AS SEEN IN
OCTOBER 2017
E&P

Getting a boost

A workflow was designed for selecting the optimal type of artificial lift for reactivating abandoned wells.

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Challenging oilfield economics are incentivizing producers to increase asset values by extending production in mature reservoirs, even reopening abandoned wells rather than launching new drilling campaigns. Artificial lift has a key role to play in this growing trend. The tried-and-true methods, including electric submersible pumps (ESPs) and rod pumps, continue to prove themselves as worthy workhorses in bringing old wells back to life.

Emerging with the growing trend is a strategy for selecting the most appropriate artificial lift method to reinvigorate a particular field or well. Rather than relying on guesswork, familiarity with a certain type of artificial lift or bias toward one method or another, reservoir and production engineers are recognizing the benefits of using quantifiable field data to measure a field's economic and technical potential and develop a streamlined workflow for selecting a customized lift approach for the entire life cycle of the well.

Engineering an artificial lift strategy that balances economic factors with specific well application considerations can be a game changer for exploiting complex reservoirs where recoverable reserves remain by extending equipment runlife, reducing the cost per barrel of oil and boosting incremental production. A workflow designed to maximize artificial lift reliability and performance was implemented in a mature field in South America, for instance, as the centerpiece of a strategy for the reactivation of 10 abandoned wells.

FAILURE CAUSE IDENTIFICATION

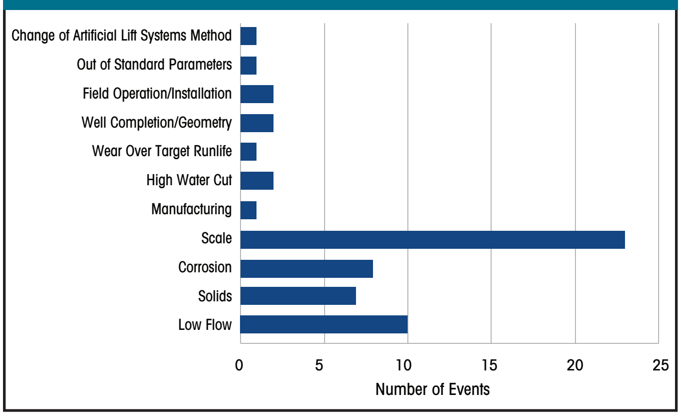

FIGURE 1. This chart shows the failure distribution for the sample wells. Post-failure analysis identified failure cause for 58 events for the sample wells. As scale failures were seen in the same well, this was a well-specific problem rather than a field trend. (Source: Schlumberger)

Designed to simplify the process of selecting the artificial lift method that best suits operator objectives, the Schlumberger LiftSelect strategic production planning service uses available field and reservoir data to model well behavior. The service combines the vast amount of data from conventional manual workflows to streamline the decision-making process for selecting the optimum artificial lift method for a specific well.

An initial screening of the field narrows the options using software that evaluates the seven major types of artificial lift against well criteria. Those include well depth and deviation, downhole temperatures and pressures, produced fluids and solids, availability of power, and surface facilities and flow assurance issues such as paraffins and solids production.

The service also has the capability to calculate results as production rates, cumulative volumes, capex, opex, net present value and pump properties. Single artificial lift evaluation simulates well performance using one method for a given period and compares methods. Scheduled lift analysis helps optimize a schedule for transitioning between lift methods. Full lift optimization determines the most appropriate lift method for each phase of well life, including natural flow if applicable.

Reactivating 10 abandoned wells

Considerations for reopening abandoned wells include deep installations, low production rates and problems related to flow assurance, which often result in premature artificial lift equipment failures and repeated interventions that impact the field's ability to produce from an economic standpoint. To develop a strategy for extending production in these wells, it is essential to understand the issues that led to the abandonment in the first place.

Discovered in 1970, a challenging mature field in South America provided a sample group of 10 abandoned wells with varying production characteristics and well profiles to introduce the workflow for artificial lift selection. None of the wells had the ability to flow naturally, yet if reactivated, the wells' combined production potential could deliver at least 1,000 bbl/d to the overall field production.

Nine of the wells were drilled in the last decade, and one well was drilled in 1981. Because of the field infrastructure and design, all of the wells were initially completed with conventional ESPs for artificial lift, a method that offers wide flexibility and operating range over the life of the well.

However, changing reservoir conditions, rapid production declines in the first months after the wells were brought online, scale buildup around the equipment and design input uncertainties related to reservoir properties resulted in multiple pump failures traced to 58 events, according to a post-failure analysis (Figure 1). Most of the wells averaged two interventions per year to address low flow rates, solids, corrosion and scale. The reservoir also showed a lower productivity index than was initially anticipated, meaning the artificial lift equipment was oversized for the application. As a consequence of these factors, the wells were temporarily abandoned.

After attempting different ESP configurations with various vendors, the operator decided to take a holistic approach to reactivating the wells using an engineered workflow that factors in the conditions and characteristics of the field and the wells to evaluate the applicability and likely success for the seven types of artificial lift: ESP, sucker rod pumps, gas lift, progressive cavity pumps (PCPs), rodless PCPs, plunger lift and hydraulic jet pumps.

The sample wells were designed with deviated "S" and "L" shapes and vertical geometries, and each well was analyzed using the workflow to determine the optimal artificial lift strategies. Based on the depth and deviation of these wells, with pump setting depths between 2,896 m and 3,048 m (9,500 ft and 10,000 ft), the workflow narrowed the artificial lift choices to ESP and rod pumps. Plunger lift-assisted gas lift was eliminated due to the lack of a gas source, and capital investment necessary to build a gas-lift infrastructure. PCPs are not recommended for applications deeper than 2,000 m (6,500 ft).

Designed for performance

The workflow also identified equipment performance risk factors. With the methods narrowed down, the engineers then focused on specific design details to reduce the risks, conducting in-depth comparisons between the two approaches. Final equipment designs would need to accommodate both long- and short-term conditions for maximizing efficiency and equipment runlife. LiftSelect created a variety of production scenarios by setting sensitivities on variables, including flow rates, gas-liquid ratio and amount of produced solids.

ESPs were selected as the best artificial lift option for four of the wells. However, based on the root cause analysis of the previous ESP failures, including radial bearing abrasion, erosion wear and low pump efficiency due to low production and mechanical wear because of operating at downthrust conditions, the engineers designed a more robust ESP tailored to overcome those challenges. The new design includes abrasion-resistant materials to increase shaft stability and toughness, compression construction to minimize mechanical wear downthrust, an optional motor with a shroud to enhance fluid velocity in low-flow conditions and a gas-handling device for nonanticipated or pump-off conditions. The designs also were engineered to achieve operating efficiencies as low as 25% to provide a wider flow rate range (Figure 2).

For the remaining six wells reduced-footprint hydraulic rod pumps, compared to conventional rod pumps, were considered the best option. Because the field had originally been designed for ESPs, only 3 m (10 ft) exists between the wells, leaving no room for a large conventional pumping unit. For these wells the equipment can reach a minimum pumping speed of 1.5 strokes per minute to enable effective pumping when production rates decline. Corrosion-resistant materials were selected to extend pump runlife, and a high-strength rod was designed to ensure performance with high rod loads in the deep wells. E&P

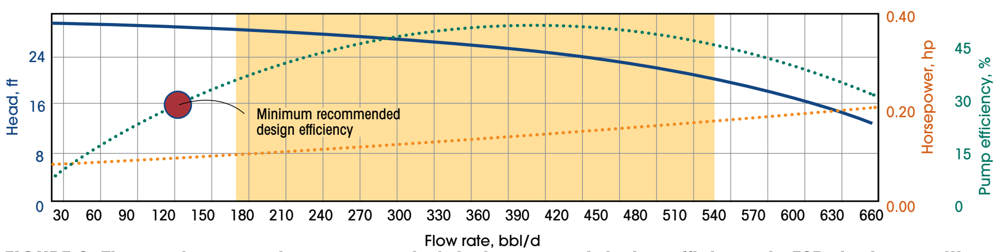

FIGURE 2. The most commonly recommended design or used design efficiency in ESPs is shown with operating range from 200 bbl/d to 650 bbl/d. (Source: Schlumberger)