Stopping the sand

Technology manages solids production in artificial lift wells.

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The best way to manage solids production is by optimizing the initial completion and maintaining it over the life of the well. But even in carefully planned and managed wells, restimulation and drawdown can result in unexpected formation deconsolidation or solids release that hinder production and damage artificial lift equipment.

For electric submersible pumps (ESPs), progressing cavity pumps (PCPs) or rod pumps, excessive solids production has traditionally led to downhole and surface equipment failures, poor well economics and even shut-ins. However, three recent case studies demonstrated that domain expertise could provide new options for economic solids management to maintain hydrocarbon production.

Manage ESP settings to extend runlife

When Bahar Energy reviewed its mature, gas-lifted wells in the Gum Deniz oil field of Azerbaijan, an economic analysis indicated that converting to ESP lift could improve production and profits. Therefore, the operator decided to convert one well to ESP lift. The first three ESPs supplied by a third-party service provider failed in less than one month due to excessive solids production—a problem that had a minimal effect on gas-lift system performance.

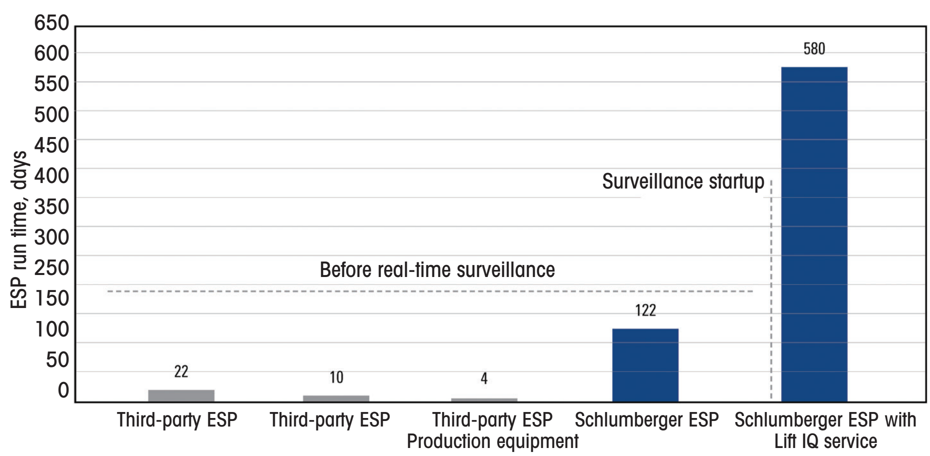

FIGURE 1. Real-time surveillance helped Bahar Energy substantially improve ESP runlife without installing additional completions equipment in an offshore well in the Gum Deniz Field. (Source: Schlumberger)

Project economics and logistical challenges limited the operator's options to extend ESP runlife with new completions equipment or upgraded ESP specifications. Instead, Schlumberger recommended a fit-for-purpose REDA ESP system, which lasted for 122 days. To further extend ESP survivability, Bahar Energy added a new ESP system from Schlumberger and also added the Lift IQ production life-cycle management service, transmitting downhole and surface data to an Artificial Lift Service Center for real-time analysis, troubleshooting and remote adjustment. Experts monitored ESP system threshold alerts and made real-time recommendations for remote setting changes to prevent problems such as pump motor overload from high sand volumes and motor underloads from gas slug breakthrough.

As a result, Bahar Energy minimized unnecessary ESP shutdowns that stress submersible equipment. After 580 days, the ESP was still operational despite the harsh conditions, demonstrating that real-time monitoring and troubleshooting can help manage downhole equipment performance without a technical upgrade or additional sand management equipment (Figure 1).

Preventing PCP plugging

Casabe Consortium uses PCPs to produce wells for Ecopetrol in Colombia. In some wells, extreme sand production results in plugging of the PCP intake, which leads to frequent interventions, deferred production and high opex as the wells are shut in until such time that sand can be removed. An evaluation of robust sand control systems determined they were uneconomical for the project.

Schlumberger recommended the Left Helix PCP, which incorporates two changes to a conventional PCP design to reduce future plugging risks. First, the conventional PCP bottom tag is replaced by a top tag, which increases the flow area at the intake. In addition, a second rotor is added to the rotor string to pump a small fraction of the total rate downward (reverse geometry) and prevent sand accumulation at the pump intake (Figure 2).

Casabe Consortium installed Left Helix PCPs in two pilot wells. In the first well, the Left Helix pump eliminated interventions and deferred production related to sand flushing, enabling incremental production valued at $50,000 at $50/bbl. In addition, the improved sand management enabled increased drawdown, improving oil production by 13%. Finally, the new pump doubled the PCP runlife from an average of 363 days to 732 days, further reducing interventions and production deferral.

Conditions in the second well were considerably more challenging, resulting in more downtime for sand flushing as well as an average runlife of just 78 days with conventional PCPs. In fact, the well had been shut in for nearly a year because Casabe Consortium could not justify its economics. As with the initial well, the improved sand handling eliminated flushing interventions and deferred production, enabling incremental production valued at $331,000. Drawdown also was increased by 13%, and the Left Helix pump more than tripled the conventional PCP runlife to 275 days, further reducing deferred production.

The improvements in runlife increased well production and reduced intervention frequency and associated costs. The success prompted Casabe Consortium to install the technology in 12 additional wells.

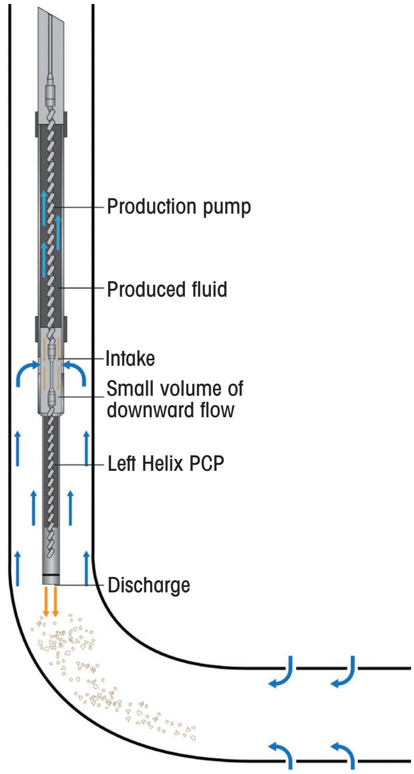

FIGURE 2. The Left Helix pump design incorporates a bottom rotor to pump a small percentage of fluid downward, which prevents sand accumulation at the intake. The design also replaces the conventional bottom tag with a top tag to reduce plugging risks. (Source: Schlumberger)

Protecting the rod pump

In the Permian Basin, rod pumps are carefully selected and engineered to maximize the lifetime for particular well conditions. Each downhole rod pump is designed with a specific clearance in relation to fluid viscosity and stroke speed, among other factors, to maximize production and pump efficiency. When the barrel and plunger are severely abraded by sand and solids production, clearance increases beyond the optimal range. The increased clearance results in increased fluid slippage, reduced pump efficiency and, in the worst case, a stuck plunger.

A leading operator in the Permian Basin asked for a solution to severe abrasion cutting in several wells with pump runlife ranging from 84 to 364 days. Schlumberger recommended adding a Don-Nan sand diverter, which is a modified plunger adapter that directs sand and solids away from the pump barrel. Compared with the conventional design for plunger adapters, the sand diverter has an increased outside diameter, providing a much closer fit, and a beveled leading edge with upwardly angled discharge ports. This combination of design features prevents sand and solid material from collecting between the barrel and plunger during operation or while the system is idle.

The operator installed Don-Nan sand diverters in 15 sand-challenged wells. Runlife for the pumps increased on average by 171 days (108%). The most improved well more than tripled its runlife (335%).

Sand production solutions

When recompletion and conventional sand control and remediation measures are uneconomical, as in the case of a mature well or field, operators must find alternative solutions that allow continued production to maximize the value of their substantial investments.

Improvements in material properties and hardware performance help ensure the longevity of downhole equipment even in harsh environments, and continuous improvement efforts have extended lifting equipment capabilities and lifetimes far beyond the expectation of even a decade ago.

Finally, by combining these physical improvements with increased digitalization and the Industrial Internet of Things, artificial lift systems can begin to respond automatically to the presence of sand and other damaging conditions. From a foundation comprising decades of artificial lift expertise, these next-generation systems automatically optimize performance for downhole conditions or predict impending failures early enough to preschedule an intervention or a change in artificial lift technology. The result is better economics and more efficient reservoir drainage, even in severely sand-challenged wells. E&P