Companies Search for Efficient, Economic Artificial Lift Solutions

By taking an integrated approach to artificial lift R&D in unconventional wells, companies can compare the estimated lift of the well and the total cost of ownership.

By Mary Hogan
Associate Managing Editor

With the oil and gas industry's focus shifting from development of new, costly sites to coaxing more resources from established plays that are more economical, artificial lift will play an increasingly important role in the E&P sector.

As companies seek to manage expenses, they also have an eye to the future in ensuring supply of oil and gas, which remain necessities to powering today's society. "R&D is really what will enable us to address the challenges the industry faces," said Spyro Kotsonis, engineering manager, artificial lift for Schlumberger. "The most basic targets of lifting cost per barrel and uptime never really go away. They remain the long-term challenges that we continue working toward."

Thanks to artificial lift R&D efforts, producers can extract increased resources from the ground while operating in ever-deeper, higher-temperature environments. Research in the field also enables greater production flexibility, improved reliability and the capability of better handling changing multiphase fluid states, according to Tariq Ahmed, Cameron's product manager for artificial lift systems.

The CAMLIFT linear lifting system mounts directly onto the wellhead. *(Photo courtesy of Cameron)*

"New wells are starting out with higher flow rates and are then rapidly declining," Ahmed said. "If the outcome of R&D work is to create a pumping system that can serve the well for an extended period of time and thus spend less capex, then this represents a significant achievement."

The success of the petroleum industry has gone hand in hand with R&D efforts since the drilling of the first commercial oil well, the Drake in Titusville, Pa., in 1859. "Operators continually search for new methods to maximize the value from their assets, and technology is the vehicle that delivers this value," said Peter Lawson, director of technology for Baker Hughes.

Advances in R&D efforts have led to the development of artificial lift systems that can operate in highly deviated wellbore sections, extremely high bottomhole temperatures, wells as deep as 30,000 ft, water depths to 10,000 ft, heavy oil operations and fluid streams with high levels of natural gas and/or solids in the fluid, according to Lawson. "As oil and gas plays become more challenging, there is greater demand for research and development aimed at minimizing operators' opex while maximizing production from their assets," he added.

At the Artificial Lift Technology and Research Center in Claremore, Okla., engineers test alternative intervention methods, conduct system integration testing and work to increase ESP system reliability in harsh environments. *(Photo courtesy of Baker Hughes)*

Unique challenges in unconventional wells

Of onshore oil wells, almost 90% need some sort of artificial lift, according to the Tulsa University Artificial Lift Projects (TUALP).

Unconventional shale plays present many unique challenges, including extraordinary depth and length of lateral sections, highly transient multiphase flow behavior and rapid production decline rates during the first year or two of production, according to Bill Lane, vice president of emerging technologies for artificial lift systems at Weatherford. "Shale wells require lift technologies that can handle gas slugs and particulate matter while operating efficiently over a wide range of production rates," he said.

Reliability and value remain key challenges for most producers. "Reliability impacts both production revenue and operating costs," Lane said. "Value does not always imply a lower cost." He noted the company's new tubing anchor, which can accommodate capillary tubing to inject precision-metered chemicals below the tubing anchor. "This simple device has saved one producer $15 million per year in a field of 200 wells by eliminating scale and corrosion-related pump failures while reducing chemical treatment costs," he added.

With many wells producing for 15, 20 or 30 years, ensuring the reliability of artificial lift systems can remove limitations on production. "Even though no single artificial lift system is appropriate for the whole life of a well, we want to make sure that the limitation is not due to the equipment anymore," said Kotsonis of Schlumberger. "It's no longer [because of] our systems, but rather just [due to] the natural production change of the reservoir. That level of reliability, when combined with the ability to switch out equipment quickly while using the appropriate technology adds value to our customers' top line throughout the market."

Unconventional wells often require increased system flexibility. The reservoir pressure in unconventional wells often is created by artificial means, with fluid produced quickly. Over the course of a year, though, production declines rapidly in these wells, according to Ahmed of Cameron. "The initial pumping system may not be flexible enough to efficiently handle a flow range from 2,000 bbl/d to as little as 50 bbl/d," he said. "The operator is investing capex at the front end, and then somewhere along the way the well dictates the need to switch to another form of artificial lift, and even a third form may be required."

Improving well economics

Economics play a key factor in the decision to change out artificial lift systems over time. The focus has moved away from keeping costs of individual bits of technology low to lowering the overall lifting cost and using the right lifting method at different times during the life of the well. In this way, operators are able to extend the economic life of an asset while ensuring optimum lift, according to Kotsonis of Schlumberger. "Wells are drilled in campaigns of up to a few years, but they're produced over decades," he said. "Artificial lift has a lot more leverage on the increase in recoverable reserves and really affects these reserves more than the first few years of an asset's life."

When selecting the appropriate artificial lift system for a specific well, economics is the main driver, according to Monday Okoro, president of artificial lift for Schlumberger. "You want to apply a specific technology that makes economic sense for the customer," he said. "You don't apply technology [just for] the sake of technology. So the economics is really a significant driver, and it's all about total cost of ownership for the life of the well."

Operators also must take into consideration production of horizontal laterals when deciding between various artificial lift systems. "Most of the technology around artificial lift is still being tweaked to fit horizontal applications; it's being adapted from vertical wells to horizontal well applications," said Ahmed of Cameron.

Well construction considerations

The industry is finding itself without any generally accepted methods for producing the horizontal section. As such, operators are getting into the heel of the well but not the toe, with undulations in the horizontal section presenting a further complication. "Dewatering the undulations is an issue," Ahmed noted. "For example, decisions need to be made about whether multiple pumps are needed in one well to drain across the long horizontal section."

The method that Cameron uses to get deep into the heel of a horizontal well involves a system that has the ability to run very slowly, reducing wear on the rodstring, tubing and pump. "This allows for operation over a longer period in a deviated section," Ahmed explained. Tight space poses an additional challenge to producing horizontal sections, with pumping systems usually needing to be run through 4½-in. liners, he said.

Decisions made during the well construction phase can have major impacts on production options later on. "Often, artificial lift technology is not taken into account, resulting in wellbore deviations or casing sizes that are not ideal to achieve the production expectation," said Lawson of Baker Hughes.

The greater the deviation or the smaller the casing, the more restrictions that are placed on the size of the artificial lift system, impacting flow rate and ultimate recovery or the type of artificial lift system deployed. "To overcome these challenges requires more robust artificial lift systems that can be placed deeper, run through greater buildup rates or in small casing sizes to maximize overall recovery," Lawson said. Engineers at the Baker Hughes Artificial Lift Research and Technology Center in Claremore, Okla., recently designed an electric

The CAMLIFT linear lifting system is particularly suited to pad well sites, where space restrictions are common. *(Photo courtesy of Cameron)*

Novomet developed a device allowing an ESP to operate in a dogleg severity of up to 4 degrees per 100 ft. *(Image courtesy of Novomet)*

submersible pump (ESP) system capable of passing through buildup rates up to 25 degrees per 100 ft.

Wells in very deep shale plays like the Bakken, Eagle Ford and Mississippi Lime have typically required heavy wall casing, which translated to a very small diameter, according to Maxim Perelman, CEO for Novomet. "The traditional ESP outside diameters are larger than the casing diameters that are being installed today," he said. To overcome this challenge and allow ESPs to be placed in slim wells, Novomet designed pumps with an outside diameter as small as 2.17-in. that can fit inside 2⅞-in. tubing.

Technicians monitor live data from one of the seven downhole test wells at the Artificial Lift Technology and Research Center. *(Photo courtesy of Baker Hughes)*

An additional concern involves the inability of ESPs to be installed in areas with a dogleg severity of greater than 1 degree per 100 ft. "When an operator drills wells today, they have to drill in 200-ft sections at less than 1 degree per 100 ft, which is very difficult to do," Perelman said. "But they do that in order to install whatever their artificial lift system is." The company recently developed a device that will allow an ESP to operate in a dogleg severity of up to 4 degrees per 100 ft.

Combating high gas levels and slugs

High levels of gas entrained in the production fluid pose another major challenge to operators, according to Lawson of Baker Hughes. The gas must be produced through the pump, separated and vented to the well annulus, compressed back into the production fluid or prevented from entering the fluid column.

"The presence of gas reduces the pumping efficiency of ESP systems and impacts the bottom line for operators," he explained. "Gas accumulation prevents fluid progression through the pump, which creates gas locking and causes the system to shut down or potentially become damaged due to overheating."

In unconventional wells with long horizontal laterals, low-pressure areas in the lateral can cause gas to accumulate, creating gas slugs. These slugs prevent fluid from progressing up the pumping system.

"New innovations in variable-speed drive software technology can automatically identify a gas slug and adjust the ESP speed to clear the slug. Then, the software resets the ESP system operation to once again begin pumping," Lawson said.

Gas separator technology uses centrifugal force to force gas along a specific path, venting to the well annulus to prevent it from entering the pump. Charge pump and gas-handling pump stage technology compresses and homogenizes the free gas back into the fluid, allowing for improved pumping. Gas-avoiding pump intakes are specially designed for ESP systems placed in horizontal orientations to prevent gas from entering the pump intake, according to Lawson.

One of TUALP's current research projects examines artificial lift conditioning for deviated and horizontal wells. The study identifies slugging as a major challenge to the performance of different pumps such as ESP and rod pumps and finds that the problem becomes greater in highly deviated and horizontal wells. As part of its research, TUALP is analyzing slugging behavior for a greater understanding of the liquid loading challenges, while looking at strategies for mitigating slugging and gas-liquid separation.

Turning to multiphase computational fluid dynamics (CFD) developed for its nuclear and turbine businesses, GE Oil & Gas has been able to better model hydraulic performance of its pumps. "This is being used to increase the performance range of our systems as well as the amount of gas that can be handled," said Jerome Luciat-Labry, president of Well Performance Services. The company also looked to its turbine business for a wear coating that can be used with gas separators and pumps and that allows 14 times more durability. GE also pulled in rotordynamics expertise from across the company to incorporate architectures into its bearing designs that can increase stability and reduce the chance of rotordynamic problems.

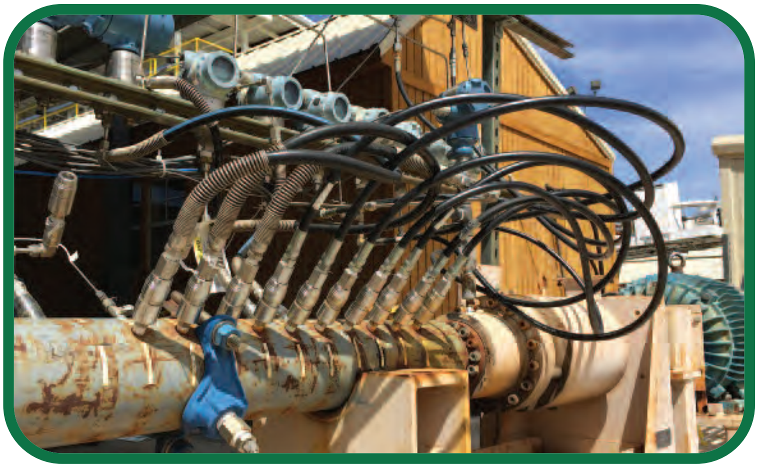
Fluid flow challenges

Pumping systems also need to be capable of dealing with multiphase fluids and potential solids, according to Ahmed. "Many things can go wrong downhole—pumps can get sanded in, making them difficult to retrieve. This can result in potential damage to the wellbore," he said. "There is much to be understood, learned and improved upon in this area."

Multiphase flow technology must be able to handle the changing gas, fluid and solid phases that are being produced. "The fast decline curve of unconventional wells causes the phase behavior to change drastically in short periods of time," he said.

Much progress has been made in modeling both steady state and transient multiphase flow behavior in wells and pipelines, according to Hong-Quan Zhang, Ph.D, director of TUALP and an associate professor at the University of Tulsa's McDougall School of Petroleum Engineering. "The inlet flow condition has significant effect on the performance of an artificial lift apparatus," he explained. "Artificial lift performance under transient multiphase flow conditions also needs to be studied."

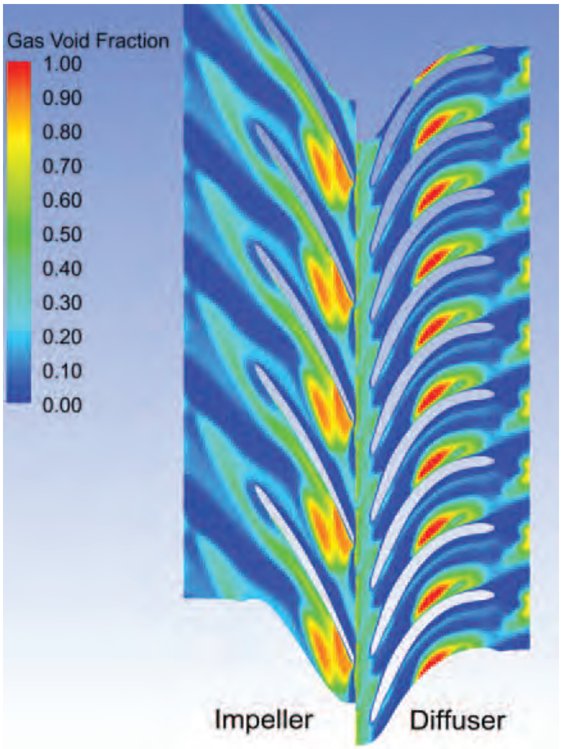
The R&D community increasingly looks to CFD simulation as a powerful tool to understand the single-phase and multiphase flow through an arti-



One of the TUALP facilities for testing ESP performance under gassy conditions with stage-by-stage boosting pressure measurements is shown. *(Photo courtesy of TUALP)*

An ESP is installed on an operator's site in southern Oklahoma. *(Photo courtesy of GE Oil & Gas)* ficial lift system, he added. "It should be applied more routinely in artificial lift R&D, in addition to experimental measurements and observations."

One of TUALP's most recent CFD simulations looks at ESP sand erosion, which impacts the reliability and life expectancy of ESPs. The study will observe erosion rates under different flow conditions using sand of varying size, property and concentration to identify areas in an ESP that are vulnerable to sand erosion.



CFD simulations show areas of gas accumulation at the backs of the impellers of an ESP when its performance deteriorates. *(Image courtesy of TUALP)*

Looking at the system as a whole

When looking at artificial lift challenges, an integrated approach is necessary. "We really need to look at applying the technology to address both the life of the well and the total cost of ownership," said Kotsonis of Schlumberger. "You can only do that if you're looking at the complete system as opposed to everyone continuing to piecemeal separate elements together."

Taking an integrated approach involves focusing on the availability of power supply necessary for operators to be able to take advantage of artificial lift technologies. "The biggest outlay our customers usually have up front is building the infrastructure to bring power," Kotsonis said. "Once power is available around the reservoir or a field, then [operators] have access to a lot more technologies."

Weatherford has identified advancement of separation technologies for horizontal sections of wells as an immediate challenge. Another challenge is looking at lower cost distributed sensing technologies such as fiber optics that can help optimize production system performance. Downhole power generation for sensing and communication to the surface is a future enabling technology, which could open the door for broader use of subsurface measurement and lift system control.

"Taking that a step further, subsurface power generation sufficient to power-lift systems is not out of the realm of possibilities, although that is not on the immediate horizon," Weatherford's Lane said. "Other challenges will include reliability of subsea systems and lift systems in multiple legs of multilateral completions."

Looking at the system as a whole also should include having an alternate deployment method for rapidly switching out artificial lift systems as the needs of a reservoir change over time. Once equipment needs to be changed, if there is a better technology available to be used but the cost of such a technology is prohibitive, the industry finds itself having to "seek out as much as it can from whatever it happens to have working at that moment," Kotsonis said, adding, "Yet, if we have an alternate deployment method that allows us to lower the cost of intervention, we're able to radically decrease the cost of the deferred production."

System improvements that reduce the cost of equipment transport, infrastructure, installation and associated downtime along with things like tubing change-outs and availability of equipment can greatly benefit well economics when looking at the whole system. "Producers' goals are to minimize capex and opex while reliably making their production targets," Ahmed said. "Those targets are highly affected by downtime."

A 10% or 30% increase in system reliability can significantly reduce downtime, which can yield significant economic improvement. Decreasing energy consumption or moving from electric motors to permanent magnet motors can make incremental improvements that quickly add up, he said.

Greater reliability can maximize uptime and thus increase production, which directly impacts the profitability of a given well, according to Okoro of Schlumberger. Operators should begin by looking at the percentage of time that is spent pumping oil, whether on a daily, weekly or monthly basis. "Maximizing uptime begins with taking an integrated approach from an engineering and optimization standpoint to ensure that the equipment you're going to put in the well will be in harmony with the reservoir conditions, such that you can maximize the uptime and you don't have too many starts and stops with the equipment," he said.

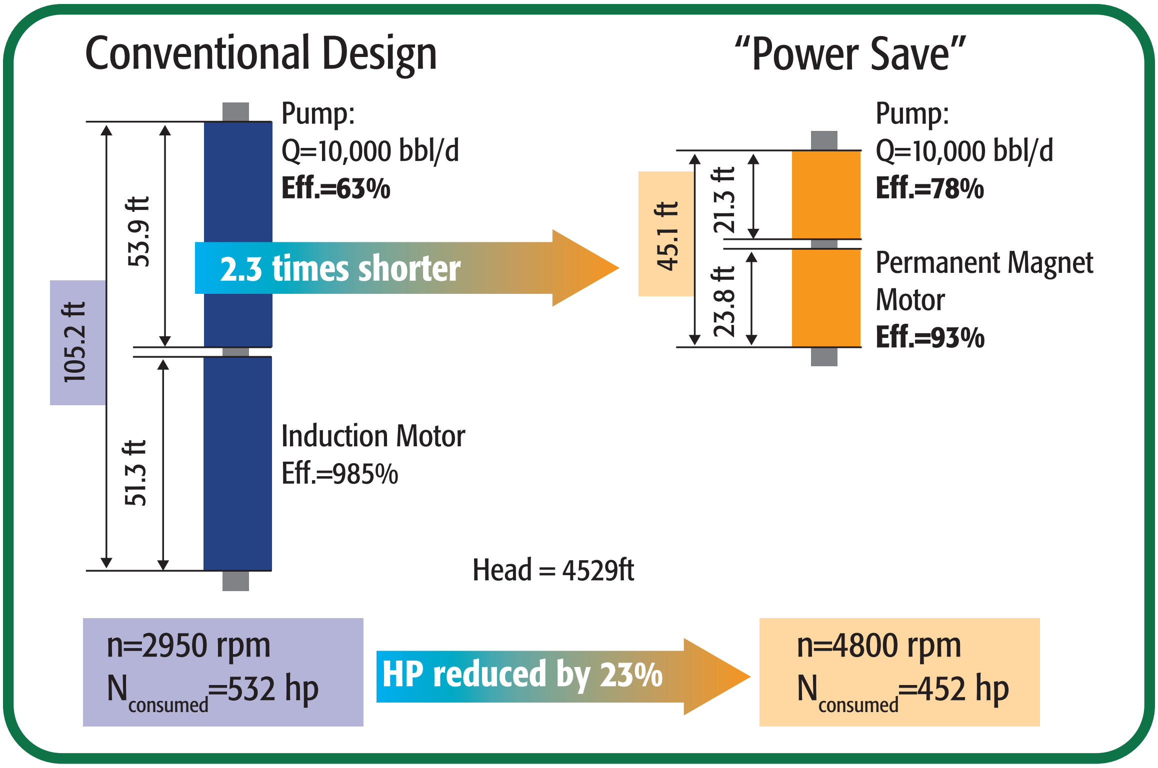
R&D centers and collaborative efforts

When it comes to R&D efforts, several companies and organizations have dedicated specific centers to finding solutions to artificial lift challenges. GE Oil & Gas will open its ninth Global Research Center in Oklahoma that is exclusively dedicated to oil and gas technologies in summer 2016, allowing the company to accelerate the development and testing of products in the field to enhance the performance and economics of unconventional oil and gas projects.

"Production optimization—reducing opex and driving EURs—will be a priority," said Mike Ming, general manager of the Oil & Gas Technology Center. "It's essential for delivering the cost improvements and production efficiency customers need today."

Using equipment and test wells for laboratory testing prior to field projects, the 120,000-sq-ft

In summer 2016, GE Oil & Gas will open its ninth Global Research Center in Oklahoma, which will focus exclusively on oil and gas technologies. *(Image courtesy of GE Oil & Gas)*



Novomet's Power Save ESP system reduces power consumption by 25% by combining a centrifugal pump with a permanent magnet motor. *(Image courtesy of Novomet)* center will work to develop next-generation artificial lift systems used for reducing costs and increasing the flow of liquids from production wells. "We'll be working to develop full well life-cycle management systems, artificial lift systems for unconventionals that improve gas handling and incorporate advanced materials to withstand harsher conditions, and solutions for lower-volume producing wells," Ming said.

GE and Devon recently announced a technology partnership that is focused on artificial lift, advanced drilling technologies and water treatment innovations, which is being led through the center. In addition, GE's focus for its Well Performance Services business remains on developing hybrid systems, unique completions and advanced mechanical designs. "These mechanical designs leverage computational fluid dynamics and aerodynamic/rotordynamic expertise from GE engines and are included in our artificial lift gas-handling pumps," Ming explained.

Novomet's research facility includes 13 test wells capable of simulating any well condition found in the world, according to Perelman. The facility also includes 20 test benches capable of testing specific components of an ESP in high-sand, high-gas and high-temperature environments. "When a client says he's got a problem, we're able to simulate that problem, create the solution and manufacture the solution in a relatively short period of time," Perelman said.

As part of its R&D efforts, the company was able to reduce power consumption by 25% by combining a centrifugal pump with a permanent magnet motor in its Power Save ESP system. "With the price of oil falling, this is good news," he added.

In February 2014, Baker Hughes opened its $60 million Artificial Lift Research and Technology Center in Claremore, Okla. Engineers at the center work to reduce opex by testing alternative intervention methods, conducting system integration testing and increasing ESP system reliability in harsh environments, according to the company's website.

Weatherford has partnered with Tulsa University's Horizontal Well Artificial Lift Project (TUHWALP) to study the issues related to artificial lift in horizontal wells. Weatherford also collaborates with companies in other industries, outside laboratories, testing organizations and with organizations focused on identifying emerging technologies. "[Artificial lift] R&D will help us keep our leadership position as new technologies replace older technologies," Lane said.

The Artificial Lift R&D Council, formed in 2005 with support from Weatherford and Texas Tech University, helped create TUHWALP in July 2012 to focus on the effective production of horizontal wells.

TUALP, which was founded in May 1983 by Zelimir Schmid, specifically addresses the artificial lift needs of the petroleum industry. In addition to its projects on CFD simulation of ESP sand erosion and artificial lift conditioning for deviated and horizontal wells, the organization also is conducting research relating to:

- Oil/water flow and emulsion formation in ESPs;
- CFD simulation of ESP performance under gassy conditions;
- Oil, water and gas three-phase ESP performance;
- Transient gas-lift modeling;
- Mechanistic modeling of ESP performance for single-phase and gas-liquid flows;
- Transient modeling of plunger lift;
- Modeling of artificial lift integration in production systems; and
- Self-stabilizing gas-lift valves to prevent casing heading.

"Artificial lift R&D is key to meeting new challenges," said Zhang of TUALP. "It also helps develop more efficient new designs and optimized operation strategies. This is probably more important when the oil price is low." ■

Each test well at the Artificial Lift Technology and Research Center has a dedicated flow manifold with three valves, which allows for texting systems at various flow ranges. *(Photo courtesy of Baker Hughes)*