results was recently compiled by Equinor and Ambyint and presented at the 2018 Society of Petroleum Engineers Artificial Life Conference and Exhibition in The Woodlands, Texas.

The study reported that the monitoring system offered high-performance computational capabilities and direct communication with a cloud-based analytics software platform. The platform was developed to execute higher-order mathematics, artificial intelligence operations and machine learning on high-resolution data, sampled in real time from the rod pump system.

"Legacy technologies have helped to keep fields optimized to some extent," the authors reported. "But in the modern, unconventional age these tools are heavily manual, less accurate and, most importantly, unable to fully automate well operations, which was a goal of Equinor."

Ambyint's IoT device was connected to the operator's legacy rod pump controller via Modbus connection over two phases. Phase 1 included 20 wells and Phase 2 added 30 wells.

"Immediate differences in key downhole parameters were observed when comparing the results from the traditional rod pump controller to the IoT device," the study reported.

The data from the rod pump units was fed into Ambyint's machine learning algorithms and identified under-pumping, over-pumping and dialed-in wells.

"Using improved downhole information, Equinor was able to automate well optimization setpoint decisions, resulting in reduced well volatility, better pump efficiency and increased pump fillage," the authors stated.

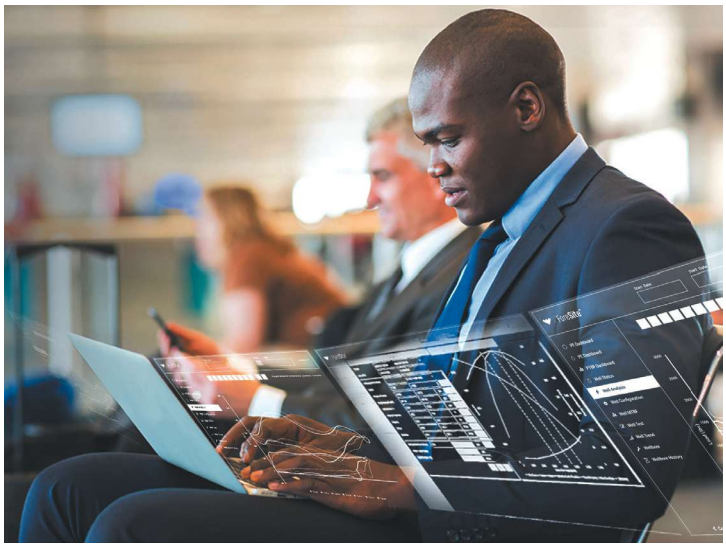
Equinor and Ambyint identified wells that were either over-pumping or under-pumping in order to optimize stroke-per-minute (SPM) setpoints, which resulted in the operator achieving higher efficiency results with the same or increased production. Equinor found that by implementing the IoT controllers, it was able to increase production on the under-pumping wells by 605 bbl, or 33%. For the under-pumping wells, Equinor decreased the number of strokes by 11% and increased pump efficiency by 14%, according to the study. In addition, the authors noted that the SPM reduction on the under-pumping wells resulted in equivalent electricity cost savings from 59 potential fleetwide workovers annually.

"This pilot shows that the vision of autonomous well operations is possible to implement," the authors stated, "and the operator investment in modern optimization technology over and above that which has already been deployed to enable autonomy provides lasting, repeatable value through a multitude of operational parameters."

Value proposition

The ultimate goal of any new technology in the upstream oil and gas industry is twofold: to increase production and to lower costs while doing it. The same is true for automation systems for artificial lift operations, whose proponents say can help companies better meet decline curve expectations and improve recovery rates.

"Of the couple of thousand wells that we're on, only about 10% to 15% of those wells are actually optimized," Robart said. "Which means a lot of these



Weatherford's ForeSite software integrates physics-based models with advanced data analytics to maximize production. *(Photo courtesy of Weatherford)*

wells are producing under their potential, just by the fundamentals of how they designed that well. We are allowing them to actually get back up to their theoretical production potential."

Holsey said his company's automation systems have helped realize a 25% reduction in maintenance costs through efficient equipment operations and, ultimately, somewhere between 5% to 10% production improvement.

"So just by operating the equipment better, we're getting more production based on our algorithms," he said.

Makin said Silverwell has worked with multiple operators to predict the value of optimizing single and multiwell gas-lifted systems and routinely realizes a 10% to 20% production increase.

"Additional to that, there is a goal of achieving optimization without any intervention," he said. "So there is no intervention to change out gas-lift valves, to change injection rates and to collect pressure and temperature data."

Robart explained that the value derived from artificial lift automation and monitoring systems is typically dependent on the age of the well and how it's being run. He cited a case of a set of horizontal wells in the Bakken for which Ambyint's systems have helped increase production by about 5%. By fine-tuning the number of SPM, the optimization process helped reduce electricity costs, minimizing energy usage and reduce potential damage to over-pumping wells.

"We're not fundamentally changing the nature of the reservoir," he said. "That reservoir is going to produce fluids that the reservoir—combined with the stimulation—is going to produce. What we are doing is enabling [operators] to actually produce up to the potential of that well based on the reservoir and the stimulation implemented at that reservoir."

BHGE employs a manage-by-exception methodology in its remote monitoring and automation systems, one that Wadhwa said doesn't necessarily analyze every datapoint at all times, but instead recognizes special patterns and sends notifications if an anomaly is detected. The benefits of this approach include high reliability and scalability.

"We want to help operators reduce their operating costs," Wadhwa said. "We want to reduce the number of trips field technicians need to make to see what is going on at the wellsite. They should focus on just a few wells, not hundreds."

With a goal of sustaining maximum hydrocarbon production while minimizing costs, optimizing artificial lift operations helps ensure setpoints match reservoir inflow and maintain a full pump, as Equinor and Ambyint explained in their recent case study. A properly dialed-in well helps ensure maximum production over a longer run time as well as limited exposure to potential failures.

"People wouldn't be adopting this system unless we were saving them lots of money or giving them an uplift in production," Robart said.

Leveraging field experience

In an industry that places a high value on personal relationships and in-the-field know-how gained from decades of experience, companies have often been reluctant to adopt digital and automation technologies. The argument is that Big Data can't replace gut instinct. However, companies that apply automation to artificial lift say their technologies only serve to enhance that know-how and also allow field workers and production engineers to focus their time and attention on more important tasks.

Holsey explained how field operations technicians have become responsible for increasingly more wells over the course of the past several years, and now might be in charge of ensuring that hundreds of wells are running properly and up to their full production potential.

"[The field operations technician] just can't go to all the wells," he said. "So he spends his day chasing what went down, how to get that well back in production. That's where technology steps in and helps him. That algorithm is running 24/7 in the background. But I don't think it's any smarter than that 35- or 40-year-old oilfield veteran out there. It just makes his work more efficient."

Paul Mahoney, president, Production and Automation Technologies at Apergy, said his company has been investing in artificial intelligence and predictive capabilities to better predict well performance early detection of failure modes. But he said in many of Apergy's early cases, many of the predictive results would be mirrored by more senior experienced engineers.

"Our experience highlights the need to marry technology/reliable data with strong formulaic calculations and downhole experience for actionable insights as the predictive models iterate, having subject matter expertise installed base experience is essential," he said.

Silverwell's Makin said the adoption of automation systems helps enable a more collaborate, cross-functional approach to operations so that everyone has an understanding of the value associated with the technology.

"We make the hidden value visible," Makin said. "We make it easier to act on it, but we still need the same basic engineering and analytical skillset in the minds of the people doing it. We just make it easier to do." ■

The Advantages of Analytics

Better leveraging data can result in improved production.

By Sandy Williams, Artificial Lift Performance

Analytics has a very obvious attraction for the oil and gas industry—how can more wells be managed effectively with fewer experienced engineers?

If analytics can help improve performance in sports such as stock car racing and football, or even diagnose when an elevator needs maintenance, all based on real-time data, how can analytics be used to improve the ability to produce oil wells using artificial lift?

An article published by Bain & Co., a global management consultancy, states that "analytic advantages could help oil and gas companies improve production by 6% to 8%," which is what operators typically gain when they implement Artificial Lift Performance's artificial lift optimization software.

When using artificial lift, oil companies pay to achieve a certain drawdown and achieve additional production. If the artificial lift method underperforms, production is lost. Using analytics, it is possible to analyze and diagnose the artificial lift performance for every production test automatically and identify when the lift system has a problem, resulting in lower production.

Operators can spend about $10 million fracking and completing an unconventional well. The goal is to then produce the well at an appropriate rate to ensure rapid payout. When a well is planned to produce 2,000 bbl/d and then only produces 1,500 bbl/d, production is lost. Artificial lift analytics can tell whether this is a result of a well inflow problem or an issue with the artificial lift. The ability to identify poorly performing artificial lift systems is critical to optimizing production.

Gas-lift analytics

Ideally, a downhole pressure and temperature sensor should be installed on all gas-lift wells. Every production test could then be analyzed to verify the injection point and address the challenges: determining how much more production could be achieved by more and deeper injection.

On existing wells that do not have a downhole sensor, a good practice is to perform a gradient survey monthly to verify the injection depth and ensure that the well is producing optimally.

Because of the uncertainty around inflow performance relationship (IPR) on unconventional wells, traditional nodal analysis cannot predict well performance. Instead, it is important to have a top-down process to verify injection depth and predict well performance.

Unconventional wells can often have 10 to 15 mandrels in the wellbore to account for inflow uncertainty and to be able to produce the depleted well later in life. Having so many mandrels in the wellbore means the design information has to be extremely accurate, which inevitably results in valves staying open when they should be closed and injection at multiple valves (also known as multi-pointing).

Figure 1 shows a gas-lift well with a production test and data from a gradient survey. The software determines that the deepest possible injection point is at mandrel 4 and that all the mandrels above that point are open. The software also predicts if additional production can be obtained by injecting more gas in the upper four valves versus injection at the orifice and compares the results.

Performing these calculations automatically every time there is a production test on the well allows for constant screening and flagging of wells where

- Injection is very shallow;
- Flowline differential pressure is excessive;
- Back pressure is high;
- The injection rate is low and may result in slugging;
- The injection rate is high; or
- The injection flowline is plugged/closed (hydrates).

Having this knowledge constantly across all wells is the holy grail of production optimization and is the true value of analytics with respect to production optimization.

ESP analytics

In a report by Stephen Rassenfoss in the *Journal of Petroleum Technology*, it was indicated that gas-lift production losses can go undiagnosed. However, there is a similar phenomenon with electric submersible pumps (ESP). If an ESP is worn, has a blocked intake, is running in reverse or has deposition, it can be running but not producing as it should. Most operators never identify these scenarios, which results in lost production.

An ESP, like any other artificial lift method, should reduce bottomhole flowing pressure. Any time the ESP has a problem such as deposition in the pump or pump wear, the ESP creates less drawdown and well production is reduced. Using analytic tools, it is possible to analyze the pump performance every production test and quantify pump degradation, identify poorly performing pumps and provide recommendations related to recuperating a lost amount of production.

Figure 2 shows a well that has declined rapidly in production over three months. The operator believed the decline was associated with the well's IPR. However, implementation of the ESP analytic tool proved categorically that the production

Figure 1. The chart depicts an automated analysis of a production test with gradient survey on a gas-lift well. *(Image courtesy of Artificial Lift Performance)*

decline was a result of a pump problem. A proactive workover was performed, which confirmed the pump issue was a result of scale inside the pump. The new pump resulted in an additional production of 610 bbl/d.

Properly applying analytics

When it comes to using analytics for optimizing production of wells, the tools exist, the computing power exists and real-time data from SCADA systems have existed for decades. However, the challenge the industry faces is that it doesn't always have the correct data that are required to optimize wells, or that it is not using automation appropriately. There are several areas in which operators can still improve.

For example, field staff still record downtime on a well-by-well basis manually and enter it in the production reporting system manually each day. Automation can perform this task much better and achieve much better granularity, so that all downtime is captured.

Additionally, wells on artificial lift often have real-time downhole information but no wellhead and casing pressure transducers to bring in flowing pressure and temperature or casing pressure. Any well analysis software requires flowing pressure and temperature to perform analysis.

When production tests on wells are recorded, the artificial lift operating parameters are seldom recorded with the tests. Only oil, water and gas rates are recorded along with wellhead pressure. For an ESP, the operating frequency, pump intake pressure and pump intake temperature should be recorded simultaneously so that ESP performance can be analyzed.

Downhole completion information is entered by drilling and completion staff who might not understand what information a production engineer or analytic software tool needs to analyze, for example, gas-lift valve depths and settings or ESP pump type and stages. The format for input of the artificial lift system details needs to be standardized so it meets the needs of the software tools and automatic population of those tools can be performed.

The technology exists to identify gas-lift and ESP produced wells that are losing production as a result of an undiagnosed artificial lift problem. The ability to diagnose and rectify such issues can alleviate lost production.

The biggest challenge that the industry faces for appropriately applying analytics is a failure to collect all of the data needed in a synchronous manner. It's an easy fix, if and when automation, production and IT combine to ensure that a complete dataset exists for true production optimization using analytic tools. ■

References available upon request.

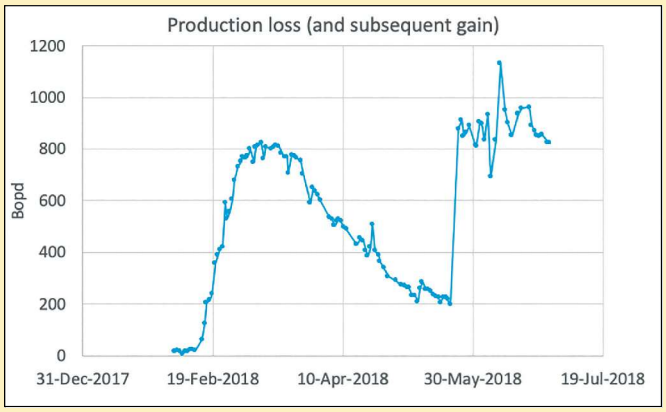


Figure 2. The chart depicts production loss over time due to a pump issue and subsequent production gain after a proactive replacement. *(Image courtesy of Artificial Lift Performance)*

A Simple Solution to Runlife Extension

Coupling alloy extends runlife of rod-pumped wells.

By William Nielsen and **Richard Cash**
Materion Corp.

Nearly 50% of failures in deviated shale wells operating on artificial lift are attributed to metal-on-metal contact of sucker rod couplings and production tubing. Workovers and production losses can cost companies tens of thousands of dollars per well per year. Working with a large operator that was experiencing high failure rates in some of its Bakken wells, Materion Corp., which specializes in the supply of advanced materials, developed sucker rod couplings made of a new temper of its ToughMet 3 alloy, an advanced bearing material long-established in oil and gas drilling applications. It is notable for its high strength and anti-galling qualities.

After successful field tests in 10 problematic Bakken wells, between 12 and 60 ToughMet couplings were installed in 50 deviated well sections by operators throughout the Bakken, Permian and Eagle Ford basins. In this pilot program, known as "Solution 1," a 62% average increase in tubing runtime was observed after ToughMet couplings were installed in the bottom of rod strings. Throughout the trial, it was noted that there were two instances in which the wellbore was so severely deviated that nothing could be done to improve the wells' performance.

Materion's ToughMet alloy couplings have been deployed in the Bakken, Eagle Ford and Permian basins. *(Source: Materion Corp.)*

Expanding the program

During the Solution 1 pilot runs it was noticed that placing an increased number of couplings in the well, spanning a larger area than just the deviated sections, could give rise to significant benefits. Namely, the overall frictional loss of the machine could be significantly reduced, along with the mechanical loads on all the surface equipment and the energy consumption of the system—ultimately increasing the output of the well. Solution 2 was subsequently launched as a program to investigate cases in the Permian and Bakken where much longer portions of the sucker rod string were outfitted with the couplings.

A broad sample size was acquired in order to mitigate for any operating practice variations among operators. The goal was to perform a statistical analysis on the results as a whole population, not on a case-by-case basis, to understand if, in fact, the "before" and "after" were statistically different operations and what type of distribution the results conformed to. By drawing results from such a large data-

Component	% of Wells	
	Improved	Did Not Improve
Oil Production	73%	27%
System Efficiency	78%	22%
Downhole Stroke	86%	14%
Pump Fillage	73%	27%
PPRL	91%	9%
Load Range- Pol Rod	91%	9%
Gearbox Loading	94%	6%
Fluid Level AP	83%	17%

Figure 1. This chart depicts the Solution 2 trial results to date for average changes in efficiencies for the different measured components. *(Source: Materion Corp.)*

set, potential clients can be better reassured that the deployment of multiple couplings in this fashion will result in performance improvements unachievable with a more conventional approach.

Analyzing Solution 2

In addition to all the benefits afforded by Solution 1 (wear reduction, mitigation of holes in tubing, etc.), Solution 2 offers more than 100 ToughMet couplings in a large section of the rod string to reduce sliding friction on the rod string and loading. When these large numbers of couplings are deployed, the operator starts to observe positive changes in their wells.

Solution 2 trials: performance analysis. Twenty-two full strings and five large partials were being monitored across 14 major operators in the Permian, Bakken and West Coast. Materion collaborated with the operators to analyze various metrics on these wells. The ToughMet couplings were observed and monitored to assess how they affected the performance of the wells.

Observations. A number of the wells were pulled out of the data set due to the concern that special causes such as nearby fracking, for example, may distort fluid production data. Data from 16 of the wells that were considered to be reliable data sources by the production engineers was retrieved.

It was observed that overall system friction was reduced, resulting in a range of benefits in production performance (Figures 1 and 2). The effects that the couplings demonstrated in the wellbore include an improvement in sucker rod string movement, decrease in mechanical loads on the polished rod and gear box, better pump fillage, increased overall system efficiency and increased fluid production. About 73% of the wells in the sample set have seen improved oil production with the average change of at least 12.6% increase in oil production. Of those tested, 78% have shown system efficiency increases and 86% of the wells demonstrated downhole stroke increase.

The most notable result observed was in load reductions; 94% of wells experienced reduced gearbox loading with an average reduction of 12.5%. Regarding changes to load on the polished rod, 91% of wells experienced a smaller range between peak and minimum load with an average reduction of 12.1%. By shortening the load range (or alternating stress) in these instances, fatigue is reduced.

Statistical significance. In almost every case, the before-and-after data pairs followed a normal distribution. Paired sample t-test analyses confirmed statistically different results for all of the important measured performance parameters following the installation of a full, or nearly full, string of ToughMet couplings. The statistical analysis provides the operator with confidence about the likelihood of realizing benefits and the degree thereof.

Component	Average Change	
Oil Production	12.6%	↑
System Efficiency	20.6%	↑
Downhole Stroke	16.0%	↑
Pump Fillage	6.4%	↑
PPRL	-13.1%	↓
Load Range- Pol Rod	-12.1%	↓
Gearbox Loading	-12.5%	↓
Fluid Level AP	-23.8%	↓

Figure 2. This chart depicts Solution 2 trial results to date by measured improvement percentage for the different measured components. *(Source: Materion Corp.)*

Conclusion

The Solution 2 trials have proved to deliver friction reductions down to one-third of what the system was losing in the way of lifting power due to frictional losses. The stroke length of the piston inside the pump has significantly increased, the overall system efficiency, which is an overall measure of the hydraulic work that is done by the system relative to the amount of energy input, has significantly increased and there have been increases in production, in some cases to up to 30%. In addition, the mechanical loads on the surface equipment—the gearbox, the polish rod, etc.—have been brought down substantially.

The results reported to date continue to be compelling; Solution 2 enhances both the runlife and the performance of rod-pumped wells. ■

Adding Value with Downhole Compression

Downhole artificial lift technologies improve gas production and recovery in liquid-rich gas wells.

By Kuo-Chiang Chen
Upwing Energy

As gas wells mature, production tends to fall off, caused by declining natural drive energy from reservoirs. When the natural drive is too low to generate enough gas production at the surface, the well will normally be abandoned due to economic factors. Sometimes even before a gas well reaches its predetermined economic limit, the lower gas production reduces the gas velocity, which in turn decreases the liquid-carrying capability of the gas stream. The low liquid-carrying capacity makes liquids drop out of the gas stream and accumulate in the well to form a hydraulic column. This is called liquid loading. The hydrostatic pressure of the liquids causes the reservoir pressure to slow down or even stop gas production completely, eventually resulting in premature abandonment of the gas well. Industry estimates reveal that only about 60% of natural gas from reservoirs is recovered from conventional wells and only about 15% to 20% is recovered from unconventional wells.

Existing artificial lift methods for gas wells remove liquids in the vertical sections of the well or reduce the hydrostatic pressure of the liquid column. Current artificial lift technologies, however, cannot remove the liquids completely in both the vertical and horizontal sections of the well or increase reservoir drawdown.

Reliable downhole artificial lift

To address these challenges, Upwing Energy has developed a practical, robust and cost-effective downhole artificial lift system. The company's new Subsurface Compressor System (SCS) changes the pressure profile along the depth of a gas well (Figure 1). It provides both a suction effect to lower the intake pressure near the producing zones and a boosting effect to increase the discharge pressure downstream of the compressor. The lower downhole flowing pressure increases drawdown, facilitating the flow of gas from the formation into the wellbore to increase production (Figure 2). The higher discharge pressure from the compressor will overcome the pressure losses along the pipe and increase the wellhead pressure to flow the gas into the surface gathering system.

With both the suction effects and the boosting effects of the subsurface compressor at work, the well can produce gas from the formation under the lowest possible downhole pressures or even close to vacuum, while forcing the produced fluids uphole with enough push. This in effect increases production and delays well abandonment (Figure 3). With the delayed abandonment, the accumulated gas production from the well, and thus the recovery factor, will be highly improved.

The subsurface compressor also reduces liquid loading (Figure 4). With the increased gas production due to higher drawdown as well as the suction effects of the subsurface compressor, the gas velocities in the wellbore at the intake side of the subsurface compressor will increase tremendously. The higher gas velocities in turn will improve the liquid sweeping capabilities of the well in both the vertical and horizontal wellbore. At the intake side of the subsurface compressor, the lower pressure will promote the mass diffusion of the liquid molecules into the high-velocity gas stream. This further increases the liquid sweeping capabilities. Thus, both the higher gas velocities and lower pressures in the well will enhance the liquid

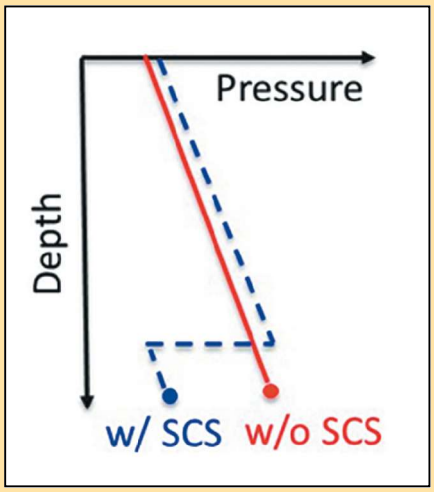


FIGURE 1

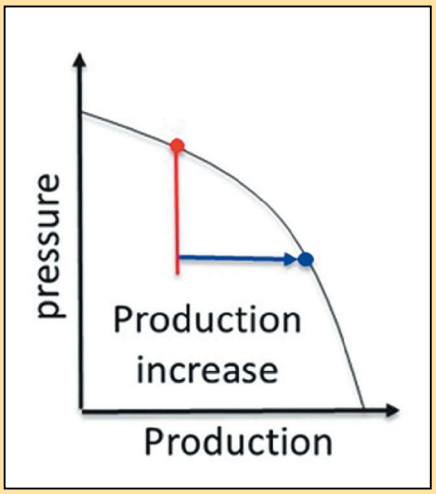


FIGURE 2

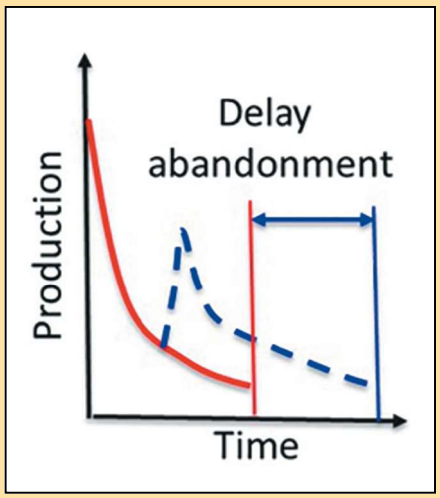


FIGURE 3

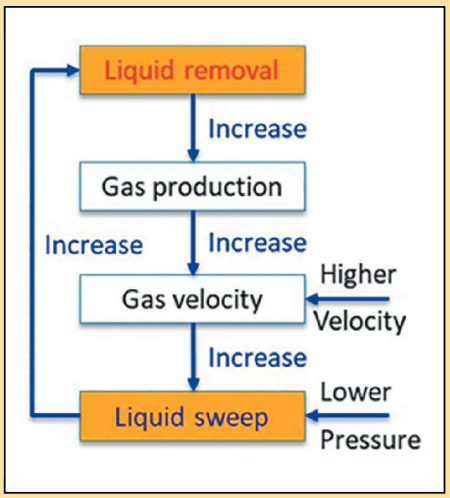


FIGURE 4

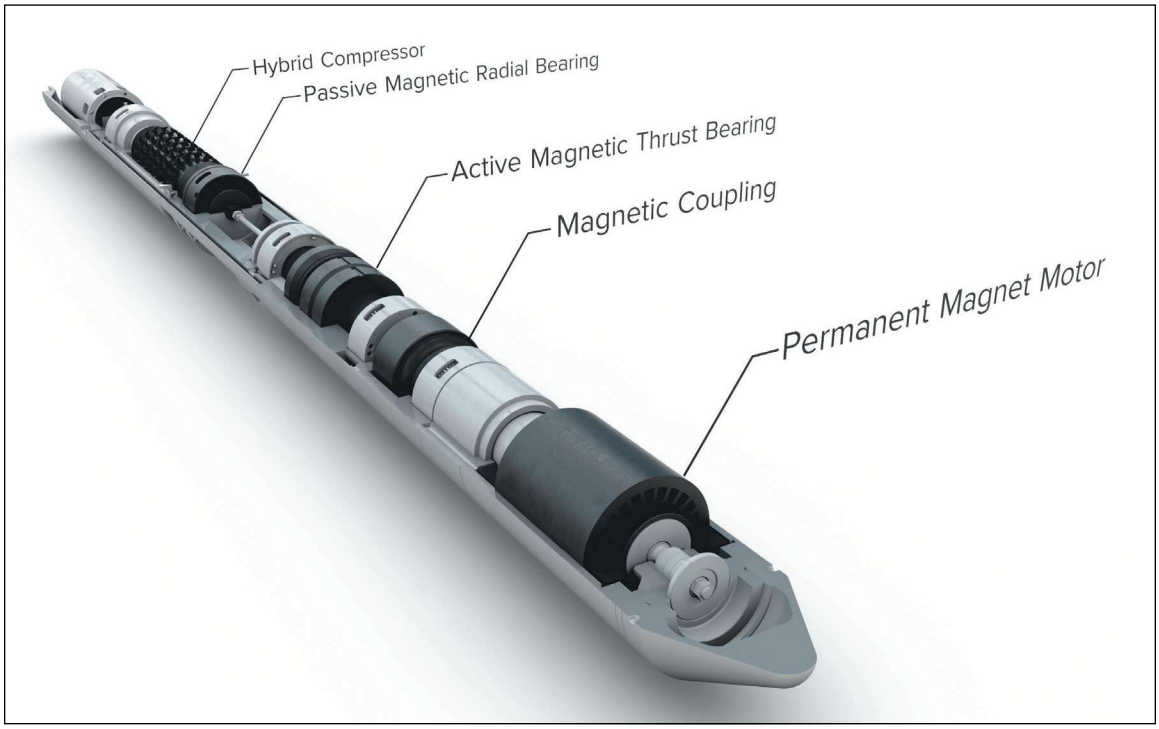
The Upwing SCS combines magnetic technology building blocks into a "protector-less" architecture for the harsh downhole environment. *(Image courtesy of Upwing Energy)*

removal from the well. With the liquids removed from the well, and the absence of the backpressure counteracting on gas reservoirs, gas production will further increase. The closed loop of the virtuous cycle of enhanced liquid removal (Figure 4) can only be enabled by the higher gas velocities and lower pressure generated by the subsurface compressor.

'Protector-less' architecture

The downhole portion of the subsurface compressor is composed of three modules, namely the hydraulic unit, bearing unit and motor unit.

The motor unit contains a permanent magnet motor as the prime mover of the subsurface compressor. To compress gas, the rotation speed of the subsurface compressor is set at 50,000 rpm, which is much higher than 3,600 rpm of a typical electric submersible pump to move liquids. The motor is filled with low-pressure inert gas and hermetically sealed from the downhole environment by an isolation can. More importantly, no downhole fluid or debris can get into the hermetically sealed motor unit, avoiding the electrical or contact bearing failures associated with such exposure.



Major system components of the Upwing SCS are depicted. *(Image courtesy of Upwing Energy)*

A pair of magnetic couplings is used to transmit torque from the motor unit through the isolation can to the magnetic bearing rotor. Using a magnetic coupling to transmit torque eliminates the need for a solid shaft, and thus no need for shaft seals to isolate the motor from the environment.

All seals are known to fail eventually. Seal failures will lead to the ingress of downhole fluids into the parts that cannot be exposed to the downhole fluids. This eventually causes multiple possible failure modes of the downhole rotating devices. To fundamentally eliminate all these failure modes, the best approach is to eliminate the protector containing the shaft seal, which is why the architecture is described as "protector-less."

The magnetic bearing unit is connected to the top of the motor unit. The bearing unit contains active magnetic thrust bearings and passive magnetic radial bearings to support the loads from the hydraulic unit. The most important advantage of using magnetic bearings compared to the traditional mechanical bearings is their reliability and efficiency for high-speed rotating devices. Since there is no physical contact between the rotors and stators of magnetic bearings, there will be no failure caused by introductions of foreign debris on the contact surfaces and efficiency loss due to frictions.

The hydraulic unit houses the gas compressor, which is designed to increase the pressure ratio of the discharge pressure to the intake pressure of the subsurface compressor. The compressor rotor is fully levitated by the magnetic bearings and spins at high speed without any physical contacts to the stationary part of the compressor.

Summary and status

Upwing's SCS increases gas production by decreasing bottomhole flowing pressure and causing higher reservoir drawdown. Effective drawdown can only be achieved by downhole compression near the perforations, where the gas is denser due to the higher downhole pressure. The effective drawdown increases the production rate significantly, which increases cash flow and net present value.

The SCS proof-of-concept field trials demonstrated an increase in gas production ranging from 30% to 58%. Gas well simulations with SCS installations have shown gas production increases ranging from 20% to 150%. In addition to better gas production, analysis shows that the SCS increases condensate production rates and improves condensate yield, particularly in horizontal liquid-rich formations, which positively impacts well performance and value. ■

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