Taking the Pulse of Producing Wells—ESP Surveillance

In mature fields and remote environments, active, real-time surveillance of electrical submersible pump systems brings both tangible and intangible value to producing assets. Downhole sensor data, unprecedented connectivity, powerful software and timely expertise help operators assess pump performance, predict pump failure, identify well problems and control pumps remotely. These new capabilities combine to decrease operating costs and increase production and cash flow.

3. In this article, run life pertains to the mean time between failures of the entire ESP system, as opposed to mean time between failures of a single pump.
More than 90% of producing oil wells require some form of artificial lift. Most of these wells reside in mature fields, also called brownfields. Artificial lift techniques are employed when reservoirs do not have enough energy to naturally produce oil or gas to the surface or at the desired economic rates. Most often associated with mature fields, this energy shortfall typically occurs when the reservoir pressure has been depleted through production. However, artificial lift strategies are used in a wide variety of wells, from high-rate deepwater wells with subsea infrastructure to the oldest wells in the oldest fields.

In mature fields, pressure support and secondary- and tertiary-recovery methods help extend reservoir life at the field level, but eventually the focus often shifts to managing individual wells. For example, wells in fields undergoing waterflooding often produce large volumes of water, necessitating the use of artificial lift to maintain economic oil-production volumes. In some fields, wells produce over 90% water, and increasing the percentage of produced oil by 1% can make a huge difference in economic viability.

Deciding which type of artificial lift system to deploy is a more complicated decision and involves evaluation of reservoir characteristics, such as temperature, pressure, optimal production rates and fluid properties, and well specifics—depth, inclination, completion configuration, surface facilities and the type of energy to provide the lift (right). The most commonly used artificial lift method is the rod pump. While rod pumps are simple to operate and generally cost less than other lift methods, they are less efficient and have a lower pumping capacity than other methods, especially in wells that produce at high gas-to-liquid ratios, through small tubing or from great depths.

Another artificial lift method uses a progressing cavity pump (PCP). Compared with other pumping methods, PCPs can be less costly, more reliable, less affected by produced solids—formation sand and scale deposits—and more volumetrically efficient than rod pumps.

Where a natural gas supply and a compression system are available, the gas-lift method is commonly selected because of its flexibility, adjustability and the ease of replacing associated equipment using slickline. Gas-lift systems are resistant to produced solids and are ideal for high gas/oil ratio (GOR) and high-angle wells. However, this method has reduced benefits as reservoir pressures approach abandonment levels, sometimes prompting a need for a different artificial lift method during the final production stages of fields.

Another, less common, artificial lift technique employs hydraulic systems to assist production. This technique can be especially beneficial in heavy-oil regions because it involves mixing light power oil with heavy produced oil to facilitate production and downstream processes.

The second-most common artificial lift method worldwide, after the rod pump, is the electrical submersible pump (ESP). This article reviews ESP development, how and where they work, and the conditions that reduce ESP system run life or cause failure. Next, we discuss

\[ \text{Typical Artificial Lift Application Range} \]

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\^ Artificial lift methods. The five most prevalent artificial-lift techniques include, from left to right, rod pumps, progressing cavity pumps, gas lift, hydraulic lift and electrical submersible pumps (top). The applicability of each method depends on well depth and production volumes (bottom), and many other factors, including produced-liquid properties, free-gas production, quantity and type of produced solids, production environment, well deviation, completion geometry, well location, available power supply and economics.
ESP surveillance, including its importance, enabling technologies and economic considerations. Examples show how timely ESP surveillance has created opportunities for operators to improve ESP performance, and well and field economics.

The Electrical Submersible Pump
More than 100,000 electrical submersible pumps are operating globally today. The majority of ESPs are installed in mature fields across the USA, Europe and Asia (right). Middle East ESP usage is expected to climb significantly in the next several years with increased requirements for artificial lift. Today, the dominant artificial lift method continues to be rod pumps, while ESPs have grown to be the second most common method since their introduction in 1927.

Pump surveillance—monitoring, diagnosis and control—has proven valuable in maximizing both the run life of the pump system and well performance. In many cases, surveillance actions are reactive, alerting operators to pump or power-supply malfunctions, or completion failures. Surveillance throughout the operational life of the ESP provides valuable information to identify the cause of failure should the system fail before its normal life expectancy. Real-time analysis enables the operator and supplier to make the changes required to increase run life without adding to well downtime. Pump surveillance also leads to proactive measures, prompting improved operating practices that increase pump run life, productivity and cash flow. In addition, it aids well-intervention planning before costly failures occur. Industry experts believe that two-thirds of producing wells on artificial lift could benefit operationally and economically from improved surveillance.

Acquiring essential ESP and well data is only half the solution. Using powerful interpretation tools, ESP experts can deliver an accurate and timely diagnosis and prescribe corrective action, making surveillance comprehensive and consequential. Problems identified through pump surveillance often reflect immediate or potential difficulties in a producing well. Operators engaging in real-time surveillance learn more than simply how an ESP is behaving; frequently, they find and cure well problems that are unrelated to the pump itself.

Data from ESP downhole sensors also may be useful in well testing to determine reservoir properties, such as pressure, permeability and skin. In addition, a multwell method exploits ESP data to ascertain spatial variations in reservoirs, for example anisotropy and fluid-interface changes.
Through the years, ESP technology evolved to address demanding operating conditions and production requirements by withstanding higher operating temperatures—exceeding 450°F (232°C)—and increasing gas and solids production. These systems are now deployed in well depths to 15,000 ft [4,570 m] and in casing sizes ranging from 4 1/2 in. to 13 3/8 in., delivering production rates from 150 B/D [24 m³/d] to 100,000 B/D [15,900 m³/d]. The determination of what size and type of ESP to install depends on well and completion geometries and the anticipated production characteristics.

Initially, an ESP is selected based on predicted completion performance, or flow rate. This usually involves examination of the well inflow performance relationship (IPR), which describes the production response to changes in bottomhole pressure (BHP). This relationship can be derived from the reservoir pressure and a stable well-production test. Since actual production depends on many factors, including tubing geometry, fluid properties and temperature, another relationship is constructed. This tubing-intake relationship describes the required tubing-intake pressure across a range of flow rates. When these inflow and tubing-intake relationships are plotted together, the intersection point on a common plot represents the well’s predicted flow rate. However, when the tubing-intake curve falls above the IPR curve, more energy is needed to produce the fluids (previous page, below). Properly selected artificial lift methods, like ESPs, add energy to the system, enabling reservoir fluids to be brought to surface.

Basic ESP systems comprise an electric motor, a protector, a gas separator, a multiple-stage centrifugal-pump section, a power cable, a motor controller, transformers and a power source (above). For monitoring of downhole well and pump-operating conditions, downhole instrumentation is also installed. Signals from sensors are transmitted through the power cable to surface remote terminal units (RTUs), allowing continuous sampling of pressures, temperatures, vibration, current and voltage.

Each centrifugal-pump stage within the pump section comprises a rotating impeller and a stationary diffuser. Fluids surrounding the rotating impellers are directed in both radial and tangential directions, resulting in circular upward movement of fluid to the next higher pump stage and eventually up the tubing. Stationary diffusers help convert the kinetic energy of the moving fluids into potential energy—pressure. This pressure energy is passed upward to the next stage.

5. The development history of the ESP dates back to 1911, when 18-year-old Armais Arutunoff started Russian Electrical Dynamo of Arutunoff (the future REDA). In 1916, a centrifugal pump was redesigned to operate with his motor, a major milestone that would lead to the use of motorized pumps downhole. After immigrating to the USA in 1933, he deployed the first oilfield pumping system in 1937 for Phillips Petroleum, now ConocoPhillips. Three years later, REDA Pump Company was established in Bartlesville, Oklahoma, USA, where it continues to manufacture pumps today. REDA became a division of Camco Incorporated in 1988, which was acquired by Schlumberger in 1998.
The pump rate, or discharge rate, is a function of the rotational speed, the number of stages, the dynamic head acting against an ESP and the viscosity of the fluid being pumped. These factors dictate the differential pressure across a pump system, and therefore the flow rate. However, for a given pump, there is an optimal design flow rate that maximizes pump efficiency and run life. For this reason, ESP manufacturers specify a recommended operating range (right). Operating within the manufacturer’s recommended range does not in itself ensure problem-free pumping. There are a variety of conditions and problems that experts must consider when designing an artificial lift system for a specific reservoir and well.

Problems in Pumping

While advances in ESP design have addressed many problematic production environments, the list of challenges remains extensive and includes high-gas volume wells, produced solids, and high-temperature and corrosive environments. Improper artificial lift system design also can make matters worse in both harsh and benign conditions.

Produced gas in oil wells can drastically affect pump performance and pump longevity. As the amount of free gas in the fluid approaches 10% by volume, gas lock can occur. Gas lock is a form of cavitation and causes pumps to surge and fail prematurely. At manageable free-gas levels, there are several ways to alleviate this problem. Maintaining a higher pump-intake pressure can keep free gas from forming downhole. Two ways to increase intake pressure are choking back production or placing the ESP lower in the well, thereby increasing the fluid-column weight above the pump intake.

Tapered-pump systems using multiple sections that progressively decrease in volume can reduce the risk of gas lock by reducing the free-gas volume to manageable levels. Another common way to manage the presence of free gas is to install a gas-handling device, or gas separator, below the pump section, allowing much of the gas to bypass the pump section. New technology such as the Poseidon gas-handling system has demonstrated the ability to manage free-gas volumes as high as 75% without gas locking, effectively increasing liquid-production rates and extending ESP motor life.

Another common challenge for ESP systems exists in wells that produce abrasive solids. Produced solids, including formation sand, proppant and scale, cause excessive wear when ingested by the pump. This is a major cause of ESP plugging and failure, and has led to the development of abrasive-resistant pumps. Improved understanding of formation sand-production mechanisms also helps combat this problem because operators now minimize sand production through optimized completion and production practices, including lift-system surveillance.

As well depths have increased, the challenges associated with ESP operations also have grown. High temperatures associated with deeper wells degrade ESP insulation and seal systems, eventually leading to motor failure. To meet the challenge, advances in high-temperature insulation and seal technologies have pushed ESP thermal ratings above 450°F. In addition to withstanding geothermal temperature, ESP motors create their own heat related to the pump load as a percent of the motor’s horsepower rating. The development of new variable-speed drive (VSD) controllers for ESP systems gives operators the flexibility to vary the speed of motors to pump optimal rates at variable frequencies, better managing power and therefore heat. The harder the motor has to work, the higher the internal motor-winding temperature. In addition, the fluid velocity past the motor must be considered for motor cooling.

Another detrimental aspect of high-temperature operating environments is accelerated corrosion by downhole fluids. At high pressures and temperatures, hydrogen sulfide [H2S], carbon dioxide [CO2] and certain well-treatment chemicals can damage seals, allowing entry of damaging fluids that attack critical motor components. Insulation material in cables used for powering ESP and data collection is also vulnerable in these environments. Across the industry, motor burnout attributed to water entry is one of the most common causes of equipment-related failures in ESP systems.

Improper system design or operating practices can also lead to ESP failure. In many cases, optimal pump operation is not possible because the artificial lift design steps failed to model the well’s inflow performance properly. This often results in undersizing or oversizing the ESP. When the ESP is oversized, the fluid in the well may be “pumped off,” causing the ESP to shut off automatically and remain off for a period of time to allow reservoir fluid to reenter the wellbore. Repeating this off-on sequence, called cycling, places tremendous strain on the ESP system, shortening run life and eventually leading to
failure. The use of VSD controllers helps reduce or eliminate cycling by allowing the operator to optimize the production rate for continuous pump operations. However, in some wells, VSD controllers are not economically justified. Nonetheless, accurate models and proper artificial lift design remain important vehicles to extend pump life and reduce lifting costs.

As in human health care, monitoring vital statistics helps reduce the risk of debilitating problems that lower life expectancy. New ESP surveillance techniques alert artificial lift experts to real or potential problems immediately and direct action, either by changing production practices, scheduling remedial work or altering ESP operation remotely using control capabilities. With an extensive list of potential problems, it is evident that the health of ESPs, and for that matter, wells themselves, is forever hanging in the balance.

Healthy Pumps for Productive Wells

In the past, the primary ESP monitoring method measured only motor current, plotting data on amperage charts at surface. This method is still common today and requires extensive manpower and regular wellsite visits to collect data and make necessary adjustments to pump and well operations.

A wealth of information is now available from downhole sensors to ensure optimal ESP performance. For example, the Phoenix MultiSensor artificial lift monitoring system for submersible pump completions continuously acquires intake and discharge pressures; intake, motor and discharge temperatures; and vibration and current-leakage data (right). Today, most pump monitoring uses supervisory control and data acquisition (SCADA) systems. However, SCADA system capabilities range from very limited to extensive, differing from field to field. In many cases, wells do not have SCADA systems. These capability gaps present challenges to operators and service providers wanting to exploit modern artificial lift monitoring systems.

ESP data must be delivered to the appropriate experts in a timely and secure manner to advance from a reactive approach to preventive and predictive workflows. Schlumberger has developed the espWatcher surveillance system for electrical submersible pumps to connect production teams to their wells and fields in real time, even on wells without SCADA installations. Secure, two-way communications permit the transmission of data from wells and instructions from remote artificial lift personnel back to the

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7. Cavitation in a pump occurs in relatively low-pressure wells when vapor cavities collapse upon reaching the high-pressure side of the impeller. This causes noise and vibration, and can lead to ESP shaft failure or mechanical fatigue of other components.


10. Supervisory control and data acquisition (SCADA) systems are a central gatherer of data from all instrumentation, and can initiate actions through linked controls or alert operators. The mnemonic SCADA is applied to everything from a fully integrated system operating nuclear power plants, for example, to a fit-for-purpose system managing a group of wells.
Surveillance in Mature Fields

In a quest to reduce costs and optimize production, Signal Hill Petroleum examined how ESP surveillance could help improve well performance. The Signal Hill Wilmington field in California, USA, is a mature asset with stable production and minimal well dynamics. Given the field’s age, engineers weighed the cost of investing in new technology against the potential benefits of real-time ESP surveillance. Signal Hill elected to install the Phoenix MultiSensor and espWatcher systems on the Signal Hill East Unit 15 well.

Within two months, real-time ESP surveillance began to yield results. Once the pump was started, production engineers noticed that the pump-intake pressure was 150 psi [1.0 MPa] higher than designed. Since they did not see a clear reason for this higher pressure, the engineers began investigating the anomaly. The engineers determined that the high pressure in the production well was caused by a flow-eroded choke for a nearby injector causing an injection rate 350% higher than planned. The higher than planned injection rate also contributed to a higher water cut in the producing well. The excess water was both wasting power and reducing oil production (see “Managing Water—From Waste to Resource,” page 26).

Once the problem was identified, Signal Hill technicians repaired the damaged choke and controlled the injection rate, which in turn lowered the water cut in the producing well. As a result, the intake pressure recorded by the MultiSensor system fell to a level in line with design criteria (next page, bottom).

Pump surveillance also helped Signal Hill to identify problematic well operations that could have damaged ESPs and reduced cash flow. Just after well startup, an anomalous spike in the pressure and temperature data was determined to be from a weekly chemical treatment. To perform the chemical treatments, field operators were shutting the flowline, allowing the pump to run against a closed valve, which ages and damages an ESP. Signal Hill altered the chemical-treatment process so that the well did not need to be shut in, extending ESP run life and increasing cash flow. These disruptive operating practices had not been identified by earlier monitoring methods.

On another occasion, a Schlumberger artificial lift specialist received an espWatcher alarm message on his mobile phone when ESP threshold levels were exceeded. The expert notified Signal Hill engineers, who found that the pump had been shut down to change a leaking valve downstream, interrupting the critical startup period. Engineers restarted and monitored the ESP remotely in real time, ensuring a proper startup.

Signal Hill has also exploited the remote command capabilities of the system to shut down the ESP for routine maintenance and to increase pump speed based on downhole pressure measurements, increasing power frequency using VSD controllers for maximum production. The espWatcher and MultiSensor technologies have improved pump and well operations, and have helped boost production by 70%.

In ESP completions that produce significant volumes of gas, bringing wells on line quickly to achieve stable flow with minimal downtime can be a challenge because of ESP cycling. Cycling is a series of regular start-stop events that reduce pump run life and defer production. Aethon I LP in Dallas, Texas, USA, deploys VSD systems and the espWatcher service for pump surveillance in their midcontinent and Permian Basin, USA fields.

Field status at a glance. A screenshot from the espWatcher service demonstrates how it helps ESP experts evaluate field uptime from a single display that ranks wells by alarm status and according to deferred oil-production volumes. Green, yellow and red surveillance codes indicate the status of the wells. For a given well, the green code shows that the pump is operating normally. A yellow alarm code means that there are potential well or pump problems, while a red alarm code tells the surveillance expert that the pump has shut off or there is no communication with the wellsite.

Pressure, temperature and amperage during critical pump-startup operations. After starting the pump (A), Signal Hill engineers observed the intake pressure stabilizing at 300 psi [2 MPa], much higher than the predicted pressure for optimal pump operations. After investigating the causes for the pressure increase (E), the company determined that a flow-eroded choke elevated injection rate on a nearby water-injection well, causing excessive pressures and water production at the ESP well. Once the choke was repaired, the ESP intake pressure progressively dropped to the anticipated design pressure (E to G). The event at B resulted from a weekly chemical treatment-injection procedure, in which the well was shut in against the running pump. This practice shortens pump life. A changed procedure was applied (D) with no significant effect on pump power parameters. Events C and F represent pump shutdowns, prompting an immediate alarm message to the Schlumberger ESP engineer. It was known that a greater drawdown could be applied to the well, and increasing the VSD frequency to the pump motor at G resulted in increased production.
Continuous ESP cycling caused by well unloading characterized the typical well startup. However, real-time surveillance enabled Aethon to carefully observe the effects on cycling. For example, on the SWNLU 35-18 well in SW Nena Lucia field, the ESP operating frequency was adjusted downward from 63 Hz to 61 Hz, resulting in an efficient, trouble-free well startup (below). Previously, engineers and technicians would spend an average of seven days optimizing pump performance upon startup, making repeated visits to the well to examine amperage charts and to make pump adjustments.

Aethon engineers have discovered well problems using the espWatcher service. Shortly after bringing the Warder 39 well on line, Aethon and Schlumberger engineers observed that the well was not behaving according to design, so they analyzed the ESP pressure and temperature data. To ensure that the pump was running in the proper direction, engineers checked the direction of ESP rotation by reversing rotation direction and observing the results. This standard procedure had the pump experts confirm that the original installation wiring and pump-rotation direction were correct by monitoring the intake pressure. When the impellers rotate in the wrong direction, they operate less efficiently, resulting in a higher than design intake pressure and a well that is underproduced.

After the pump was returned to its original and correct configuration, it was allowed to run for several days without interruption. An anomalous increase in both motor and intake temperatures was observed (bottom left). This can occur when pumped fluids are circulated back down to the pump intake through a leak in the tubing. The problem was quickly diagnosed using the espWatcher service. The completion was pulled until the leaking joint was replaced at surface, and then the string was run back in the well. The result was a saved pump and restored production.

Abundant real-time and historical ESP data, translated into information to enable decisions, have led to increased well uptime, longer pump run life, and fewer interventions and wellsite visits. Moreover, proper pump diagnoses and efficient maintenance schedules are supported by timely data from multiple sensors, so well work can be prioritized and matched to available resources. Aethon now benefits from the espWatcher service on more than 300 wells.

Managing Remote Wells

Operators of remote wells in South America must keep ESPs healthy and running to meet production targets. This can be an enormous challenge because many wells are difficult to access and experience frequent power failures that shut down ESPs. In many cases, stand-alone generators powering one or more wells fail because of poor fuel quality or clogged filters. Without real-time surveillance, these shutdowns often go undetected for many hours.

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**Identifying well problems through ESP surveillance.** Aethon noticed that well performance did not match that predicted in earlier well-test analysis. After performing a routine check to verify pump-rotation direction (Point 2 to Point 3), Aethon closely monitored ESP data until Point 4, 12 days later. Both the motor temperature (yellow) and intake temperature (dashed green) increased during the monitoring period, confirming the existence of a problem. Analysis of the anomalous temperature increases suggested that the produced fluids were being recirculated within the well. The completion was pulled until the leaking joint was replaced at surface, and then the string was run back into the well.

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Persistent power failures, when not corrected immediately, severely impact field economics by reducing cash flow. Producing companies in South America have been able to significantly reduce the response time to correct ESP shutdowns caused by power failures (right).

Like many fields around the world, oil and gas fields in South America are subject to the damaging effects of produced solids, such as sand, scale and paraffins. These solids can block critical flow-paths, causing increases in intake pressure and motor temperature, and eventual failure of the ESP. Using the espWatcher surveillance system, one South American operator was able to promptly identify a decline in pump efficiency and quickly elected to pull the pump (below right). Upon inspection, the operator found that the pump intake and pump stages were blocked with a mix of sand, scale and paraffin. In all likelihood, this ESP motor would have failed in a matter of days if this problem had not been detected.

Remote real-time surveillance and control of ESP systems have dramatically improved the way operators address ESP shutdowns and potentially damaging situations that are commonplace in remote well operations. The use of espWatcher alerts and alarms, coupled with remote ESP startup, shutdown and speed-control functionalities, has made difficult field operations more effective, efficient and profitable.

A Future Lift

The ability to transform the large amounts of available data into useful information enables pump manufacturers to continually improve ESP hardware to meet the rigors of oil and gas production. Some advances better protect motors and pumps in harsh environments, while others have markedly improved ESP performance in difficult production conditions, as in wells with high volumes of free gas. Service providers have improved ESP deployment methods. For example, ESP systems can now be deployed on coiled tubing, offering advantages for rigless operations, in environmentally sensitive locations and in pump-only installation workovers. The industry is also moving ahead in the critical area of process workflows.

Key elements to a successful artificial lift optimization program include the effective use of new technology, accurate modeling, technical expertise and connectivity. The Schlumberger LiftPro service provides a consistent workflow to diagnose and optimize underperforming artificially lifted wells. Within a systematic optimization process, experts use real-time, episodic and historical data to identify potential candidates and formulate remedies. Along with accurate flow-rate information, including data from a new generation of multiphase flowmeters, data from ESPs are crucial in the LiftPro candidate selection and optimization processes. Real-time surveillance through the espWatcher system, along with knowledge gained from transformed data, is the enabling technology that connects experts to pumps and moves production management from a reactive process to one that is proactive.

In the oil and gas industry, real-time surveillance of production systems, reservoirs, wells and fields is moving to a new level. These advances are redefining production optimization and reservoir management. Within this large domain, ESP surveillance helps keep the oil flowing from the reservoir and plays a key role in ensuring healthy wells, fields and reservoirs. —MGG