Intelligent Pumps Last Longer

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By equipping pumps with sensors, operators can realize major benefits that include longer life, more efficient performance and improved production.

With sensor-equipped electrical submersible pumps (ESP), downtime can be minimized, unplanned costs can be eliminated and production optimized. In California, an operator experienced a power outage. When the field was restarted, one unit set off a motor temperature alarm and was automatically shut down. After investigation, the well was stabilized, restarted and returned to service, eliminating a costly pump failure and potential lost production revenue.

As ESPs prove more reliable, they are becoming the lift system of choice across many applications. Whether the wells are prolific producers or marginal producers, whether they produce clean oil or a small amount of crude with lots of water, pump performance can be optimized. The benefits include extended pump life, improved performance and reparability. With today’s high commodity prices, preventing pump downtime and failures can bring added benefits in production improvement.

Today, many ESPs are equipped with sensor packages that collect a variety of data and transmit the information back to surface by multiplexing it on the power cable. The data are subdivided into two categories depending on the intended use—pump performance and production optimization. A few basic measurements of key performance parameters such as pumping pressure, motor winding temperature, vibration, RPM and current leakage—coupled with pump intake and pump discharge pressure—can help diagnose pump performance. Minor adjustments from the surface can often keep the motor running at maximum power factor and efficiency, but when wear and tear inevitably cause pump performance to decline, the data provide early warning in time to schedule a replacement before the pump suffers irreparable damage and defers production.

For example, in a field in Western Siberia, pumps diagnosed in incipient failure mode are scheduled for replacement. They are pulled before they fail and replaced by new or rebuilt pumps, and the pulled pumps are returned to the nearby factory where skilled technicians rebuild them. Only a few are sent to the scrap heap. Because replacement is planned in advance, the interventions can be scheduled and performed efficiently with minimal interruption of production.

Advanced Lifting Services
Saving good equipment from premature failure is only part of available advanced lifting services. The operator can greatly benefit from the optimization of production from all the wells that comprise the asset via an additional sensor package installed on the pumps. Gauges can be installed on each pump to provide production information that can be analyzed and entered into an asset’s dynamic reservoir model. With dynamic temperature and pressure information, along with flow rate derived from pump volumetrics and speed, all the pumps in the asset can be tuned to optimize asset performance. Pump variable speed drives can be accessed remotely by the monitoring and surveillance team and adjusted to deliver peak performance.

Continuous Monitoring and Surveillance
Since many ESPs are installed in remote wells where it is impractical for them to be continuously monitored manually, the performance data are automatically transmitted via land line or satellite to a central production facility. There, a minimum number of skilled employees can monitor thousands of pumps from wells separated by hundreds of miles. Automatic alarms alert the employees when a pump’s performance drifts out of a predetermined normal operating range, so they can immediately focus on it, diagnose the problem and take remedial action.

Using integral pump gauges, an operator in Eastern Ecuador recently performed pressure transient analysis on a reservoir. Creating pressure pulses by switching the pumps on and off, pressure buildup and drawdown were recorded, and a transient was identified. Analysis revealed formation damage had created skin effect in excess of +25 that robbed
58 percent of the reservoir pressure, and indicated that the wells were seriously underperforming.

From the data, a Nodal analysis was run that postulated several solutions for different values of skin effect. It showed that if skin were completely removed, net production could be improved by 330 percent. Accordingly, based on the information from the downhole monitoring system, an aggressive matrix treatment was prescribed to reduce the skin. The data were analyzed and solutions proposed from a Production Center of Excellence (PCoE) located more than 2,700 miles away.

Closer to home, PCoE engineers helped a Texas-based operator save a well from abandonment. The operator had decided to shut in one of its under-performing wells, but artificial lift and production experts at the PCoE were able to remotely conduct a quick well analysis simply by shutting off the pump and restarting it to create a pressure transient. Upon analysis of the pressure data captured by the monitoring and control system (see Figure 1) and monitored at the PCoE, the engineers diagnosed near-wellbore formation damage with skin effect of +35 (see Figure 2).

A Nodal analysis was performed to predict the potential incremental production if the skin were removed and calculated the net present value of the improvement versus the cost of the remedial treatment (Figure 3). Encouraged by the...
results, the operator stimulated the well using hydraulic fracturing. As a result, production improved from about 811-bpd to 2,290-bpd with incremental oil production of 80-bod. After spending $75,000 to treat the well, the operator realized increased annual revenue of $2 million (based on $70/bbl oil).

**Plug n’ Play**

While pump performance sensors are built into the pumps and motors, a gauge package is in a separate plug n’ play module that can be installed or removed quickly, as desired. Options allow pressure and temperature readings to be acquired and transmitted from three different locations—at the pump intake, the pump discharge and at the point below the ESP motor. Using a standardized system providing systematic monitoring and analysis, technology can leverage the shortage of trained equipment operators and production engineers.

Operating by exception benefits both operators and service company personnel who can effectively supervise entire assets with minimal staff. Using a centralized facility allows concentration of expertise. Each problem is assigned to an experienced engineer for diagnosis and disposition, collaboration with the operators’ engineers and development of a solution. Alternative solutions can be simulated and game-played using the latest economic and risk analysis programs to facilitate decision-making and minimize downtime. In most cases, remedial steps can be executed remotely using the same communications network that delivered the data. When an intervention is needed, detailed instructions can be relayed to the field crews who will perform the work.

One system offshore West Africa is located on a satellite platform, miles from the production facility. The well is so remote that lead time to contract a workover rig for pump replacement is between 6 and 12 months. Accordingly, the well is equipped with two ESPs in tandem with automatic valves and switches that enable the spare pump to be remotely started within minutes of alerts that the operating pump has (or is about to) shut down. When the switchover is made, an alarm is automatically sent to the production facility, so no production is lost while a rig is mobilized to perform a workover. The only deferred production occurs during the short interval while the ESPs are actually pulled and replaced. Since the operating pump is switched off before it destroys itself, it can usually be repaired and placed back in service the next time a switchover is made.

**Conclusion**

The use of integral sensors and telemetry has revolutionized the artificial lift business by allowing vast numbers of remotely-located wells to be efficiently and effectively monitored by a dedicated team of experts. The efficiency of scale afforded by automation and telemetry, coupled with powerful diagnosis and analysis tools, makes advanced lifting services practical for everyone. Valuable equipment is given longer life by maintaining operating efficiency and protecting it from self destruction. Individual well and reservoir production are optimized. Onsite, the downhole monitoring systems are capable of enabling diagnostic downhole evaluation to reveal problems with wells or with the entire reservoir. Even when an intervention is the only solution, it can be planned so downtime and deferred production are minimized. By taking advantage of all the options provided by downhole monitoring systems and remote diagnostics and optimization services, equipment can be saved, downtime can be minimized and production optimization realized.

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