Electric Submersible Pumps for Artificial Lift Intelligence

Once considered suitable only for high-cost, high-productivity developments, intelligent well technology is increasingly being used to enhance the value of maturing assets. Wells equipped with electric submersible pumps (ESPs) are particularly suited to this blend of old and new. Already equipped with downhole electric cables and protectors, ESP wells are easily fitted with monitoring and control devices at a relatively small incremental cost.

Intelligent control is not exclusive to complex and highly instrumented wells. Its use also has the potential to revolutionize production practices in mature fields. Some operators have already discovered that coupling real-time control with electric submersible pump operation can reap substantial rewards.

For years, operators have been monitoring and controlling the performance of ESPs from the surface. Operators can avoid early pump failure by adjusting the frequency of the signal sent to the pump’s variable-speed drive motor controller. This adjustment can also be used to avoid underloading an ESP and increase production volume. To find this optimal middle ground, engineers use real-time data and modeling to design the pump to fit the specific requirements of each well. Two-way remote communication provides operators with pump performance oversight and control from considerable distances.

More recently, engineers have taken the concept a step further by mixing components of intelligent technology aimed at reservoir management with ESP remote monitoring and control. A

Monitoring and control with an espWatcher surveillance and control system for ESPs. After the pump was started on a West Texas well, intake pressure was measured (A) and seemed to be stabilizing above 300 psi [2.1 MPa], which is about 150 psi [1.0 MPa] higher than the design estimate. A damaged choke on an adjoining injector was repaired and the injection rate controlled (E), resulting in a 200-psi [1.4-MPa] flowing pressure that was much closer to design criteria. Unexpected spikes (B and D) during a weekly chemical treatment process were caused by shutting the flowline while the pump was running. The production engineer quickly found that the field operator had shut the well down to change a leaking valve downstream (C). The engineer started the pump remotely, ensured proper initial operation, and monitored events during the initial drawdown. Later, the well was shut down and started remotely to perform routine maintenance and then restarted (F). The variable-speed drive frequency was increased to maximize production (G).
control. This combination enables significantly increased flow rates or ultimate reserves recovery by optimizing pump performance. In multizone completions, surface-actuated downhole flow-control valves allow operators to change or shut off flow from distinct producing zones within a well without intervention costs and risks. Permanent downhole pressure and temperature gauges that monitor production zones at the sandface indicate when to open a new zone or shut in a failing one without having to first run a production log to identify the offending water or gas producer.

Use of intelligent flow control devices and sensors helps direct work done by the ESP toward lifting more oil and less water, achieving greater drawdown in production zones. The pump is also subject to less damage from slugging and gas in the flow stream while allowing operators to use smaller ESPs, gas separators and gas-handling equipment. Furthermore, flow control valves allow operators to protect formations during workover operations in ESP-lifted wells (right).

Despite these advantages, intelligent technology in ESP-lifted wells has long been perceived as a luxury suitable only for major and large independent operators. Traditional monitoring methods—including plotting measured electric current data at the surface to determine pump efficiency and using acoustic measurements to determine fluid levels—are still employed on the majority of these wells. Such practices are inefficient and labor-intensive as they require frequent wellsite visits to collect data and to manually adjust pumps.

Recently, however, some small operators of mature oil-producing provinces—where low-pressure fields on artificial lift account for the vast majority of oil and gas production—have begun to embrace real-time data processing and interpretation to lower costs while improving reservoir management. Many of these operators have learned that mixing intelligent technology with ESPs is especially effective in wells with zones prone to water production. For example, one operator in Indonesia set a single on-off valve to control inflow from a water-prone, lower zone. A strain gauge at the bottom of the well detected water in the production stream by measuring the hydrostatic pressure difference created. Upon detection of water, the zone was then shut off until the water cone relaxed. The zone was later brought back on line until the situation redeveloped. Repeating this cycle allowed the operator to extract 100,000 barrels [15,900 m³] of oil from the lower zone that would have been bypassed.

**Increasing Remote Monitoring and Control**

Through increasingly sophisticated applications such as the Schlumberger Advanced Lifting Service and the espWatcher surveillance and control system for electric submersible pumps, data on ESP performance and downhole and surface power are captured from the wellsite in real time. The data are sent to a hub to be analyzed by experts who can remotely take such actions as ESP starts, stops and speed control.

Data are also processed and compared against preset alarms based on pump, motor, well and reservoir performance limits. Alarms can be sent to interested parties by pagers, e-mail, cell phones and faxes. Because experts are able to analyze the cause of and find solutions to the pump failure, these processes allow wells to be brought back on line remotely and within a very short time of having stopped. The cost advantages, in terms of labor costs and avoided lost production, can be significant.

When sophisticated computer simulation and engineering software packages are brought to bear, pump behavior can be modeled based on in-situ fluid data and compared to bench-test performance curves for each specific pump. Well performance is then analyzed against the well model. Pressure data at each node, combined with completion and fluid properties information, provide periodic well and reservoir diagnostic checks and easy identification of underperforming ESP wells.

In an example from the Permian basin in West Texas, an espWatcher system recorded pump data in real time (previous page, bottom). After the pump started, the well stabilized at a pressure higher than the design estimate. Over the next few weeks, the trend showed that a damaged choke on an adjoining injector well was causing injection at 3½ times the desired rate. The increasing water cut was wasting power. The operator repaired that choke and controlled the injection rate, resulting in a flowing pressure that was much closer to the design criteria.

In addition, unexpected spikes were found to be caused by a weekly chemical treatment process in which the flowline was shut while the pump was running. This process was revised so that the well could continue to flow during treatment and the pump motor temperature increase would be negligible. This type of event is much easier to identify with pressure and temperature measurements than with traditional amperage measurements.
A Wytch Farm first. The M-15 well was the first with a surface-controlled flow control device installed below an ESP. Flow control devices were set around 5,300 m [17,390 ft] at a point where wellbore deviation was more than 85°. A flowmeter above the ESP and a MultiSensor well monitoring unit for submersible pump completions below it enable monitoring of well performance.

Benefits derived from these real-time remote monitoring and control tactics are sometimes dramatic and immediate and often return operator investment quickly. In another West Texas well, for example, a small operator was spared the significant expense of replacing a motor destroyed by overheating when real-time data triggered an alarm system and alerted an engineer to an impending problem. Another operator optimized and sustained production by continually monitoring well performance and adjusting pump speed to match performance.

Intelligent well technology with hydraulically or electrically actuated downhole flow control in ESP wells is the next logical step to real-time remote monitoring and control. For example, a key element in ESP sizing is the productivity index (PI) of a target zone. Measured as barrels produced per psi of drawdown, a wrong PI value, or more commonly one that has changed over time, often results in higher or lower flow rates than specified in the pump design. Such a condition would cause pump stress through overloading or less than optimal production due to underloading. With a variable-setting intelligent flow control valve acting as a choke at the sandface, the operator can increase or reduce flow into the wellbore and so adjust drawdown. The variable-speed drive can then be set to optimize pump performance.

Proofs of Concept

Equally important in optimizing production in ESP-lifted, intelligent wells are the enhanced monitoring capabilities of downhole pressure and temperature gauges. These permanent sensors allow engineers to calculate flow from pressure differentials measured across a restriction and to determine density from hydrostatic pressure differences measured along the length of the well.4

Downhole flow control and an ESP were first combined in a single completion in 1999 when BP used the strategy to control water production at the M-15 well at its Wytch Farm field in Dorset, England. The Wytch Farm field was a proving ground for extended-reach drilling during the 1990s and was also the site of numerous drilling records, including the first 10-km [6.2-mi] extended-reach well. Besides being a leading testing ground for enabling technologies such as rotary steerable drilling tools, the project made it possible for BP to drill to environmentally sensitive offshore reserves from onshore locations.

The M-15 well was constructed with two laterals connecting fault-separated reservoir sections. When it was drilled, the Wytch Farm field M-15 well set records for, among other things, the longest reach of any multilateral well—3,400 m [11,155 ft]—for the northern lateral, and the greatest length—1,800 m [5,905 ft]—of perforating guns. The completion included a REDA electric submersible shrouded pump and three hydraulically actuated, side pocket-mounted wireline-retrievable flow control valves (WRFC-H) with six settings including fully opened and fully closed (left). In an industry first, one of the flow-control devices was installed below the ESP. The well was also equipped with a flowmeter above the ESP and a MultiSensor well monitoring unit for submersible pump completions immediately below the ESP. The flowmeter measures total flow through the pump. The MultiSensor system measures temperature, vibration and intake pressure in the lateral and uses the pump cable for signal transmission.

BP first produced the north lateral for about six months with the WRFC-H fully opened. It was then shut in. At the time of shut-in, it was producing about 11,000 bbl/d [1,748 m3/d] of fluid, 3,000 bbl [473 m3] of which were oil. The southern lateral was then fully opened while production from the northern lateral was controlled. Combined production was stabilized at 4,000 bbl/d [638 m3/d] of liquid with a water cut of 25%. Net oil production was thereby equal to that of the north lateral before it was shut in.4 As a consequence, the operator was able to control expected early water influx and in so doing recover 1 million bbl [158,900 m3] of additional oil.

Downhole flow control and permanent sensors were used in a similar manner on the world’s first TAML Level-6 multilateral well drilled and completed by China National Offshore Oil Company (CNOOC) in 2002 (next page).4 Again, the hydraulically actuated valves were used to minimize water influx and selectively control flow from each of two laterals on the NE Intan A-24 well in the Java Sea, offshore Indonesia. MultiSensor gauges provided real-time pressure, temperature and flow-rate measurements for each branch, and a REDA ESP lifting system optimized oil production.

By combining the advantages of ESPs, multilateral wells and remote monitoring and control, CNOOC was able to reap benefits beyond water control. The multilateral configuration maximized the company’s return on investment by allowing drainage of the same reservoir

through two wellbores, while using only one well slot and saving the cost of drilling and completing the upper section of a second well. At the same time, intelligent well technology allowed the operator to monitor and control flow from each lateral remotely and so easily manage the reservoir for increased production and reserves recovery.

New Demands, Old Solution

Many ESP-lifted wells benefit from intelligent well technology through better reservoir management, particularly by reduction of premature water production. The ability to determine the source of water production and then minimize it in multizone completions has been used around the world with the repeated result of increased production and reserves recovery rates.

The expectation is that ESP-lifted intelligent wells will become even more attractive as the industry moves increasingly to oil production from remote areas where high volumes of water can generate significant costs. Offshore, for example, the ability to prevent water from reaching the surface and taxing limited platform-based processing facilities has spurred the industry to spend millions of dollars researching methods to remove and dispose of water downhole.

Since such subsurface water separation technology is yet to be proved and some of the industry’s most expensive deepwater projects are lifting large volumes of oil with ESPs, downhole flow control chokes and sensors may be at least an interim solution to unwanted water production.

—RvF