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Artificial Lift Techbook

2017

A supplement to

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Hart Energy's Techbook Series

The 2017 Artificial Lift Techbook is the 12th 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.

To learn more about E&P technology trends, ***visit EPmag.com.***

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On the cover: Oil and cotton share the "Top Crop" crown in the Permian Basin. *(Photo by Jennifer Presley, Hart Energy)*

The sun rises on a blustery day, bringing more light than warmth to the crew working over a Permian Basin well located outside of Midland, Texas. *(Photo by Jennifer Presley, Hart Energy)*

Pumping for the Future

Enhancements to artificial lift systems continue to evolve as operators lean on proven technologies more to maximize output of maturing assets.

By Jennifer Presley
Senior Editor, Drilling

It is true that what goes up must come down, but where does one start when what is down is unable to go up? There are a variety of artificial lift systems that operators can use when this happens to be a condition facing an oil-producing well. The dynamic life of a producing well requires equally dynamic lift solutions to ensure long-term recovery rates.

In this new era of lower-for-longer, operators are challenged to find ways to maximize the value of their maturing assets—both conventional and unconventional. While a mature conventional well will experience a decline in production rates over a span of years, unconventional wells often experience a sharp decline in production in a span of months. Artificially lifting wells either improve or maintain oil production using a variety of lift systems over the life of the well. Just as no two wells are alike, there are no "one-system-fits-all" solutions.

According to a recent Mordor Intelligence report, artificial lift techniques have been applied in more than 95% of the world's oil producing wells. The global artificial lift market is estimated by Mordor Intelligence to be more than $13 billion for 2017. Driving this market is the increasing use of artificial lift systems in North American unconventional wells and maturing fields.

In this edition of Hart Energy's *Artificial Lift Techbook*, different aspects of the market, including its evolution through technology advances and case studies, are reviewed.

The discussion opens with Mordor Intelligence providing a look at the current state of the global artificial lift market with updates on the status of the technology's use. The Key Players section features detailed descriptions of the leaders bringing artificial lift technology advances to the market.

Digital advances, efficiency gains and selection flexibility are just three areas where artificial lift has evolved, and they are driving its future, thanks in part to data analytics and improved material sciences. There's more to artificial lift than the "nodding donkey" beam pumps. Electric submersible pumps (ESP) began making inroads with operators as operational demands have expanded. Gas-assisted plunger lift systems provide an alternative to beam pumps and ESPs, combining plunger lift with gas lift to create a lower cost, lower maintenance option for operators.

Included in this edition of the techbook is a showcase of 14 new or updated artificial lift technologies that have advanced rigless deployment, tubing anchoring, solids handling, multiphase pumping and more.

In the Case Studies section, three providers share their solutions to common artificial lift challenges. This chapter includes case studies that address a variety of challenges encountered in unconventional wells, including:

- Extending the life of sucker rod couplings in deviated wells by using a highly durable alloy of copper, nickel and tin;
- Optimizing production from ESP systems using real-time monitoring and data analytics platform; and
- Reducing costs and increasing production through the use of permanent magnet motors in ESP systems.

Artificial lift will long have a place in the industry's toolbox, ready to help operators and production engineers tackle the increasingly difficult nature of maximizing production in challenging wells. ■

Investing for Enhanced Returns

Artificial lift is key in wells worldwide amid a lower-for-longer scenario.

By Swarna Chaitanya
Mordor Intelligence

Oil- and gas-producing wells have rarely achieved their absolute potential without external force. Artificial lift systems are installed in these wells to increase the flow from the wellbore when there is a need to supplement the natural reservoir drive. Various techniques have been developed and applied on more than 95% of the wells worldwide to increase their productivity over the short term as well as in the long term. Artificial lift technology historically has been a strategic investment made by companies in the oil and gas sector to increase the production from a well.

But a key development that has led to a disruption in the oil and gas industry in the last few years is the onset of oil and natural gas production from unconventional sources. Producing hydrocarbons from unconventional reservoirs is tricky due to production declines of more than 70% within the first year. Artificial lift is one of the most useful techniques that can help increase the production from unconventional as well as conventional wells. Considering these factors, the global artificial lift market is estimated to be $13.25 billion in 2017.

Efficiency and optimization

Following the oil price downturn in recent years, the two most important objectives of almost all companies involved in the sector are increasing efficiency and optimizing costs. The turmoil has forced these companies to constantly innovate—to come up with future technologies that are digitalized and standardized with increased transparency.

The use of artificial lift technology is inevitable in existing fields as well as in emerging plays. The increase in E&P activities across unconventional resources in North America and newfield development projects worldwide, along with an increase in drilling activity and the need to offset rapid production decline from unconventional fields, are some of the factors driving the demand for artificial lift systems. The presence of a high number of mature and maturing oil and gas fields as well as the probability of oil and gas deposits in the vicinity of existing fields is expected to accelerate the market for artificial lift in the short term. Despite the postponement or cancellation of capex, which led to the reduced demand for all oilfield services, the demand for artificial lift systems declined less than most of the other oil and gas price-dependent sectors. This is primarily due to the use of artificial lift systems for production optimization.

Increasing competitiveness among oil and natural gas producers whose reserves are nearing the end of production has put pressure on companies to revitalize these maturing assets and maximize the output. Of the various technologies available in the artificial lift segment, companies are ready to try different artificial lift technologies to boost the production of a particular well.

Moreover, the relentless pace of the growth of energy demand is expected to grow the market for artificial lift systems. The oilfield service companies that provide artificial lift have, during the last two years, innovated and helped to enable the oil and gas market revival. About 70% of the oil produced is from maturing fields, 90% of oil and gas fields use some form of artificial lift, and 94% use them at least once in the field life, augmenting market growth. Most of

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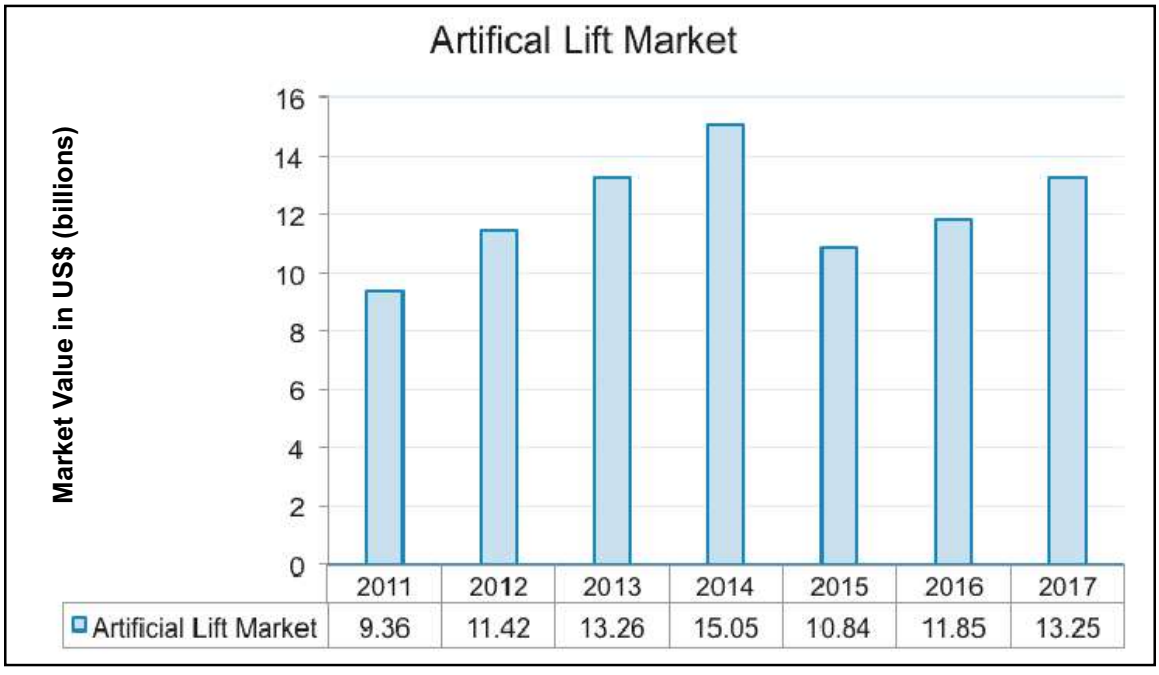

(Data courtesy of Mordor Intelligence)

the recent exploration capex has been on unconventional sources or deep and ultradeep offshore reserves. Thus, the demand for artificial lift is expected to increase in the next five years owing to the success of the aforementioned investments.

Among the regions that contribute significantly to global oil and gas production, North America is expected to account for more than half the market for artificial lift. Most of the wells drilled in the region have reached a stage of maturity, and the new horizontal wells need artificial lift in some form for optimizing production, which is considered as the primary reason for the maximum market share and the basis for market growth in the next five years.

Global market

The low oil price environment has affected most of the big players in Europe. A majority of future supply is expected to come from existing maturing and matured wells. The change in demand from 2016 is meager in Europe; Asia-Pacific, on the other hand, is expected to have a decent growth in demand for artificial lift. The primary driver accelerating the demand is the investment made by the Chinese and Indian governments for securing their future energy needs. Large-scale investments from Southeast Asian nations such as Malaysia and Singapore further drive the demand in the Asia-Pacific region.

Of the various technologies available in the artificial lift market, electric submersible pumps and rod lift contribute to more than 75% of the market share. The ease of installation and maintenance combined with the increased effectiveness of producing wells propel the market for these techniques. But as newer reserves are found in deeper, tighter and more difficult formations, there is a growing demand for customized artificial lift systems engineered for specific well conditions to realize the full potential of the asset. In the next five years innovations are expected in other artificial lift technologies, and their market is expected to grow at a decent rate.

The leading oil and gas players of the world, whose production has a significant effect on the oil and gas industry, have agreed to cut their output. This initiative by countries like Saudi Arabia and other members of OPEC, though struggling to maintain production cuts, has created a positive attitude in the oil and gas market, and the resulting optimism has fostered additional interest to invest in the sector. Owing to this optimism, the oil prices have rebounded and have spurred the number of active oil rigs in the U.S.

As of press time, additional oil price stabilization was expected assuming an extension in coordinated production cuts. However, an increase in production from non-OPEC members eager to capture market share is likely to drag the prices down. But a turnaround for the sector is expected within 2017, and the artificial lift market is expected to see a new high in the next few years. ■

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The Halliburton REDLift™ XT ESP Production System combines wide-range electrical submersible pumps, robust motors, superior gas mitigation products, and a collaborative operating/monitoring strategy to help optimize and get the most from your wells. For unconventionals, this system can increase drawdown, endure sand abrasives, and effectively perform through rapid decline rates. In mature fields, the system can reduce power consumption, increase equipment uptime, and offer a longer system run life.

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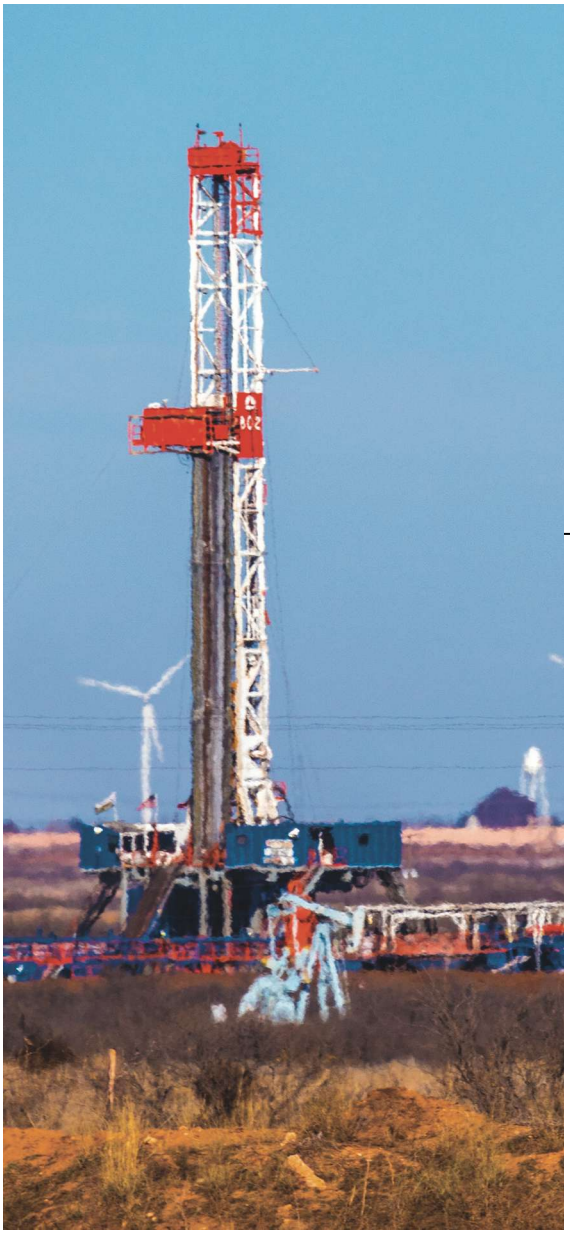
HALLIBURTON | Artificial Lift

Service Companies Ready to Meet Challenges

From ESPs, PCPs and gas-lift systems to monitoring and automation services, the providers of artificial lift continue to develop innovative and cost-cutting technologies.



New oil wells share space with the old in the booming Permian Basin. *(Photo by Jennifer Presley, Hart Energy)*

By Ariana Benavidez
Associate Managing Editor

According to a March 2017 *Research and Markets* report, 96% of the oil wells in the U.S. require artificial lift from the onset.

The following section is a sampling of the leading players in the artificial lift market and an overview of their technologies and services for optimizing oil and gas production.

Key Players

AccessESP

Access ESP is a provider of rigless electric submersible pump (ESP) conveyance products. The company combined two technologies—a permanent magnetic motor and a side-pocket wet connect system—into one tubing-mounted permanent completion and a slickline retrievable assembly. Running and retrieving an ESP is now similar to running a production logging tool or replacing a gas-lift valve. The company's technology makes the retrieval and replacement of an ESP system through tubing, using conventional slickline processes and equipment. No rig is required.

The company has installed its conveyance systems in a variety of locations, primarily on the North Slope in Alaska, offshore Nigeria and in Italy.

In January AccessESP showcased its rigless ESP conveyance system in the industry's first pump swap for an operator on the North Slope of Alaska, a press release stated. "In two days, through a live well inter-

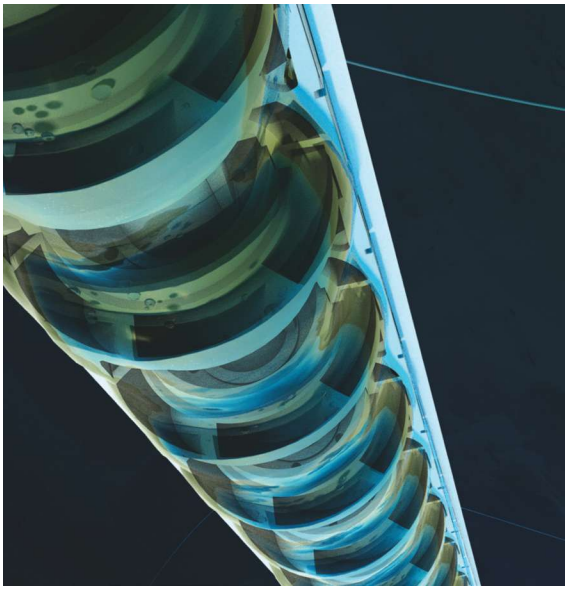
vention, the AccessESP system enabled retrieval of the existing ESP pump and the install of a newly optimized ESP pump using only a slickline unit, lubricator and a crane, marking the industry's first ESP pump swap on a commercial well," the release stated.

Baker Hughes

Baker Hughes' artificial lift products and services include electric submersible pumping systems (ESPs), progressing cavity pumping systems, horizontal surface pumping systems, gas-lift systems, surface electrical control systems, and monitoring and automation services.

Investing more than $60 million, Baker Hughes opened its Artificial Lift Research and Technology Center in 2014 in Claremore, Okla. This facility allows operators and engineers to create, develop and test solutions to potential problems as well as improve the reliability of artificial lift systems.

The company's FLEXPump series of ESPs is designed to provide operators with operational flexibility in dynamic well conditions to minimize ESP system changeouts and nonproductive time. The pumps can be applied to conventional oil fields, low flow-rate mature oil fields and unconventional resource plays. The pump designs reduce the total hydraulic thrust in both upthrust and downthrust conditions allowing the pumps to operate in a wider operating range. In addition, the FLEXPumpER extended-range pump provides a wide operating range for ESP systems in applications with rapid production declines.

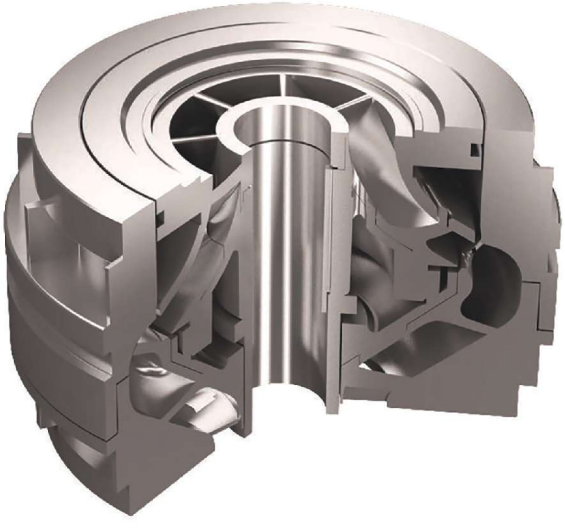


The FLEXPumpER extended-range pump provides a wide operating range for ESP systems in applications with rapid production declines. *(Image courtesy of Baker Hughes)*

In February Saudi Aramco and Baker Hughes installed the first TransCoil rigless-deployed ESP system, which is designed to help operators bring wells on production faster and lower the costs associated with installing and replacing ESPs, a press release stated. The inverted ESP system with the motor connected directly to a new proprietary power cable configuration eliminates the traditional ESP power cable-to-motor connection, which improves overall system reliability, a press release stated.

Borets

Operating in 24 countries, Borets is focused on the design, manufacture, sales and service of electric submersible pumping (ESP) systems. The company's products include permanent magnet motor (PMM) technology, which drive conventional and high-speed ESP systems as well as bottom-driven progressing cavity pumps.



The WR2 pump system is designed to handle harsh well conditions. *(Image courtesy of Borets)*

In March 2016 Borets released its high-speed Wide Range Wear Resistant (WR2) pump system, which is designed for the aggressive conditions often seen in unconventional wells. "The system has the ability to handle a wide range of production, abrasives and gas with the goal of extending runlife and minimizing well interventions," a press release stated. The system includes a high-speed WR2 pump, a PMM and a monitoring package.

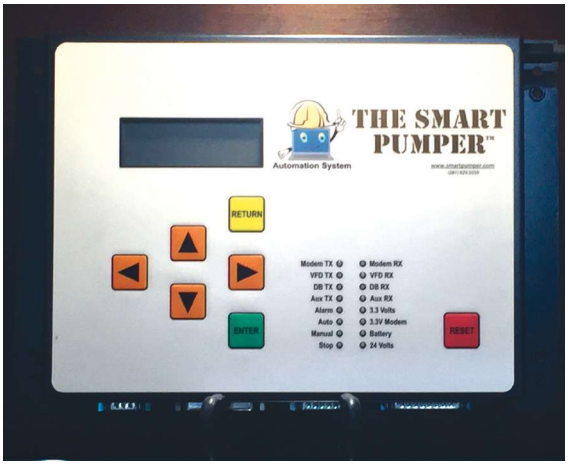
In addition, Borets offers a high-temperature system capable of operating in and designed to improve runlife in the steam-assisted gravity drainage environment.

Direct DriveHead Inc.

Direct DriveHead Inc. manufactures its patented low-cost Direct DriveHead for progressive cavity pump (PCP) operations as well as its patented Smart Pumper technology.

The Smart Pumper is a hybrid programmable logic controller/remote terminal unit device with built-in communication (SCADA covering 4G, 900 MHz, 802.11 and ethernet) for multiple applications within the oil, gas and water industries. This web-based system is ideal for greenfields where communication, operational control and monitoring of artificial lift devices together with the associated downstream facilities are critical. The Smart Pumper platform (a master controller of any variable frequency drive) deploys quickly and is proven to optimize production while reducing operational cost and HSE risk.

The company also provides PCPs, wellheads, fitting, valves and more.



The Smart Pumper is a hybrid programmable logic controller/remote terminal unit device. *(Image courtesy of Direct DriveHead Inc.)*

DistributionNOW

DistributionNOW (DNOW) offers custom rod pump systems and services, conventional and hydraulic pumping units, variable frequency drives, wellhead components, progressive cavity pumps (PCPs) and plunger lift equipment. The company also provides rod pump parts through Dura Products, a DistributionNOW company.

DNOW offers complete systems design and performance analysis of plunger lift, rod pump or PCP wells using design software (e.g., RODSTAR, SROD and C-FER PC-PUMP), technical expertise and practical experience.

The primary focus of DNOW's artificial lift division is reciprocating rod pump systems and services in the major shale plays, supported by 35 pump shops in the U.S. and 18 in Canada. The company has in-house plunger lift technical experts and three PCP test facilities.

The company provides "Best Practices for Rod Pumping Horizontal Shale Wells" workshops throughout the U.S. for its rod pump customers, where operators and DNOW rod pump experts can discuss specific issues and solutions.

Dover Artificial Lift

Dover Artificial Lift, part of Dover Corp.'s Energy Segment, offers a complete suite of artificial lift products. Dover has been involved in artificial lift for more than 50 years with its Norris sucker rods and related products. Within the last decade Dover transformed the company from a niche provider of sucker rods to a supplier offering all forms of artificial lift.

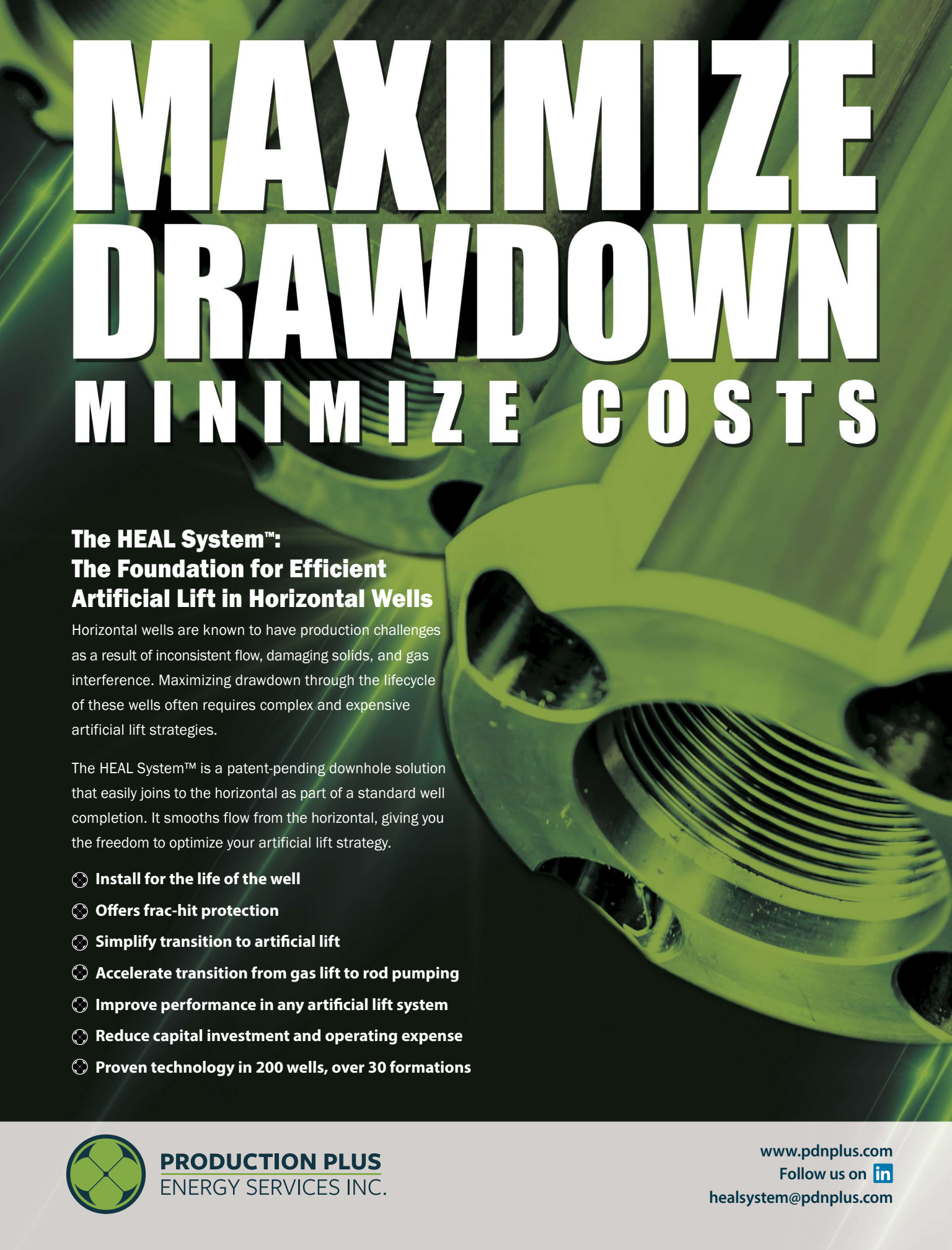
Dover has completed a number of product acquisitions. The company's acquisition of ACCELERATED in 2014 rounded out its portfolio by providing electric submersible pumps and hydraulic jet pumping. All products were designed for horizontal and unconventional wells.

Elite Multiphase Solutions

Elite Multiphase Solutions' (EMS) products address conventional electric submersible pump (ESP) production issues such as heavy oil, gas slugging, sand handling and unpredictable production decline characteristics.

EMS' V-Pumps are helico-axial pumps designed to handle jobs that technically challenge centrifugal style ESPs. Engineered for harsh environments, the V-Pump reduces the number of interventions and unpredictable production declines from high sand concentration, high gas volume fraction and gas slugging, which causes gas locking conditions. In particular, it also improves return on assets and increases the recovery factor with greater pumping capabilities in fields containing heavy oil, according to the company.

EMS' 538 Series V-Pump has an optimum operating range of 800 bbl/d to 6,000 bbl/d, and the 400 Series V-Pump has an optimum operating range of 500 bbl/d to 3,000 bbl/d. A unique gas handler will be released later in the year, which will expand the operating range of the 400 series to 4,500 bbl/d. The pump also eliminates the need for a sand filter and tail pipe, when sand is present, as well as the need for gas separators.



The HEAL System™: The Foundation for Efficient Artificial Lift in Horizontal Wells

Horizontal wells are known to have production challenges as a result of inconsistent flow, damaging solids, and gas interference. Maximizing drawdown through the lifecycle of these wells often requires complex and expensive artificial lift strategies.

The HEAL System™ is a patent-pending downhole solution that easily joins to the horizontal as part of a standard well completion. It smooths flow from the horizontal, giving you the freedom to optimize your artificial lift strategy.

- **Install for the life of the well**
- **Offers frac-hit protection**
- **Simplify transition to artificial lift**
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- **Improve performance in any artificial lift system**
- **Reduce capital investment and operating expense**
- **Proven technology in 200 wells, over 30 formations**

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Extreme Telematics Corp.

Extreme Telematics Corp. (ETC), a private corporation, designs and manufactures plunger lift controllers and sensors, wireless networks, solar panels and chemical injection controllers.

ETC's Sasquatch plunger velocity sensor is used to measure the surface velocity of a plunger before the impact at surface. The surface velocity is a key parameter required to calculate the kinetic energy of the plunger that is transferred to the spring and lubricator on impact. This information can be used for safety and predictive maintenance along with the kinetic energy rating of the surface equipment, which is required by the new American Petroleum Institute 11 PL specification.

ETC's Sasquatch plunger velocity sensor is used to measure the surface velocity of a plunger before the impact at surface. *(Photo courtesy of Extreme Telematics Corp.)*

In a February 2016 case study, ETC stated that one San Juan Basin producer had a well with a plunger being optimized to a target average velocity of 229 m/min (750 ft/min). After installing Sasquatch, the automation system recorded plunger surface velocities greater than 366 m/min (1,200 ft/min), which is 60% higher than the average velocity, according to the case study.

ETC's plunger product line also includes the ALiEn² plunger lift controller, Cyclops plunger arrival sensor and the Iris wireless bridge. ETC partners with several quality plunger lift service companies across North America that are equipped to sell, install and service ETC products.

Flotek

Flotek's Production Technologies division offers a variety of products and services for the oil field.

Flotek's new HYDRA-LIFT hydraulic lifting unit is designed for pumping reciprocating rod pumps more efficiently. HYDRA-LIFT products are offered for both single well and dual-pad applications.

The company's new Genius Series electric submersible pump (ESP) products and services offer a new digital platform for operators applying ESPs in conventional and unconventional wells.

Additionally, the SYNAPSE Drive in conjunction with the COGNITION software provides a communication and data management program for the life of the ESP produced well.

Other new services include Flotek's capillary installation and service, which uses Flotek-provided D-Limonene products to further protect the environment at the wellhead. The company continues to offer its proprietary PETROVALVE for reciprocating rod pumps with improved valve seating time and pump efficiency in deviated and gassy well applications. In addition, the company offers full service rod pump assembly and asset management in basin's throughout the Rockies region.

GE Oil & Gas

The GE Oil & Gas upstream portfolio includes a range of artificial lift technologies: beam pumping units, electric submersible pumping (ESP) systems, gas lift, hydraulic pumping units, progressive cavity pumps, downhole reciprocating pumps and surface pumping systems. Additionally, GE offers data management, downhole monitoring and sensors, and automation.

Among the company's recent developments are technologies to enable more efficient and cost-effective lift, including the Lufkin Well Manager (LWM) 2.0 rod pump controller for data-gathering, optimization and control capabilities, which enable field operators at the well to connect via Wi-Fi with a laptop, tablet PC and/or mobile devices to retrieve needed data. LWM 2.0 is available as part of the Field Vantage technology that applies GE's Predix platform to help operators visualize well, field and operations data for smart deployment of resources and decision-making, allowing users to predict issues with their lift systems.

Additionally, the company's Ground Fault Immune gauge system runs a power and commu-

nication system to reduce monitoring system failure when a ground fault occurs on the ESP cable, giving operators the ability to maintain continuous well surveillance.

GE's Vector Plus variable speed drives allow operators to gradually increase ESP motor speed and remotely adjust ESP speed from the surface with easier use and improved intelligent control capabilities, according to the company.

GE's REGEN technology is designed to draw cleaner power from the line and recover energy created during negative pump cycles.

Global Production Solutions Inc.

Global Production Solutions' (GPS) artificial lift products and services include electric submersible pumps (ESPs), 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 proprietary program to optimize water transfer and disposal costs. In testing, the company said it has reduced electric utilization 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. 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.

GPS also has developed a new variable speed drive controller/user interface that will be retrofitable to most variable speed drives. The interface has several advanced features for downhole and surface pumping applications.

Halliburton

Halliburton's artificial lift portfolio includes electric submersible pumps, surface rod pump, progressive cavity pumps and the InteLift remote monitoring and optimization system. Each product is designed to maximize wellbore production at a variety of depths, volumes and conditions over different stages of the well life cycle. The company also provides artificial lift installation, maintenance, repair and testing services.

Halliburton's REDLift XT production system is a total system concept that delivers artificial lift applications, which are combined with LIFTRightSM. The company's electric submersible systems (wide-range pumps, tougher motors and gas mitigation products) are designed to deliver better total well performance in unconventional and mature fields. The LIFTRightSM service delivery model is centered on total well performance and increased reliability—from designing and executing the right lift application, along with optimizing and reviewing well performance, to analyzing post-job results for continuous improvement, the company said.

The REDLift XT ESP production system is designed to provide reliability, durability and efficiency. *(Image courtesy of Halliburton)*

Liberty Lift Solutions LLC

Liberty Lift provides artificial lift products including long stroke rod pumping units, high-efficiency and enhanced geometry beam pumping units, gas-lift systems and hydraulic jet pumps.

In 2016 the company completed three expansion projects to further enhance its presence in the installation and service of artificial lift equipment. Liberty Lift completed the construction of a new facility in Bakersfield, Calif., consolidating two service operations in Bakersfield and Taft, and also expanded farther into the Permian Basin with the opening of a service center in Hobbs, N.M. The company also opened a gas-lift shop in Oklahoma City, Okla., and will soon add a similar facility in Williston, N.D.

In January 2016 Liberty Lift released its XL model 320-500-306 long stroke rod pumping unit. The unit operates at low speeds with both

Liberty Lift's XL 366-in. stroke units are well-suited for work in deviated, deep, high-volume wells. *(Photo courtesy of Liberty Lift)*

variable and constant velocities, providing fewer strokes per minute with high production rates, which assists in reducing stress on the reducer and sucker-rodstring.

In March 2017 the company added a 366-in. stroke length version, the XL 366, to its product line. The unit comes with numerous standard features, including the Unit Sentry that detects potential operating abnormalities, pausing or stopping the unit when alerted. The XL 366 incorporates an efficient, clean oiling system for internal parts and safety features to protect operating personnel and the environment

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. This provides "a solution for deviated or horizontally drilled wells at depths ranging from 1,000 ft to 18,000 ft [305 m to 5,486 m] and well production up to 20,000 bbl/d, with high flowbacks of contaminated production fluids," the company said on its website.

National Oilwell Varco

Artificial lift technologies provided by National Oilwell Varco (NOV) under the NOV Completion and Production Solutions segment include hydraulic rod pump systems and progressing cavity pump systems as well as production hookup equipment, tubing rotators, automation and monitoring.

Released in first-quarter 2016, NOV's Hercules electric rod rotator (ERR) is actuated using an electric motor coupled to a control system or standalone control box. By using an electric motor, the user no longer needs to install a traditional mechanical arm and cable. The rotation sensor, coupled with the control box, monitors performance and alerts operators when failures occur.

NOV also purchased of a line of completion tools that support horizontal multistage fracturing from Trican Well Service Ltd. in summer 2016.

Additionally, NOV developed the Smart Rod Rotator, which builds upon the technology used in the Hercules ERR, to address premature wear due to wellbore deviations. The Smart Rod Rotator automates the routine of checking rod rotator integrity and, when combined with rod pump controllers (RPCs),

NOV's Smart Rod Rotator (center) automates the routine of checking rod rotator integrity and allows remote monitoring and alarm capabilities. The Hercules ERR (inset) eliminates the need to install a traditional mechanical arm and cable. *(Photo courtesy of NOV)*

allows remote monitoring and alarm capabilities, reducing onsite time and maintenance. The programmable logic controller (PLC) will issue a fault or alarm to the RPC if a certain number of rotations does not occur within a user-specified time frame. The PLC also sends a signal pulse, which is counted and stored in a viewable register, to the RPC every time a complete rotation occurs. Rodstring rotation, used in conjunction with rod guides, removes paraffin from inside the production tubing and distributes wear evenly for rods and rod couplings, in turn extending the period between workovers and minimizing downtime.

Novomet

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

The company's ESP offerings include downhole equipment, surface equipment and scale preventers and filters. Released in 2016, Novomet offers a rigless cable-deployed, 2.17-in. outer diameter ESP system designed to fit inside of 2-in. tubing. This ESP system was designed to reduce operation costs for oil and water production.

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.

Priority Artificial Lift

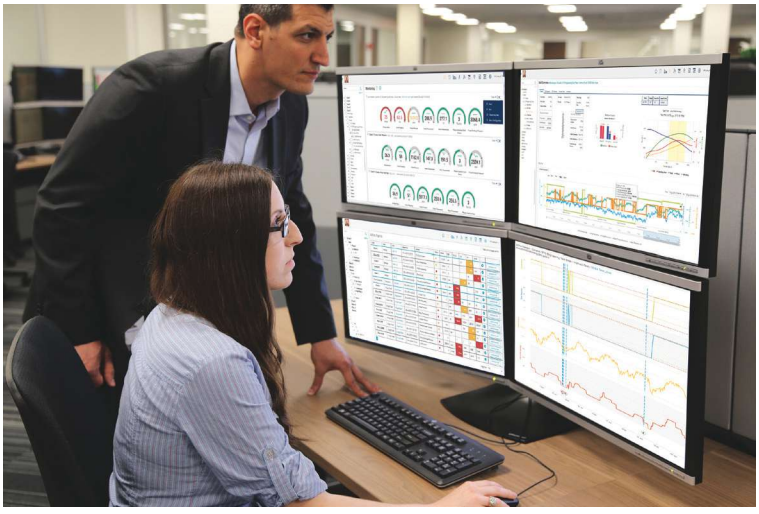
Priority Artificial Lift (PAL) offerings include gas lift, plunger and completion tools and technologies. PAL is American Petroleum Institute (API)-certified and is the only API-certified company to design and manufacture gas-lift and plunger lift equipment in the U.S. and under one roof, according to the company.

PAL experts strive to maximize production throughout all facets of the life of unconventional wells, from initial high-pressure completions to low-pressure depleted wells. The company uses its newly designed conventional high-pressure gas-lift equipment (10,000-psi rated) to accommodate gas-

lift installations on initial completions and in highly developed areas where high-pressure offset fractures are likely. As the wells deplete, PAL has an array 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.

Schlumberger

Schlumberger has a comprehensive artificial lift offering that includes electric submersible pumps (ESPs), a rigless ESP replacement system, gas lift, horizontal surface pumps, sucker rod pumping, progressive cavity pumps (PCPs) and production optimization technologies.



Dedicated engineers are based at one of the many Schlumberger Artificial Lift Surveillance Centers where they monitor alarms 24/7 year-round. *(Photo courtesy of Schlumberger)*

In March 2017 Schlumberger commercialized the 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.

Another recent release is the company's ZEiTECS Shuttle rigless ESP replacement system, an alternative deployment technology that "shuttles" standard ESPs through tubing on wireline, coiled tubing or sucker rods without a rig or hoist. This technology minimizes production deferment, operating costs, HSE risks and disruptions to operations.

"Schlumberger offers integrated artificial lift solutions to manage the production life cycle from start to finish. The complete suite of technologies and services enable operators to seamlessly switch from one lift methodology to another for maximum well performance throughout the well's life," the company said.

Schlumberger and Cameron merged in April 2016. The Cameron artificial lift technologies and services, including PCP and CAMLift hydraulic pumping unit technologies, are now part of Schlumberger Artificial Lift Solutions.

Sercel-GRC

Sercel-GRC provides downhole pressure/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 (PCPs) as well as gas-lift, sucker rod pump and jet pump applications.

Sercel-GRC's Spy Pro ESP gauge with uCommand technology features a waterproof connection design. The gauge also offers 11 channels of sensor data, including a well fluid ingress measurement that might indicate pending ESP motor failures. The gauge can be paired with Sercel-GRC's Datalogger 4200S surface readout to enable uCommand data optimization. Spy Pro's uCommand technology offers two-way interactive control of all 11 measured parameters. The operator can increase the data sampling rate by communicating with the gauge from the surface, selectively optimizing individual parameters as reservoir conditions change. Changing the sampling rate occurs in real time while the ESP is running. Pressure buildup and drawdown tests can be conducted with 2.5-second resolution, without losing regular updates of the other gauge parameters.

The Spy Pro ESP gauge is compatible with all ESP providers, including slimhole applications with a 3.75-in. equipment diameter. The Spy Pro product family includes multiple configuration options, including corrosion-resistant metallurgy, various motor adapters and discharge pressure measurement.

Summit ESP

Summit ESP provides electric submersible pumping systems (ESPs) and surface pumping systems as well as a variety of products and services to meet ESP needs. Summit ESP has offices in every major oil and gas play in the continental U.S., Alaska and Canada, and the company offers extended range pumps, advanced gas handling, abrasion-resistant technology, harmonic mitigation variable speed drives and high-performance motors.

Summit ESP completed its 7,000th ESP installation during fourth-quarter 2016 on a well for Apache Corp. (the Andrews Unit 550 in Andrews County, Texas) at a setting depth of 2,561.5 m (8,404 ft).

In 2016 the company's 400 series Tiger Shark XRange (XR) pump with Liberator vortex gas separator and Defender seal helped an operator in Texas draw its fluid level down from 731.5 m (2,400 ft) to 137 m (450 ft) while also increasing production from 100 bbl/d to 420 bbl/d of oil.

In another instance, Summit installed a Tiger Shark XR (extended range) pump to draw down fluid levels and optimize productions for an operator in Louisiana. Revenue doubled to $10,000/month ($45/bbl of oil) when production jumped to 16 bbl/d of oil.

A Summit truck prepares for cable spooling at the company's Ross, N.D., facility. *(Photo courtesy of Summit ESP)*

Superior Energy Services

Superior Energy Services has more than $2 billion in revenues and more than 8,000 employees worldwide. The company 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 notability being the dart-style plunger and the patented Pacemaker plunger as well as 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 onsite 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.

Tenaris

Tenaris, a supplier of tubes and related services for the energy industry, has manufacturing facilities in more than 15 countries.

Tenaris recently released its AlphaRod series of sucker rods, featuring rods manufactured with enhanced steel grades designed for a long life in demanding requirements, a March press release stated. The AlphaRod series includes two steel grades, which cover a wide range of applications. The AlphaRod HS High Strength and AlphaRod CS Corrosion Service are designed to handle increased service loads and overcome fatigue and corrosion-fatigue problems in beam pumping and progressive cavity pumping applications.

The Rig Direct Academy allows operators to witness how Tenaris products perform in different applications. *(Photo courtesy of Tenaris)*

In December 2016 Tenaris expanded its presence in the U.S. with the opening of its new service center in Midland, Texas. The service center handles the storage, inspection, rig preparation and delivery of oil country tubular goods, accessories, sucker rods and, in the near future, coiled tubing. The service center will complement Tenaris' $1.8 billion seamless pipe mill in Bay City, Texas, which will be inaugurated in late 2017.

In June 2016 Tenaris began operations at its new Rig Direct Academy, a training and testing center located in Veracruz, Mexico. The test rig facility allows operators to see how Tenaris products perform in different applications.

Unico

Unico Inc. provides variable frequency drives and controls for electric submersible pumps, hydraulic pumping units, progressive cavity pumps (PCPs) and sucker rod pumps. The company's mechanical lift systems include its linear rod pumps, PCPs, crank rod pumps and hydraulically actuated pumps. The company also offers pump controllers and remote monitoring.

In April 2016 Unico released its latest remote monitoring product, UWS Hatch Sense. Together with a Unico UWS Gateway, the system allows the status of tank hatches and other safety mechanisms to be remotely monitored by the GMC system or a SCADA system.

In addition, Unico's SRP Well Report provides well operators with one-button access to surface and downhole pump DynaCards and other data stored in a well powered by a Unico artificial lift drive. Operators can generate a complete four-page well report, produced in as little as 25 seconds, at the click of a button.

The company's Synthesis intelligent pump controller simplifies pumping systems by integrating essential motor, logic and process control functions into a single economical unit. It is designed to provide superior pressure, flow or level control, optimal efficiency and comprehensive protection for the pumping system.

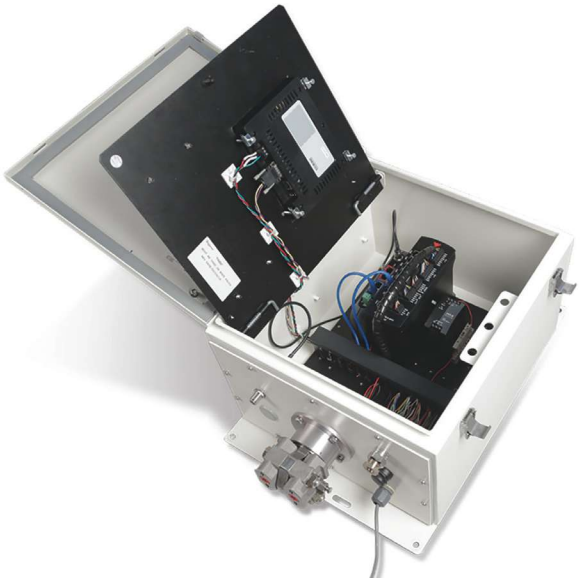
Unico is a wholly owned subsidiary of Regal Beloit Corp., a worldwide manufacturer of mechanical and electrical motion-control products.

Weatherford

Weatherford provides products and services for every form of artificial lift, including reciprocating rod lift, gas lift, jet-pump lift, hydraulic piston-pump lift, plunger lift, progressing cavity pump lift and capillary technologies. Weatherford also provides hardware, sensors, software and advisory services for production optimization.

The company's new 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 filter to keep damaging sand out of the plunger-barrel sealing surfaces.



The WellPilot ONE controller is in field testing in preparation for commercial release later this year. *(Image courtesy of Weatherford)*

In addition, the company is releasing a new, single-platform production optimization tool that is designed to maximize asset value. The software platform enables asset-wide monitoring, predictive performance analysis based on historical and real-time data, and proactive field management that is designed to help operators to maximize production and reduce cost per barrel.

Zedi Inc.

Zedi is an oil and gas technology and services company that offers software, automation, artificial lift, measurement and field operations technologies.

Zedi's SilverJack artificial lift system tandem setups can operate in extreme temperatures. *(Photo courtesy of Zedi)*

The Zedi SilverJack artificial lift system is an advanced hydraulic pumpjack with a local graphics-based optimization controller and Zedi Access web-based data management system that provides remote monitoring, alarming and control. This allows both local and remote optimization and the resolution of common rod pumping problems without site visits or labor-intensive manual processes.

In addition, Zedi SCADA is a web-based open system that works with any digital monitoring hardware to deliver real-time operational data, allowing users to remotely view and control field equipment including any artificial lift solution.

In February 2017 the company announced that its Industrial Internet of Things platform surpassed 1.25 million sensors monitored, "with exceptionally strong growth through the last quarter of 2016, and the first five weeks of 2017," a press release stated.

"Zedi has architected a scalable, secure, high-performance platform serving the monitoring needs of hundreds of customers in the oil and gas industry in over 20 countries," said CTO James Freeman in the release. "Our platform interfaces to countless different devices from a variety of third parties, giving our customers opportunities to make visible data from controllers, RTUs [remote terminal units] and other instrumentation in the field."

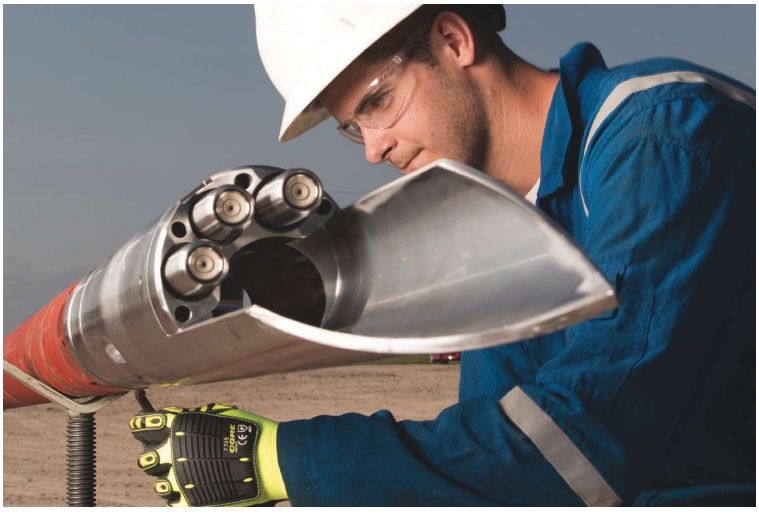
In October 2016 Zedi added Precision Analysis to its team. Precision Analysis is a full service hydrocarbon and environmental laboratory that provides analytical testing and measurement services to the oil and gas industry. ■

Driving the Future of Artificial Lift

While cutting-edge hardware is often a prime mover of the technology needle, for the future of artificial lift, contractors are looking to advancements in digitalization and automation.

By Blake Wright
Contributing Editor

Experts are predicting the next step-change in the evolution of artificial lift will not be hardware-intensive but rather the ability of service providers to harness the massive amounts of data that new tools are providing to better forecast reservoir behaviors and afford more timely responses to changes and thus to lift recipes, if required. The digitalization and further automation of artificial lift systems going forward is where most see the near-term benefits emerging, while equipment continues to evolve to best capitalize on those drivers.



The plug-and-play design of the ZEiTECS Shuttle rigless ESP replacement system enables any standard ESP assembly to be retrieved and redeployed without a rig using wireline, coiled tubing or sucker rods. *(Photo courtesy of Schlumberger)*

"At its core artificial lift is a tool available to enable production," said Ricardo Gomez, president, Production Solutions, GE Oi & Gas. "Born out of necessity for wells that stopped flowing naturally, it has become part of a holistic suite of tools and disciplines to maximize production and reduce the cost per barrel. The future of artificial lift is centered around digitalization and the ability to use data to drive the right lift technique at the right time to enable low-cost oil production, extend equipment runlife and more efficiently integrate into the production management system."

The influx of big data will allow operators and their service providers to be more accurate when predicting future production patterns, which could mean more timely responses to the needs of wells, both conventional and unconventional, to shift between different artificial lift methods.

"Automation will be the key to the future of artificial lift," said Khaled Elsheikh, vice president of marketing and technology, Schlumberger Artificial Lift Solutions. "The world is becoming more and more digital every day, and despite the advances in big data, analytics and machine learning, these advancements have yet to really take hold in the world of artificial lift. It is not an easy challenge to crack as upstream oil and gas production has many variables that are difficult to model; it is even more difficult to predict what is happening downhole and ultimately be able to automate proactive action. In the not-too-distant future we will start to see real progress being made for automation within the artificial lift space."

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To make the necessary technology advances in reliability, efficiency, environmental sustainability and safety requires a fully digitalized and automated value stream that stretches from initial R&D to the field, according to Baker Hughes. The contractor even sees the manufacturing process as being revolutionized with processes like additive manufacturing, which will allow the company to deliver equipment customized for every well in days, not weeks, and eliminates the need for costly inventory.

"The basis for this 'digital age' is data," said Ignacio Martinez, director of technology, Artificial Lift Systems at Baker Hughes. "It's time we start asking ourselves some fundamental questions. Are we collecting the right data? Are we evaluating the data appropriately? Are we extracting the maximum value from the data? Automation and visualization is the next big revolution in the production phase. We've been talking about the 'digital oil field' for years, and advancements have been impressive in the exploration arena, but we still have a long way to go to match that digitalization after a well is on production. The key to success is data. Gathering richer datasets to improve the longevity of artificial lift systems will require a step-change in downhole sensors that are reliable and more cost-effective and that provide the right information."

Down market drivers

Cost-effectiveness swings even more into play in a down market. Fuel surpluses have kept prices in check. Crude value for a barrel of West Texas Intermediate has toppled from around $100 in the summer of 2014 to about half that figure (~$48 as of May 1). Volatility of that nature can put companies in jeopardy and projects on the chopping block. As the bottom line shrinks, operators are less inclined to move forward with ambitious greenfield development and instead turn to near-infrastructure opportunities and how to get the most out of the producing assets they already have.

"The focus on existing wells and maximizing production through efficient asset utilization has given way to an opportunity to elevate the level of scrutiny put on oilfield optimization through monitoring, analytics and action planning," said Gomez. "Instrumented wells and equipment can now communicate with enterprise software platforms that help operators improve equipment run-life and reduce operating expenses over the life of the well. Additionally, the rise of data science in the oil field has opened the door to process and system improvements needed in the drilling phase to further improve ultimate recovery and total cost of operating a well over its life."

Cost is driving production decisions today, and for artificial lift that means more efficient, cost-effective and reliable solutions. Operators are talking about the total cost of ownership of the asset and capital efficiency—how they can extend mean time between failures, reduce the costs associated with repairing damaged equipment and limit the time and expense of changing lift types as well conditions change, according to Weatherford.

"Lift decisions are now made based on economic analysis rather than the comfort of using the same lift type that had always been used in that field," explained Scott Campbell, vice president of sales and marketing, Artificial Lift Systems at Weatherford. "Our clients are also more focused on lift solutions that will provide flexibility, which drives us to be more creative about how we transition between lift types. One international trend we have seen increasingly is the use and application of rigless artificial lift systems to reduce workover costs and total nonproductive time. Essentially, rigless artificial lift systems are those deployed using coiled tubing, wireline or a continuous-rod system such as Weatherford COROD continuous sucker rods rather than with a workover rig. Rigless options are especially important in some regions internationally where clients may not have access to a highly mobile, efficient workover fleet that is able to deploy rapidly when a well goes down or maintenance or repair is needed. By offering rigless options, we can save operators weeks if not months of downtime."

Efficient changes on-the-fly

Several different types of artificial lift might be employed throughout the lifespan of an unconventional well. In a place like the Wolfcamp play in West Texas, a well might be equipped initially with a jet pump or electrical submersible pumps (ESPs) to accommodate high flush rates but then be converted to gas lift after a few months and then to beam pumping after that, when production has declined to an optimal level.

Unconventional plays have changed the game for artificial lift. While the current situation certainly is not efficient, it is not likely to change radically in the near future due to limitations of each artificial lift option. Incremental improvements have been made to extend the operating range and prolong the viability of ESPs in unconventional wells, but that does not address the underlying inefficiency of

the status quo and, according to Baker Hughes, the industry is "screaming" for a better solution.

"Obviously, the optimal state would be one efficient, reliable lift system for the life of a well," explained Martinez. "The key words in that statement are 'efficient' and 'reliable.' And that's very difficult to achieve in wells where the downhole conditions change dramatically over time. The more likely nearer term solution is finding ways to make it more economically efficient to change out artificial lift systems. Alternative deployment research today is focused on offshore or remote areas where intervention costs are exorbitant, but as we learn more about this technology we will find ways to make it economically viable for land wells. That's the evolutionary arc of technology in our industry."

When dealing with subsurface like the Permian Basin, where wells can experience up to an 85% decline in production within their first year, changes in lift types over time are a necessary step in maintaining commercial flows.

"In addition to dramatic changes in production rate, there are other challenges that drive operators to look at different forms of lift," said Campbell. "During the initial flowback and cleanup period, which lasts one to three months, these wells produce sand and have high gas-to-liquid ratios. They also often lack the necessary gas compression and electricity infrastructure during this early period, all of which adds up to a worst-case scenario for most forms of lift."

One creative solution to these common problems is to deploy a combination string of gas-lift equipment and a hydraulic jet pump on the initial tubing completion, according to Weatherford. With that completion in the hole, the operator has the ability to use jet pumps for initial cleanup of sandy and remote wells. After cleanup and when needed, gas lift can be initiated without a workover. This is a very common practice used today by several major operators in the Wolfcamp.

Weatherford's Rotaflex long-stroke pumping units have been successfully installed on wells that produce fluid volumes of up to 1,000 bbl/d. *(Photo courtesy of Weatherford)*

"The key to this system is flexibility," explained Campbell. "A combination string gives the operator the flexibility to use the right lift method at the right time with minimal expense and no additional workover costs required. The majority of the liquid-rich shale wells in the US will end up on reciprocating rod lift. To effectively move to this final form of lift earlier in the life of the well, Weatherford will often deploy the Rotaflex long-stroke pumping unit, which has relatively low maintenance costs when compared to electric submersible pumps. Rotaflex pumps can move

higher volumes of fluid than most people expect, and have been successfully installed on wells that produce fluid volumes of up to 1,000 bbl/d. The Rotaflex unit can remain on a shale well through a wide range of production rates, from initial installation just after completion through the life of the well."

Help could be on the way, according to GE. There are a number of technologies on the horizon that may be able to handle wider operating ranges at economically feasible efficiency rates. In the meantime, even with the costs associated with changing lift types over the life of the well, a well-timed artificial lift method change-out can quickly pay for itself in terms of improved recovery.

"In order to minimize the number of lifting systems that must be installed and maximize operating efficiency, the industry will need to adapt data-driven software solutions that can integrate reservoir models, production conditions, machine health data, and process or operating information to recommend the types of artificial lift needed for the life of a well and identify the appropriate timing for a lift methodology change," said Gomez. "Integrated, equipment-agnostic software will enable a front-end planning view for long-term artificial lift method selection, installation and monitoring, improving operator cash flows, increasing output and reducing the cost per barrel."

Material changes

One piece of tech that is changing within existing artificial lift systems is the material components. Better, stronger material affords a longer-lived product and one that can stay in service longer than one that might be using older materials that might have to be taken offline for repairs.

"Materials science is critical to increasing runlife and in some cases just to permit the artificial lift system to even be a viable option in particularly harsh downhole environments," said Elsheikh. "For example, new elastomers are now being used with CO_2 flood fields to ensure protectors in ESPs can withstand the corrosive environment and protect the motor. New elastomers are being developed in cables such as the recently introduced 8-kV REDA MAX ESP electrical power cable. This cable was designed to run a high-voltage subsea ESP system with one leg grounded to ensure the ESP could continue to run and extend its life in this high-workover-cost environment. The industry also continues to make advances with tough coating materials such as the Kudu Tough Coat corrosion- and abrasion-resistant rotor coating designed to improve resistance of progressive cavity rotors in corrosive and abrasive environments."

The aim of research in materials science, like other areas, is to drive more reliable technology and lower life-cycle costs. While breakthroughs might still be in the distance, work being done today is fueling tomorrow's improvements and could result in a step-change in longer lived artificial lift equipment.

Baker Hughes' CENesis Curve tight-radius production system is designed to pass through a 15-degree per 100-ft bend section in deviated and horizontal wells, allowing operators to land the ESP system closer to the pay zone to maximize production and reserve recovery. *(Photo courtesy of Baker Hughes)*

"Operators routinely ask for five-year runlife for ESP systems," said Martinez. "That's equivalent to running your car for 500,000 miles without turning it off or changing the oil. Not even a performance car of the highest order can do that. But we are asked to do just that every day and, depending on the downhole environment, we are succeeding. And many operators are pushing for ESP systems that can run for 10 years. That will require a shift in our thinking, and materials science is part of that shift. Today we still focus on making improvements to the metallurgy we use, but we have to start thinking about entirely different materials like ceramics, shaped memory alloy or thermoplastics, which haven't been extensively studied in our industry.

"Innovative new materials will also change the landscape of how we manufacture products. Imagine a world where equipment is manufactured specifically for every well's unique production environment and delivered in days, not weeks. I believe that will be possible in the not-too-distant future, and the equipment won't be made of standard metals." ■

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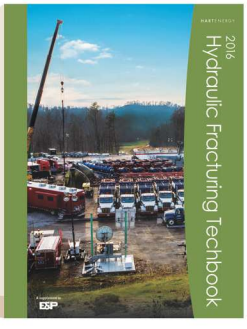

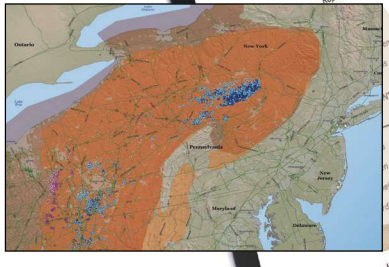

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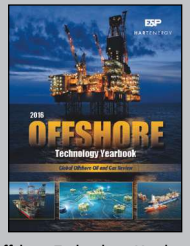

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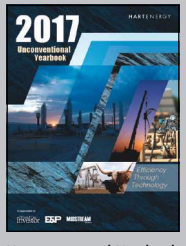

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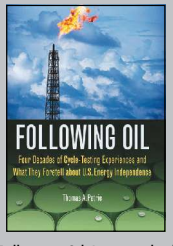

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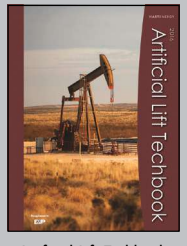

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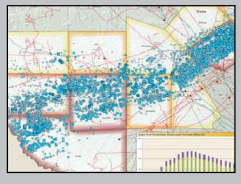

Eagle Ford Shale Map

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Full Life Cycle, Extended Life Are Goals for Artificial Lift Technology

There is a shift in the industry's mindset regarding artificial lift other than rod pumps, and companies are starting to explore and perfect it.

By Scott Weeden
Contributing Editor

Until about five years ago, electrical submersible pumps (ESPs) were typically used in rather benign applications—low gas volume, minimal abrasives and high water cuts. The historical default has always been the sucker rod pump. Now companies are enhancing many of the artificial lift technologies and using cloud technology to redefine how those technologies impact production efficiency and effectiveness.

"We're very focused on edge computing today as well as cloud-based analytics," said Steven Seale, director of automation for artificial lift for Weatherford. In the firmware in the control logic of the controller, the company has embedded software for all lift types to support the full life cycle of the well.

Matt Young, sales manager, Flowco Production Solutions, noted, "One of the challenges that everybody is really facing in the artificial lift market would be the unconventional horizontal wells. It is the rapid decline in production and productivity of the wells. We're really trying to size a long-term artificial lift for those applications."

"Today we're looking at how to make the cable survive a longer period—say a 10-year life versus a typical ESP life of two to three years. If we're going to have components we can run in and out of the well when they fail, then we need to have cable that can survive for years," said Greg Nutter, vice president operations and QHSE for AccessESP.

"We have many clients that like ESPs because they like the accelerated drawdown of the well that they get with ESPs before they eventually move the wells over to beam units," said Robin Roberts, director of business development for Summit ESP.

While the majority of wells with artificial lift use rod pumps, artificial lift vendors are devising new ways to combine old technologies and develop new technology to match the ever-evolving production in the oil patch.

Full life-cycle wells

Weatherford supports all lift types plus flowing wells. From an analytics perspective the company has invested in enhancing its software offerings, including cloud-based systems that collect data from internet-connected devices in the field and apply different algorithms and analytic engines to provide predictive output, explained Seale.

"When you look at diagrams for the industrial internet of things (IIOT), typically they include cloud computing, and we relate to things being in the cloud. However, because of limitations in communication infrastructure, edge computing at or near the well will be here for a long time to come," he said.

Examples of edge computing include the thousands of controllers and remote terminal units that are already installed today at or near the well. These controllers manage and control the lift equipment and stream data back to the control room where the SCADA platform is installed. These SCADA systems sometimes reside in the cloud.

One of Weatherford's newest edge devices, called WellPilot ONE, is scheduled for release in fourth-quarter 2017. "With WellPilot ONE we are essentially creating a new way of thinking about artificial lift management. Historically there has been a whole list of different controllers and separate end devices for use as the well moves to different forms of lift," Seale said.

The company has consolidated its firmware and control algorithms as part of its move to a single piece of hardware. The WellPilot ONE controller is currently in field trials. It is what the company calls "a life-of-the-well controller."

The controller is installed one time when the well starts flowing. It is then used for all measurement and data collection, including the tanking, temperatures and pressures, Seale said.

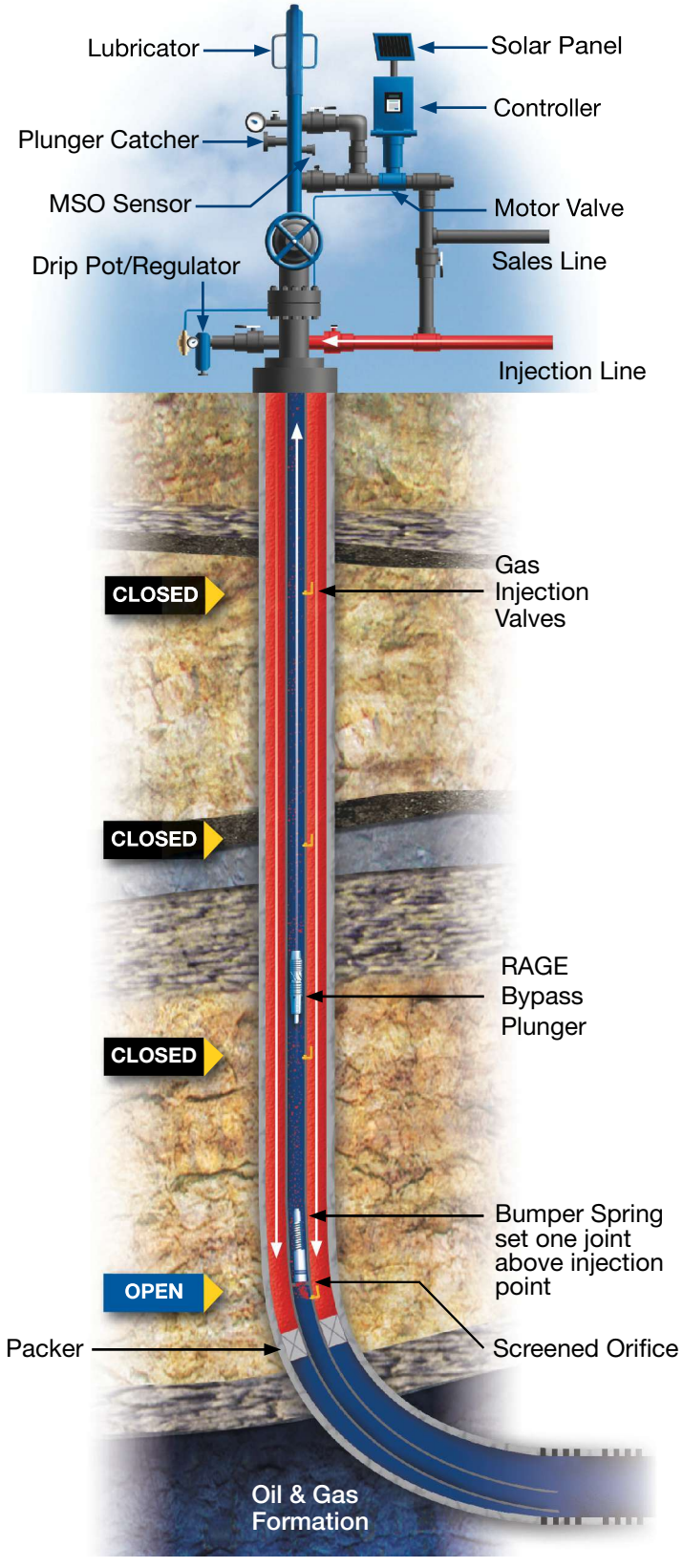
"Later in the life of the well, when it moves to gas lift, for example, the operator can use the same piece of hardware. All we have to do is relicense the controller and set a software license key, and the controller can do what we call gas-lift control or gas-lift optimization," he explained.

When the well's bottomhole pressure (BHP) goes down too low, the operator moves to a rod lift using the same controller. "We simply interchange or update the license to rod-lift control capability and install a variable-speed drive with the pumping unit. Then the operator can continue using the same piece of electronics with WellPilot ONE as a rod-pump controller," Seale said. "We can offer up to 50% savings by reusing the same electronics."

Combining plunger lift, gas lift

For the past two to three years, Flowco Production Solutions has been pushing the envelope on the high end of how much production it can get out of wells with either plunger lift, gas lift or a combination of the two, Young said.

Plunger lifts started back in the 1930s and began kicking in during the 1960s, 1970s and 1980s. Conventional plunger lift was notorious for only producing about 50 bbl/d. Now Flowco is building plunger lifts that can produce about 500 bbls/d of fluid, explained Mitch Boyd, managing partner, plunger lift for Flowco.



Gas-assisted plunger lift is a highly effective means to help further reduce the flowing bottomhole pressure not only on aged gas-lift wells but also new high-rate wells. *(Image courtesy of Flowco Production Solutions)*

When the unconventional wells kicked in during the mid-2000s, the industry was faced with an answer to artificial lift as well as more challenges. The interest in plunger lift started in the Barnett Shale. "In 2⅜-in. tubing, up to 150 bbl/d was normal in the Barnett. Out in the Permian Basin in 2⅜-in. tubing we've moved up to 300 bbl/d. We're able to move a lot more liquids because the plunger can fall through flow or because it has a bypass in it," Boyd said.

"We've got some wells up to 600 bbl/d, but on average in 2⅞-in. tubing it is 200 bbl/d to 400 bbl/d. It requires gas-assisted plunger lift on the majority of the wells," he added.

"With gas-assisted plunger lift we really are able to achieve lower BHP as well as follow production decline for the first year or two when they're at more than 600 bbl/d down to years five through 10 where they're now producing 100 bbl/d to 150 bbl/d with relatively little maintenance to the actual artificial lift system," Boyd said.

The plunger lift system can be used for paraffin control also. "We did a well in the Permian Basin a few months ago that was about 700 bbl/d. However, the plunger system was actually being used for paraffin control," Young said. "Once we put on the system we didn't hurt production at that rate, but we were able to keep the paraffin clean."

This equipment could be placed on location for the life of the well with scheduled maintenance so the equipment stays in place as needed.

"We've basically combined two technologies to provide a lower cost of artificial lift compared to the higher maintenance that goes along with rod pumps and things of that nature," Young added.

Using slickline for pump removal

In a typical ESP well an operator has to use a rig to pull the tubing to get the failed ESP out of the well. AccessESP has a system to retrieve and replace the ESP through the tubing using slickline. Slickline units are an order of magnitude or even less expensive than a typical rig operation because of less time needed to replace the equipment, Nutter explained.

Slickline units can't compete in areas where rigs are cheap and plentiful like in North America, where an operator can call and get one the next day. However, if rigs are scarce or the wells are in remote areas, then the slickline retrievable units can be cost-effective.

"We don't see a lot of issues with slickline. One big difference is that if there is a problem and you can retrieve the ESP through tubing, we can solve the problem without bringing the rig back," Nutter said.

AccessESP doesn't provide pumps or other ancillary equipment like surface controls. "Whatever equipment they have at the wellsite—regardless of the vendor—is what we end up using. We don't require any special surface equipment," he added.

Competitors have systems that come in one single piece that might be 150 ft long. "Our technology breaks into four pieces, each one less than 50 ft long. We can make an installation where we have pressure control throughout the entire installation," Nutter said.

"There are a couple of important things to notice. We have the system broken into four pieces, and those are broken into components that are easily handled by the slickline pressure control equipment. We use our permanent magnet motor and our plug-in retrievable technology," he noted.

The top of the company's Access375 retrievable assembly is a tubing stop. It's about a foot long and weighs about 20 lb. The next piece is the tubing pack-off. It has a rubber donut that seals to the inside of the tubing. "When we remove

New High-performance Resin to Reduce Failures in Challenging Environments

By Zach Stearman and LJ Guillotte
Lightning Rod & Pipe

Corrosion-enhanced abrasive wear is a common cause of failure in sucker rod systems. The combination of high side loads caused by deviation and the presence of corrosive chemicals creates a very difficult environment for operators. Reciprocating rod pumps are the most popular method of artificial lift due to many technical and practical advantages, but these problems are costing operators hundreds of millions of dollars each year.

Traditionally, rod guides have been the common method of addressing deviation-related failures in rod-pumped wells. The effectiveness of rod guides, however, greatly varies. The turbulent flow caused by a reduction in area around the rod guide can increase corrosion and lead to premature failures. In severely deviated wells, it is common to have sections of six or eight rod guides that significantly increase the cost of the rod string while adding considerable amounts of friction. For these reasons, operators have begun to seek alternatives to rod guides in their deviated wellbores.

Thermoplastic liners have been used to reduce wear and corrosive effects in downhole oil and gas applications for more than 20 years. Although originally intended for water injection and disposal wells, the technology quickly gained acceptance in beam pump wells to reduce the rate of rod on tubing wear. Initially, liners were manufactured from a high-density polyethylene (HDPE). HDPE is a very versatile plastic that provides a moderate level of protection against corrosion and abrasive wear, but the maximum continuous operating temperature of 160 F limits its potential applications.

High-performance resins are now being extruded to address the challenges that were seen with HDPE and other low-temperature resins. Not only do high-performance resins provide higher working temperatures, they also perform better against corrosion, have lower coefficients of friction and stand up better to abrasive wear. Polyphenylene sulfide and polyether ether ketone have been the two primary high-performance resins used in thermoplastic liners, and each of them offers excellent performance in a wide variety of applications. However, the additional performance comes at a significantly higher cost than HDPE liners, powder coatings or rod guides. For this reason, many operators have avoided high-performance liners, especially as oil prices have fallen in the last couple of years.

A raised temperature polyolefin ketone (POK) is now being extruded into thermoplastic tubing liners to extend runlife in challenging environments at a much lower price than other high-performance resins. POK was originally commercialized by Shell Chemical as a replacement for HDPE in offshore applications where higher performance was needed. Shell discontinued production of the resin in 2000, and the technology was acquired by Hyosung shortly after. For the next decade, Hyosung worked to test the viability of POK as a high-performance resin. Within the last two years, Hyosung has developed a raised temperature strand of POK that is now being extruded into liner for the first time.

Production tubing is lined with polyolefin ketone thermoplastic liner. *(Photo courtesy of Lightning Rod & Pipe)*

Laboratory testing has shown that POK has a maximum continuous operating temperature of 240 F and a melting temperature of roughly 428 F. POK is resistant to salt solutions, hydrocarbons and most other chemicals present in oilfield applications. Multicomponent crude exposure testing was done over an eight-month time period over a temperature range from 68 F to 176 F. The modulus, yield stress and elongation properties were relatively unchanged after this test. Testing has also shown POK to be more resistant to abrasive wear and to have a lower coefficient of friction than HDPE.

Polyolefin ketone liners are currently installed in several high-failure wells in the Permian Basin. Field trials are in the preliminary stages, but early results are positive. Mean time between failures has already been extended on two separate installations, and there have been zero failures in trials to date. POK possesses many properties that potentially make it very well suited for use as pipe liner in corrosive environments. Pending successful field trials, the adoption of POK in deviated wellbores and corrosive environments would be expected. ■

that, it is roughly the drift of the tubing. When we pull that all the way to the surface it acts almost like a tubing scraper," he explained.

The next two pieces are the heaviest sections, which are the pump and motor with the wet connect system. When these two sections are pulled, there have already been two runs to the surface, so the inside diameter (ID) of the tubing is clean and clear, which makes retrieving and replacing the Access375 easier.

The company has introduced its Tiger Shark 2 pump, which has multiple enhancements in the bearing, bushing and standoff sleeve designs. *(Image courtesy of Summit ESP)*

Unconventionals boost ESP popularity

When unconventionals started coming around in the Bakken, Eagle Ford, Mississippi Lime and West Texas, ESPs suddenly became popular with many customers because the wells started flowing at 3,000 bbl/d and after a few months would draw down, Roberts said.

"We'd put in an ESP, and we'd be getting right back to 3,000 bbl/d. But what came along with that was high gas volumes, lots of abrasives and corrosives," he continued.

> "When we pull that all the way to the surface it acts almost like a tubing scraper."
>
> —*Greg Nutter, AccessESP*

Summit is an independent company that has stayed dedicated to research and development. It has its own slurry loop where it can test equipment in an abrasive environment. The company also has a dyno motor testing device and recently opened up a pressure vessel for cable and pump/motor component testing. The company can pressurize the vessel up to 6,000 psi to 8,000 psi and 650 F.

"We've been able to make advancements in cable-related technology. We are going to be coming out with a high-temperature pothead motor lead extension, which is the device you plug in from the cable to the motor," Roberts said.

With its work in unconventionals the company also has been able to make some multiple enhancements in the bearing, bushing and standoff sleeve design to its premium Tiger Shark pump. "We are coming out with a Tiger Shark 2. We've been able to increase our stage wear resistance in our pumps up to six times," he added. "What that has done is give us a three-fold increase in pump performance."

Summit has patents on its diffusers and impeller pump stages. In the stage diffuser, the company has a feature called an Erosion Buster, which is a small wedge-type device that with the normal wear of the abrasive redirects the wear from the outer diameter (OD) of the diffuser to more of the ID area.

The company found that without Erosion Buster in formations with a lot of sand, there was a lot of OD wear through the diffuser, which could wear through the pump housing, Roberts said. "We have been able to turn that around and deflect that wear pattern."

Summit has also developed a new variable speed drive, the Adaptive Control System 15 (ACS-15). "With the adaptive control is an in-house-made drive that has an option called harmonic cancellation. Many times a 6-, 12-, 18- and 24-pulse drive will send electrical harmonics back out on the grid, causing issues and disruptions in the electrical grid in the surrounding area. The option is similar to a noise cancellation feature in headphones," he explained.

"We can now get all the way down to less than 150 bbl/d pretty easily with some of those very broad extended range pump designs." ■

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Latest Technologies Form Future of Artificial Lift

Having the right technologies available enables operators to optimize well performance.

From sucker rod pumps, electric submersible pumps and gas lift to gas well deliquification technology, operators rely on innovative products and services to get them through point A to point B in an artificial lift operation. The well production life cycle depends tremendously on effective and reliable tools.

The following is a small sampling of the best available equipment, accessories and services that enable operators to maximize the value of their wells while also lowering costs.

Editor's note: The copy herein is contributed from service companies and does not reflect the opinions of Hart Energy.

Rigless ESP conveyance system for reduced deferred oil production

AccessESP integrated two practical technologies—a permanent magnetic motor and a side-pocket wet connect system—into one tubing-mounted permanent completion and slickline retrievable assembly. AccessESP's technology makes the retrieval and replacement of an electric submersible pump (ESP) system through tubing, using conventional slickline processes and equipment. No rig is required. This results in reduced deferred oil production, given the shorter planning and execution time with the slickline operation. AccessESP's equipment can be installed as a contingency for future ESP installations. The fullbore permanent completion can be deployed at the time of the initial completion. At any time in the future, an ESP can be installed using simple slickline operations. Typically the replacement can be completed in less than 72 hours. The technology provides fullbore access below the ESP system for easy remediation of the lower completion and reservoir, which maximizes the value of ESP wells with significantly lower intervention costs and minimal lost production. *accessesp.com*

The Access375 rigless ESP conveyance system was designed for challenging offshore and remote locations. *(Image courtesy of AccessESP)*

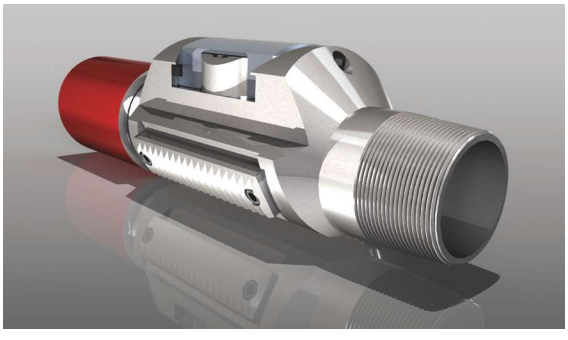
First rigless-deployed ESP system installed

Baker Hughes has installed the first TransCoil rigless-deployed electric submersible pumping (ESP) system, which is designed to help operators bring wells on production faster and lower the costs associated with installing and replacing ESPs. Because they can eliminate the need for a rig in fields where rig availability is a concern or where high intervention costs can limit artificial lift options, operators can minimize deferred production and lower their overall lifting costs to extend the economic life of their assets. The TransCoil system, developed in participation with Saudi Aramco, features an inverted ESP system with the motor connected directly to a new, proprietary power cable configuration, eliminating the traditional ESP power cable-to-motor connection. Unlike wireline-deployed ESPs, the fully retriev-

able TransCoil system does not have an in-well wet connection, which requires a rig to pull and replace if the wet connection fails. The TransCoil system was installed and commissioned in a well at 1,493.5 m (4,900 ft) in 7-in. tubing in Saudi Aramco's Khurais Field. The rigless operation reduced installation time nearly 50% over a rig-based installation, and further deployment efficiency improvements are expected in the future. *bakerhughes.com*

Hydraulic tubing anchor reduces rig time

Black Gold Pump & Supply Inc. has developed a hydraulic tubing anchor called R-Anchor. Tubing anchors are deployed for mitigating tubing movement in rod pump artificial lift. Tubing movement is caused by the required reciprocating motion of the downhole pump. At low to high strokes per minute, tubing wear can be moderate to catastrophic (e.g., a hole in the tubing). Traditional mechanical tubing anchors include many disadvantages: actuation requires rotation of tubing, large

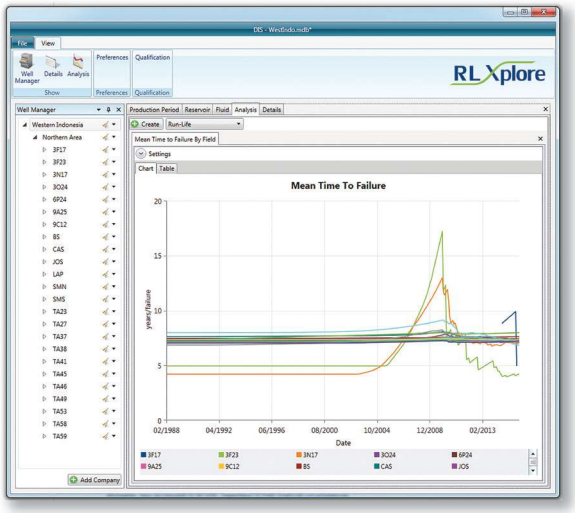


Black Gold's hydraulic tubing anchor, R-Anchor, contains large bypass areas preventing sand bridges and fluid slugs. *(Image courtesy of Black Gold Pump & Supply Inc.)*

outer diameter creates sand bridges and gas slugs, and they comprise numerous moving parts. These disadvantages are overcome by key features of the R-Anchor. The R-Anchor actuates by hydrostatic pressure between the casing and tubing, contains large bypass areas preventing sand bridges and fluid slugs, and incorporates a single moving part. Black Gold has run more than 5,000 R-Anchors with optimized gripping to the casing and heavily reduced rig time and cost on installation and extraction. *blackgoldpump.com*

Software tracks, analyzes equipment runlife data

Run-Life Xplore (RLX) is a software tool that enables companies to efficiently track and analyze artificial



Run-Life Xplore software can track data on more than 700 parameters for any asset. *(Image courtesy of C-FER Technologies)*

lift equipment runlife data, such as equipment component characteristics, downhole operating conditions and detailed failure information. By leveraging these data to identify key challenges and potential mitigating actions, operating companies can reduce equipment failure rates and increase well uptime. RLX contains a broad range of data qualification routines and industry standard statistical analysis tools that ensure that analysis results are accurate and useful. RLX was developed based on 15 years of data collection and analysis activities conducted by a group of operators in both the electric submersible pump and progressive cavity pump industries. *cfertech.com*

Software for real-time monitoring, decision-making, collaboration

Dover Artificial Lift's LOOKOUT monitoring and optimization system puts wellsite automation

A Dover Artificial Lift ESP installation takes place. *(Photo courtesy of Dover Artificial Lift)*

at a user's fingertips. Powered by Theta Oilfield Solutions' XSPOC software, LOOKOUT delivers a web-based tool for real-time monitoring, decision-making, collaboration and well performance optimization. From simple on/off notifications to active monitoring scenarios targeting key performance indicators, this monitoring and optimization system enables operators to stay connected to their wells. Fostering collaboration and streamlined workflows, this system allows easy access across a variety of platforms, from mobile to desktop. Leveraging the power of Theta's XSPOC artificial lift monitoring system, LOOKOUT can be used on every form of artificial lift including electric submersible pumps, rod lift, gas lift and more. *doverals.com*

Operate up to 32 wells on plunger lift with a single controller

During the recent boom in upstream development, many well sites were installed without consideration of artificial lift systems, specifically plunger lift. As wells have declined, plunger lift has become a viable option for production. However, the cost to retrofit these wells from an automation perspective can be expensive. However, the QLogiX controller is agnostic and communicates with and integrates with almost all other programmable logic controllers or remote terminal units on a typical well pad, including flow computers. Instead of investing in expensive add-on equipment, QLogiX can operate up to 32 wells on plunger lift with a single controller using wired or wireless instruments. This drastically reduces the investment required for optimizing older legacy wells or new wells in decline. QLogiX provides proven algorithms for use in liquid and gas well applications with the ability to store and access data retrievable by SCADA systems to allow remote optimization. *flow-data.com*

System prevents solids from entering the rod pump

The GARP system has several improvements that include a packer type gas separation pump design, which allows the reservoir fluids to enter the casing annulus above the pump intake. In addition, wells might be loaded and/or circulated down the casing and up the tubing to the surface, even for low-pressured reservoirs. A solids screen also can be incorporated with the ability to clean the screen *in situ*, and a solids separation and containment system has been improved. These improvements address the problems that plague rod pump systems. Those issues include poor pump performance due to gas interference. The system solves solids issues by preventing solids from entering the rod pump and also provides a trap to prevent solids from falling on top of and sticking the packer. The system also provides an *in situ* method without a workover rig to clean trash out of the pump, bring the solids to the surface and also allows loading the well to reduce the differential pressure sticking the pump in place. *garplift.com*

Improving artificial lift using multiphase pumps

A natural development for maturing wells is reduced inflow from surrounding formations leading to lower level in the production tubing, which in turn reduces uptime of pumpjacks and electric submersible pumps (ESPs). The low bottomhole pressure (BHP) will free up additional solution gas, resulting in an annulus gas cap. Traditionally gas is bled off and comingled with the liquid stream of the pumpjack; however, without pumping, the gas flow stalls and the well shuts in. The Multiphase Pump, designed for 100% gas to 100% liquid, is ideal for gas saturated with liquids. It is an alternative to a compressor, which relies on a combination of inlet scrubber and blow case that can sometimes lead to cycling and possible shutdowns from liquid slugs. In the Leistritz MAGU system (multiphase annulus gas unit) both the annulus gas and liquid streams are routed through the unit where the pump draws

The Leistritz MAGU system, shown in operation, keeps the annulus gas pressure down and maintains the tubing level. *(Photo courtesy of Leistritz Advanced Technologies Corp.)*

down the annulus gas pressure slightly above atmospheric pressure. This lowers BHP and will raise the tubing level allowing the pumpjack or ESP to operate safely with better inflow. With pump-off control, this results in uninterrupted production and less rod

wear. The MAGU also keeps the annulus gas pressure down and maintains the tubing level, even if the pumpjack or ESP is not running. *leistritzcorp.com*

Rod designed to reduce failure rates

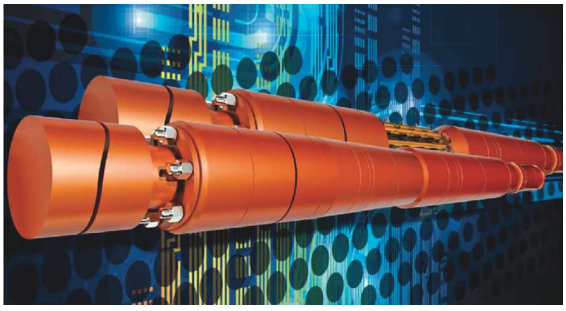
Lightning Rod and Pipe has released two distinct product lines with a focus on servicing deviated wellbores. The LightningRod continuous rod is manufactured to reduce failure rates by eliminating the most common failure point in a rodstring—the coupling. LightningRod reduces rod-on-tubing wear by distributing side loads along the entire length of the rodstring instead of being concentrated on the coupling. Separate alloys are available to meet the demands of mild to moderately corrosive well fluids. The rod is available in round and semi-elliptical geometries. Additionally, LightningFlo

A LightningRod continuous rod installation took place in the Permian Basin, allowing rapid workovers by eliminating the couplings in the rodstring. *(Photo courtesy of Lightning Rod and Pipe)*

thermoplastic liners are effective in protecting tubing from failures due to corrosion or abrasive wear. A range of polymers are available to meet the specific needs of a wellbore at an affordable price. The LightningFlo LF115 liner specifically has a continuous working temperature of 115.5 C (240 F), which allows it to withstand hot oiling temperatures without the cost of other high-performance liners. *lrpus.com*

PM motor offers versatility

Novomet offers an electric submersible pump (ESP) permanent magnet (PM) motor system. PM motors offer significant advantages over typical induction motors. Power and efficiencies are significantly higher in PM motors, with minimal degrading when



The length of a PM motor is generally 34% to 47% shorter when compared to a standard ESP motor. *(Image courtesy of Novomet)*

operating below the peak efficiency motor loading range. Less horsepower is required for a PM motor to do the same work as a typical induction motor ESP system. This efficiency equates to lower electrical consumption costs as well as lower equipment costs. The length of the PM motor is generally 34% to 47% shorter when compared to a standard ESP motor, which allows opportunities to operate in deviations that normal ESP systems cannot attain. The rpm range of a PM motor is far more versatile, as it can even operate in ranges as low as 100 rpm to 500 rpm, giving it the ability to operate a progressing cavity pump (PCP) system without the use of any gear reducer, which would be required in a typical electrical submersible PCP system. Finally, the PM motor can be manufactured in much smaller housing sizes, which allows entry into 4.5-in. casing that is equal or greater than 11.6-in. and 4-in. liners. Now a system is available for deployment inside of 2⅞-in. tubing. *novomet-usa.com/eng*

Rigless ESP replacement system also provides preventative maintenance

Electric submersible pumps (ESPs) often are selected as the optimal artificial lift method. However, when run on heavy-jointed tubing, an ESP requires frequent rig or hoist interventions to replace failed systems. These interventions lead to significant production deferment, increased costs and disruptions to operations. Furthermore, there are significant safety and environmental risks associated with heavy well interventions that can be duly addressed but never eliminated.

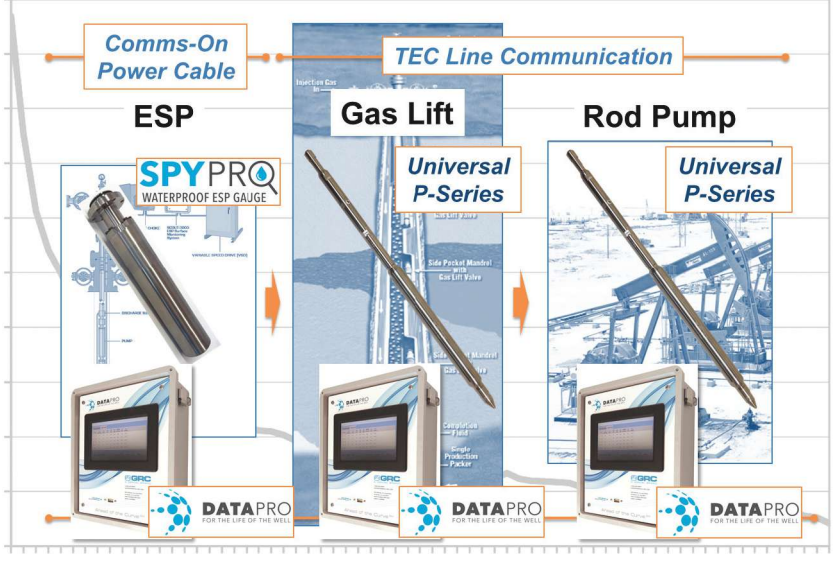
The Schlumberger ZEiTECS Shuttle rigless ESP replacement system features a downhole electrical wet-connector technology that enables standard ESPs to be shuttled through tubing on wireline, coiled tubing or sucker rods and plugged into a downhole docking station—all without a rig or hoist. Replacing

The ZEiTECS Shuttle system eliminates the need to mobilize a workover rig. *(Image courtesy of Schlumberger)*

ESPs without a rig minimizes production deferment, operating costs and HSE risks, and maximizes ESP runlife. The ZEiTECS Shuttle system also facilitates regular preventative maintenance and the exchanging of ESPs in response to changing well conditions instead of waiting for a failure. *slb.com*

Artificial lift tools optimize production

Sercel-GRC provides downhole instrumentation for artificial lift and reservoir monitoring markets worldwide. The company's artificial lift gauge systems provide subsurface data needed to optimize electric submersible pump, gas lift, progressing cavity pump, rod pump and jet pump applications. GRC's gauges have been installed in more than 37,000 artificial lift wells to measure pressure, temperature, vibration and other downhole conditions. GRC has released the industry's first universal artificial lift instrumentation system. Gauges can be installed through tubing, above a pump or below a pump. These installation options have been standardized, allowing one gauge to be redeployed through multiple artificial lift completion methods. GRC's new Data Pro surface data acquisition unit also has been designed to last the life of each well. The open-source Data Pro platform provides one common visualization and optimization option for all GRC universal gauges. *sercel-grc.com*



Sercel-GRC's downhole gauge systems have been designed for universal deployment and reuse through each well's artificial lift life cycle. *(Image courtesy of Sercel-GRC)*

New technologies coming in 2017

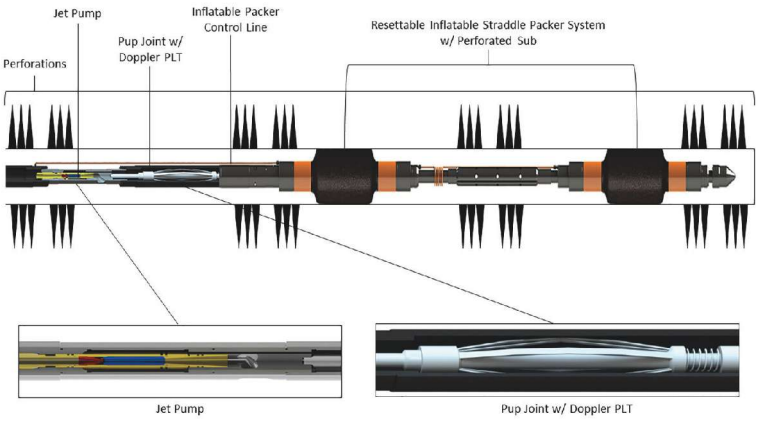
Summit ESP is the second-largest supplier in the U.S. for downhole electric submersible pumps. In December 2016, the company completed its 7,000th installation in Andrews County, Texas. The company remained fully invested in the 2015 to 2016 downturn and expanded its R&D capabilities.

A West Texas Summit ESP service technician reviews the setup for a variable speed drive for an electric submersible pump. *(Photo courtesy of Summit ESP)*

In mid-2017 Summit will release a range of new products. Just a few of the recently arriving new technologies include Summit's Adaptive Control System variable speed drive with harmonic cancellation capabilities, its durable patent-pending Tiger Shark 2 pump design, higher temperature pot heads and higher efficiency motors. *summitesp.com*

System measures fluid entry, phases of flow while in the hole

Production logs have been an industry standard for many years, but by themselves they are not a reliable way to evaluate the complicated flow regimes in modern multistage wells. Production logs work well at determining the phases of flow in horizontal or vertical wells, but determining from which stage or cluster the production is originating is more of a challenge. The Focused Production Measurement System from Tech-Flo measures fluid entry and the phases of flow while in the hole. It uses the flexibility of a hydraulic jet pump to produce and stabilize the well while each zone or stage is isolated between straddle packers. It is movable and resettable. The system increases and measures a flowing well's production, produces and measures a dead well's production and can produce a zone or stage's absolute openhole potential. It measures three-phase flow, temperature, static bottomhole pressure (BHP) and flowing BHP to determine a well's inflow performance. The system can be run in real time or memory mode. Conveyance methods include jointed pipe, coiled tubing or fiber coiled tubing. Suggested uses of this system include post-fracturing evaluation, prerefracturing evaluation and evaluation of vertical wells with stacked pay. *tech-flo.net* ■



The illustration shows the Focused Production Measurement System with packers straddling the zone of interest, a jet pump to pull production from the formation and a production logging tool to measure everything that passes by. *(Image courtesy of Tech-Flo)*

Solution to Sucker Rod Coupling Failures

Sucker rod coupling solves well failures resulting from production tubing and coupling wear.

By Diane Nielsen and William Nielsen
Materion Corp., USA

Nearly all of the wells operating in U.S. shale fields require artificial lift to produce oil and natural gas and nearly half of those wells experience failure as a result of tubing leaks. These failures are costly and hazardous events that operators have long been striving to avoid, with the cost of working over problematic wells running into many thousands of dollars per well per year.

The primary cause of tubing leaks is coupling-on-tubing wear in areas where couplings contact the inner tube wall, creating friction and damage. Sucker rod pumping in slightly deviated 3,048-m (10,000-ft) unconventional wells is uniquely challenging because of the sideloading of rods. Sucker rods can buckle due to forces acting in compression at the bottom of the rodstring on downstroke. This buckling in the rodstring in the deviated sections creates tubing and coupling contact that results in wear of either the coupling or tubing.

ToughMet couplings are part of Hess' standard production practice for its operating wells in the Bakken Shale. *(Image courtesy of Materion Corp.)*

The spray metal couplings commonly used downhole are made of a harder material than the steel L-80 tubing and, over a period of time, these couplings can wear the tubing down to the point of failure. The use of standard "T" couplings also can result in tubing wear because of galling. While rod guides often are deployed to stop sucker rods from bending and to enable them to maintain their centralized position in the production tubing, rod guides have a tendency to wear out rapidly and become ineffective.

Hess Corp. partnered with Materion Corp. to qualify and pilot the use of Materion's ToughMet 3 TS95 alloy for sucker rod couplings in deviated wells with higher than normal failure rates.

As a result of the successes observed in its field tests, Hess has installed the couplings in 265 of its Bakken wells and uses ToughMet couplings as part of its standard production practice, with installation being scheduled for all of its operating wells in the Bakken.

Search for a solution

In an effort to reduce well failures, Hess identified that the issue of tubing wear in unconventional wells could be addressed by using a more compatible coupling material. The Hess team turned to the ToughMet 3 TS95 alloy, a highly durable, non-galling, spinodal bronze made of copper, nickel and tin. The ToughMet alloy has a proven record in harsh, demanding environments. It is widely used for onshore and offshore drilling equipment components, bearings in aircraft landing gear, and industrial and mining equipment parts.

With its combination of high-strength and non-galling properties, Hess identified the alloy as capable of fulfilling the functional requirements needed for a sucker rod coupling application. With hardness that averages 20 on the Rockwell Hardness C scale (HRC) to 23 HRC, ToughMet is extremely compatible with L-80 tubing, which has a 23 HRC maximum.

Field testing

The two companies developed a prototype coupling for implementation in Hess' Bakken operations. Hess selected 10 problematic wells, installed ToughMet couplings in deviated sections during workovers and judged performance at six months, 17 months and 23 months.

Phase 1 of the pilot program began with Hess installing 1-in. slimhole couplings in 10 deviated wells that were experiencing deep-tubing leaks due to wear at a failure frequency rate of six to eight months. Hess installed ToughMet couplings in the bottom section of the 1-in. sucker rodstring located just above the pump.

Runtimes of the original 10 pilot wells have increased from six months to 12 months to 18 months to 30 months without experiencing a failure related to coupling or tubing damage due to wear, corrosion or fatigue in the sections where the ToughMet couplings were installed. In instances where the wells have failed and required workovers for other reasons, the ToughMet couplings showed little wear and have been reinstalled and are still in service.

In terms of operating costs, the couplings reduce workover expenses by more than $75,000 per well annually, with the net benefit of one year's uninterrupted production from a well producing 100 boe at $50/bbl, adding up to $150,000 in cash flow. Therefore the return on investment is substantial.

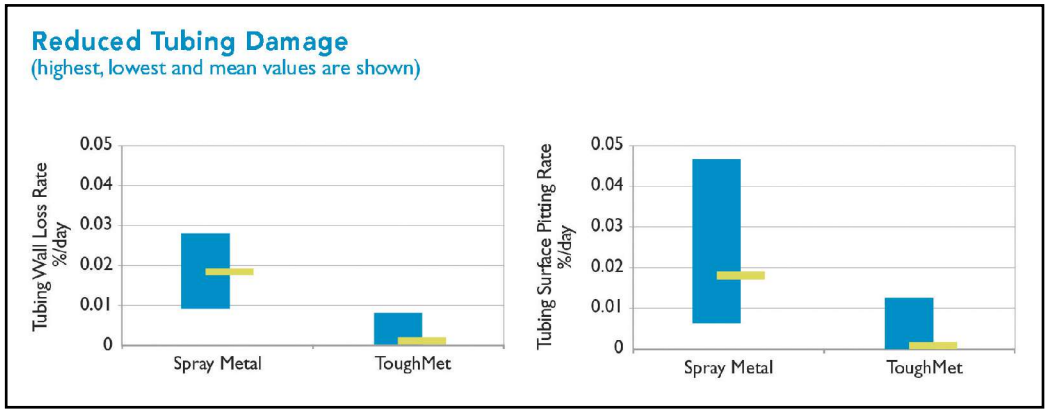
Due to such successful results in the field tests, Hess is installing ToughMet couplings in about 50 wells to 60 wells per month. Typical applications require no more than 40 ToughMet couplings per well.

Additional benefits initiate additional field tests

The company has installed ¾-in. full-size couplings and 1-in. slimhole couplings in the bottom 1,280 m (4,200 ft) of wells to reduce friction in the lower portion of the string.

Statistical analysis on output of the Hess test wells indicates there are additional benefits of using the new couplings, including increased fluid production, increased pump fillage, higher fluid loads and lower gearbox loads.

To gather more data to substantiate and quantify those results, Hess has plans to outfit an entire well with ToughMet couplings to reduce the overall friction on the system and the loads on the gearbox to determine the increase in pump stroke and productivity. Other operators will conduct field testing in 2017 as well.



Mean time to failure is increased when ToughMet couplings are used. *(Data courtesy of Materion Corp.)*

New applications

Based on the success of the sucker rod couplings, Hess and Materion are working to identify other areas in artificial lift systems where the ToughMet alloy would be of benefit. For example, the companies have designed a new ToughMet 3 TS95 Tapered Valve Rod Guide Bushing Coupling to act as a centralizer to prevent the valve rod bushing from wearing out the adjacent tubing, another common problem across the industry.

The coupling has a 2-in. outer diameter with ¾-in. rolled threads and tapered ends. It is installed on top of the valve rod bushing and is included by Hess on every Bakken well. The product is available commercially, with two additional operators currently field-testing it. ■

Taking Artificial Lift to the Next Level

Integrated platform increases ESP runlife by 181% in challenging Mississippi Lime Formation.

By Nick James, Ramana Palisetti and Remigio Stanislao Silva Sifontes
Schlumberger

Artificial lift has long proved to boost production in the vast majority of wells worldwide; however, pump systems must be carefully managed, especially in unconventional reservoirs characterized by rapid pressure changes and production declines. Traditionally, operators have focused on reacting to shutdowns and then studying trends to observe how pumps are behaving. Companies are now recognizing that the ability to use raw data to make real-time decisions and take immediate action is what makes the difference in maximizing production, minimizing downtime and reducing operating costs.

Operating data of electric submersible pumps (ESPs) are collected at the well site and transmitted for remote surveillance and monitoring. Several different systems are then used to analyze the data and ultimately determine the right course of action, a process that until now has been time-consuming and inefficient.

A new integrated, solutions-based web platform takes artificial lift surveillance and monitoring to the next level by providing analytic and diagnostic tools that enable operators to more proactively monitor and optimize pump performance, from a single well to an entire field. Using analytical tools embedded in the system, engineers can conduct well system diagnostics in real time and optimize data to understand the reasons behind every event to take corrective steps. In addition to monitoring the critical commissioning phase of an artificial lift system, the service provides long-term monitoring and analysis and proactively manages pump operation for the entire production life cycle of the well.

From a single platform, a dedicated and experienced team of surveillance engineers can monitor hundreds of data signatures that trigger alarms; analyze the data; identify likely causes of pump events, such as gas locking, production declines and solids production; and quickly adjust parameters to avoid shutdowns and return the pump system to normal operating conditions. Data are transferred via satellite or cellular connection from the well site, regardless of location, to a remote, 24/7 Artificial Lift Surveillance Center (ALSC). Centers are located in six strategic regions: North America, South America, Europe, the Middle East, Russia and Asia.

Officially released in March, the Lift IQ production life-cycle management service redefines the capabilities of artificial lift by extending pump life, reducing downtime and well interventions, minimizing deferred production, reducing capex and opex and maximizing production efficiency. The service has been deployed in more than 30 countries to more than 200 companies (Figure 1).

Operators can customize the type of life-cycle management service by choosing from four convenient service levels, all with ALSC access. The first level includes visualization and system protection, the second tier provides proactive ESP management, and the third and fourth levels identify potential wells and fields for production optimization.

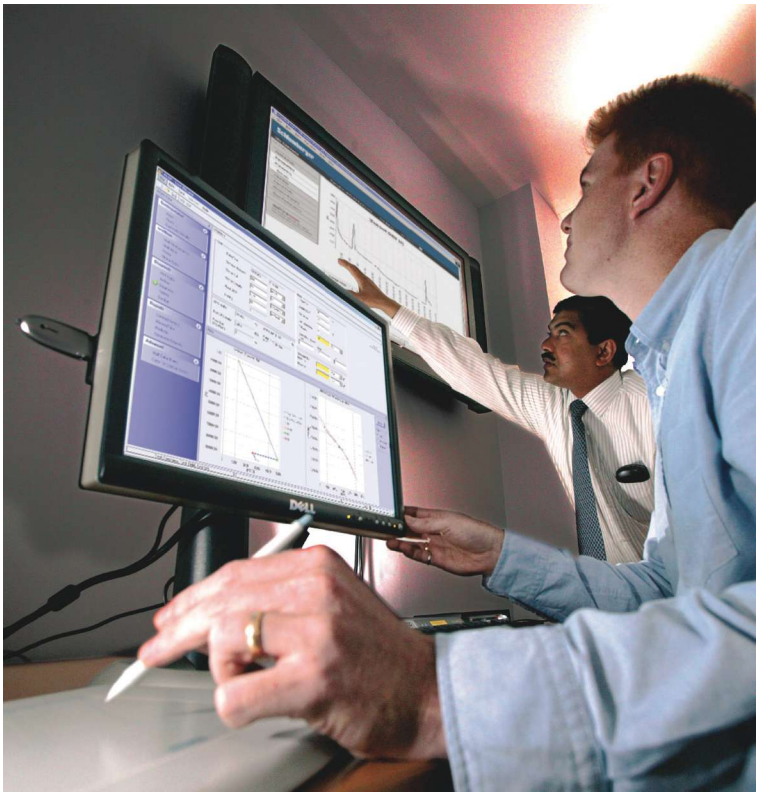
ESP optimization in the Mississippi Lime

An operator in North America selected service level two—remote ESP surveillance, diagnostics and proactive management—to address rapid produc-

tion declines, solids production and high gas volume fraction in the unconventional, liquids-rich Mississippi Lime Formation near the Oklahoma-Kansas border. The operator needed to maintain ESP uptime to increase production while keeping lifting costs low in four wells with declining multiphase production, high gas-to-liquids ratios (GLRs) and a high degree of produced solids, primarily from sand used in hydraulic fracturing. The key challenge was managing oil production that ranged from initial rates of 4,000 bbl/d down to 400 bbl/d or less after a year of operation and increasing GLRs, from 300 scf/bbl to 1,700 scf/bbl.

Schlumberger designed a strategy that included abrasion-resistant ESPs to minimize risk of failure from solids, with compression pumps to provide enough flexibility to perform over a wide range of production volumes. The pumps needed to be properly sized to lift the initial high liquid volumes, then adjusted when production declined. A multiphase gas-handling system was incorporated to manage GLR variations, while a high-temperature ESP sensor monitored the operating conditions. The sensors provided real-time monitoring of intake pressure and temperature, motor temperature, vibration, current leakage and pump discharge pressure—all crucial for diagnosing pump problems and improving performance in unconventional wells.

To optimize the workflow, the Lift IQ service used the sensor data to diagnose adverse events in real time and recommended within minutes corrective actions. In Well A, the ESP system and production life-cycle management service managed a 94% production decline, from 5,424 bbl/d to 300 bbl/d over 393 days, with 84% uptime. GLR increases from 350 scf/bbl to 1,200 scf/bbl also were managed. The service also helped to overcome communication problems resulting from an ESP in one well tripping the ESP in an adjacent well.



Engineers monitor alarms and analyze data transmitted from multiple wells across fields simultaneously in real time, up to 24/7/365 at a Schlumberger Artificial Lift Surveillance Center. *(Photo courtesy of Schlumberger)*

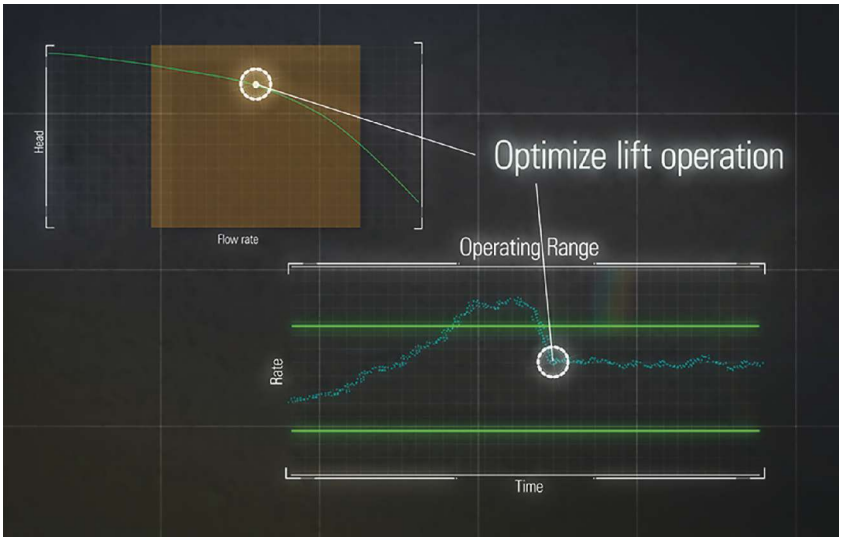


FIGURE 1. Optimizing wells through monitoring and surveillance is proven to minimize downtime, maximize production and reduce total operating cost. *(Image courtesy of Schlumberger)*

In Well B, one ESP managed a 90% production decline and a GLR increase from 320 scf/bbl to 1,300 scf/bbl over 189 days. To manage drawdown, the ESP modified pump intake from 1,000 psi to 600 psi. A second ESP managed the lower production of 200 bbl/d of fluids and 250 Mscf/d of gas for 262 days.

Increasing runlife

In Well C, the ESP system performed for 654 days through a fluid production decline from 4,275 bbl/d to 750 bbl/d over five months, and a slower drop to 350 bbl/d, with a GLR of 1,200 scf/bbl. Cumulative pump uptime was 68.2%, with most of the downtime related to manual shutdowns, ESP trips during low- or no-flow periods and power-generation issues. The production life-cycle management service analyzed pump alarms in real time to optimize ESP performance as downhole conditions changed, and guided decision-making when communication from a nearby well destabilized the pumps. At the end of the ESP life, this well had 16% more cumulative liquid production than a comparable offset well produced with just 53 days on an ESP followed by gas lift, and 55% more cumulative liquid production than was planned for gas lift alone.

In Well D, one ESP managed production decline of 84% and GLR increase of 182%, drawing down the well from 1,300 psi to 400 psi over 190 days. A second ESP managed the next 221 days of production, which declined by 86%.

All monitoring, analysis, diagnostics and communication to the field were managed in real time from the ALSC in Houston. On average in the Mississippi Lime Formation, ESPs operated with the production life-cycle management service increased average runlife by 181%, from 118 to 322 days, and managed GLR increases up to 243% and production declines up to 94%.

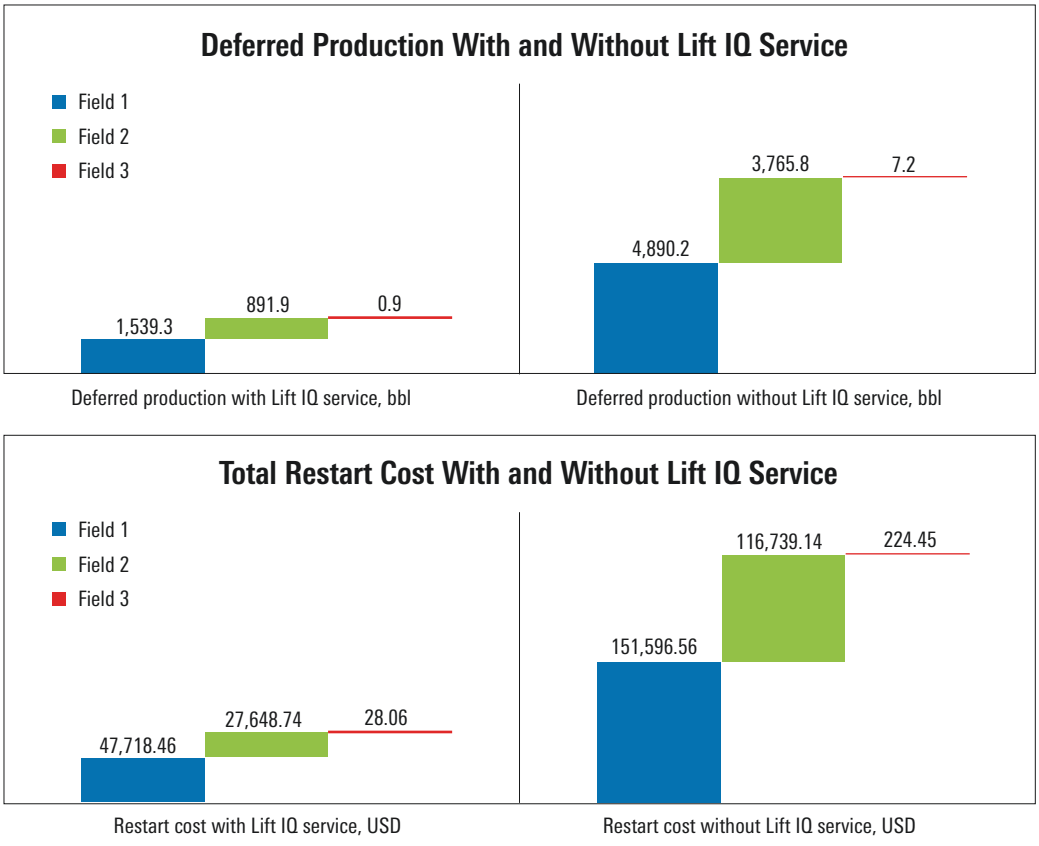


FIGURE 2. Using the Lift IQ service to monitor well performance and confirm well restarting reduced deferred production and overall costs. *(Data courtesy of Schlumberger)*

The Lift IQ service also has been implemented in fields outside North America. In Ecuador the service enabled the successful restart of 42 wells after an unexpected power outage impacted the ESP systems. In addition to deferring production, the power interruption had the potential of causing HSE and security issues. From the ALSC in Bogota, Colombia, engineers monitoring the operation prior to the power interruption were able to remotely restart the ESPs, confirm that the wells were back online and monitor performance during the stabilization period.

The 42 wells were restarted in a record time of 2.8 hours—four minutes per well—instead of the 16.8 hours anticipated without remote intervention. Deferred production was reduced by an estimated 72%, representing a cost savings of $190,000 (Figure 2).

The integration of monitoring and surveillance with real-time analytics and optimization in a single platform with 24/7 remote access has expanded the envelope for artificial lift management far beyond conventional limitations. By applying science to the data to make informed decisions, operators can focus on the entire production life cycle of a well or field, expanding the possibilities to maximize production while reducing cost and downtime. ■

Reducing Costs and Increasing Production

A look at the technologies behind the development of a wear-resistant and wide-range system for use in artificial lift applications.

By Lorne Simmons
Borets

With the ultimate goal of reducing production costs while increasing well productivity, Borets has worked to increase the number of products that utilize its permanent magnet downhole motors (PMM). PMMs typically range from 93% to 95% efficient with a power factor greater than .96 while its counterpart, the traditional induction motor (IM), offers lower efficiency and a lower power factor.

Tests of PMM electric submersible pump (ESP) solutions repeatedly show a 10% to 20% direct cost savings on the operating electric bill, equating to tens of thousands of dollars a year in opex with near-unity power factor. By using a permanent magnetic generated field instead of inducing a temporary field by means of a current, the motor experiences fewer electrical losses and is driven more economically. Consequently, it delivers longer runlife and significant power savings.

VSD solution

Borets has developed a new range of ESP technologies centered on driving artificial lift from downhole rather than from the surface. This approach enables the pumps to be pushed into the curve or lateral sections of the well without wearing out tubing or rods by rotating them through a crooked hole. In October 2015, the company released its AXIOM II variable speed drive (VSD), a universal VSD ideally suited for operating ESP induction motors, PMMs and high-speed PMMs. The AXIOM II offers unique functionality, providing operators with the flexibility to use PMMs with a state-of-the-art VSD solution to optimize production, while not creating inventory or training issues with existing induction motor inventory.

Wide-range, wear-resistant option

Last year, the first version of its high-speed wear-resistant/wide-range (WR2) system was introduced, which includes a packet designed pump, a PMM and sensor. The initial North American installation was completed on May 15, 2015, in a northwest Oklahoma well designed to test the pump's ability to handle a wide range of flow, gas slugs and flowback of frack sand over an extended period.

The engineered system delivers a cost-effective artificial lift solution aiming to overcome the challenges associated with frack sand flowback, gassy production and rapid decline rates as commonly experienced in unconventional well production.

The WR2 pump design initially targeted flow rates ranging 1,900 bbl/d to 560 bbl/d and 1000 bbl/d to 250 bbl/d. In order to cope with the high degree of produced sand in unconventional wells, the WR2 is constructed using metal injection rather than foundry casting, resulting in significantly improved abrasion resistance and longer system run life.

The WR2 system efficiency is further enhanced through the inclusion of proven PMM technology. Using a PMM, ESP system power consumption is reduced by far greater than 10% under loaded conditions that routinely occur during gas slugging events. Additionally, by using a PMM the ESP is able

Tests of PMM electric submersible pump (ESP) solutions repeatedly show a 10% to 20% direct cost savings on the operating electric bill...

to be of a shorter construction. This saves money on motor construction and enables the ESP to better navigate through deviations.

The system also includes an AXIOM II VSD, allowing users to have a single VSD capable of running both PMM and induction motors from the same drive and common interface.

Current results

As of early 2017, Borets has installed nearly two dozen WR2 systems in U.S. land operations. One WR2 system was pulled after five months of operation when production declined from more than 1,500 bbl/d to less than 300 bbl/d due to scaling. In the course of trying to maintain production rates, the WR2 system maintained production between 300 bbl/d and 350 bbl/d while operating at higher speed (80 Hz to 90 Hz) than would be available with a conventional IM ESP system. After pulling the WR2 system, detailed inspection and analysis of the pump equipment showed erosional wear on the stages to be less than 20 cm (7.9 in.), a remarkable improvement over conventional ESP pump stages used on wells in the same area. The WR2 system demonstrated suitability for harsh well conditions and the ability to handle a wide range of production abrasives and gas with the goal of extending run life and minimizing well interventions.

A WR2 Pump Stage after five months of operation in a Permian Basin well shows very little wear from abrasion. *(Photo courtesy of Borets)*

Future developments

Borets is expanding the range of WR2 systems, introducing an additional pump size and increased gas-handing capability across the full range of WR system capability. Further augmenting the wide range of WR2 system capability will be the introduction of a 4,500 bbl/d to 1,000 bbl/d WR2 pump. Additionally, gas separators for all three WR2 pump sizes will be introduced, enhancing free gas capacity upward of 80%. A pump such as this that can produce through the frack cleanup and through what would normally be several pump changes during the initial decline stands to greatly enhance customers' return on investment by lowering costs and optimizing the oil produced during this critical period.

Borets has further expanded its PMM capability by adding three additional motor sizes and a significantly higher horsepower range. Available now are 4.06-in.-diameter high-speed PMMs up to 242 hp, 4.06-in. regular speed PMMs up to 228 hp, 4.56-in. high-speed PMMs up to 241 hp and 4.56-in. regular-speed PMMs up to 400 hp. Additionally, PMMs are now available in 512 series and 562 series (up to 760 hp and 1,000 hp, respectively).

SAGD solution

The company continues to build on a steam-assisted gravity drainage (SAGD) ESP solution introduced in 2016. Designed specifically for viscous applications requiring SAGD and other thermal recovery technology methods, the Borets SAGD ESP system features thermally compensated compression pumps and gas-handling devices with abrasion-resistant redesigned bearings, as well as high-temperature materials rated up to 250 C (482 F) to ensure extended ESP runlife in even the harshest environments.

This design includes an innovative new seal design with improved thrust bearing design, expansion chambers and plugs. New pot head designs have also been developed to eliminate this common mode of failure. The SAGD solution has been designed to improve the mean time between failures of the ESP system in these challenging applications. ■

Sucker rod couplings made of an advanced alloy called ToughMet are putting the traditional challenges of couplings to rest. This nonmagnetic copper-nickel-tin alloy provides high strength and outstanding galling and corrosion resistance. In field tests, ToughMet 3 Sucker Rod Couplings tripled average run times and increased fluid production.

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