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What's new in artificial lift?

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Pump-assisted	Fluid-assisted	Flow enhancement
Beam/rod pump systems	Gas lift	Plunger lift systems
Linear lift pumps	Hydraulic jet pumps	Velocity strings
Hydraulic piston pumps	–	Foam lift
Electric submersible pumps (ESPs)	–	Compression
Progressive cavity pumps (PCPs)	–	–

Table 1. Categories and types of artificial lift systems

There are probably as many ways to classify artificial lift systems as there are production engineers in the world. As a point of reference, we like to look back each year to **Table 1,** which we first published in this feature in May 2013. As indicated, we think it makes some sense to organize artificial lift systems into three categories: 1) pump-assisted systems; 2) fluid-assisted systems; and 3) flow enhancement techniques. Within these three categories, there are basically 11 types of lift technologies. In each category, there also exist unconventional or emerging technology types of lift.

BEAM/ROD LIFT DEVELOPMENTS

Although electric submersible pump (ESP) systems have surpassed beam/rod pumping as the fastest-growing technology in the artificial lift market, the latter is still the most common form of artificial lift found in oil fields today. The basic beam/rod pump system consists of three components: a surface beam pump, a connecting rod string, and a downhole plunger pump.

A new horse in town. Liberty Lift Solutions is one of the newest innovators in the artificial lift world, offering a complete line of conventional and enhanced geometry, beam pumping units.

Fig. 1. Liberty Lift conventional beam pumping unit.

The Liberty HE (high-efficiency) conventional pumping unit (**Fig. 1**) is far from conventional, based on the manufacturer's claims of performance and ruggedness. The Liberty HE can be operated in either clockwise or counterclockwise rotation. When operated in the clockwise direction, the HE design devotes 186° of crank rotation to the upstroke, instead of the usual 180° with many other conventional units. This offers operational advantages. The longer upstroke duration adds more time for pump fillage, allowing the unit to perform more work than comparably sized conventional units. The HE design provides a perfect balance between the versatility of conventional geometry and the focused operation of special geometry.

The company's EG (enhanced geometry) pumping unit's design maximizes efficiency and presents the user with a high-performance, durable and reliable unit. It is designed to achieve the optimum mechanical efficiency during the pumping cycle's upstroke, devoting 192° of crank rotation when fluid is being lifted, and the pump is being filled. A slower upstroke reduces acceleration, lowering sucker rod forces and peak torque requirements.

The EG unit's larger polished rod load ranges can be handled without overloading the reducer. Contributing to this net torque reduction is the optimal counterbalance phasing. The optimized EG geometry and phase angle produce the maximum possible, permissible load range. More lifting and less horsepower equals "enhanced geometry." In fact, permissible load in the upstroke is the maximum load that can be applied to the polished rod at any given crank position without causing torque overload. Permissible load in the downstroke is the minimum load that can applied to the polished rod, to prevent overloading when lifting counterbalance. Thus, permissible load range is a banded region that is the difference between the minimum permissible load during upstroke and the maximum permissible load during downstroke, which can be applied to a pumping unit without creating a torque overload.

Both HE and EG structure bearings are high-capacity, energy-efficient anti-friction bearings, designed to provide trouble-free operation. The saddle bearings and equalizer bearing are rugged, double-row, tapered-roller bearings, requiring no operational adjustments. They can be lubricated from ground level. The wrist pin assemblies are designed using heavy-duty, double-row, and self-aligning, spherical roller bearings. As an added feature, bearings are shouldered on the wrist pin for easy maintenance. All structure bearings exceed API design requirements.

Company designed and manufactured gear reducers provide continuous trouble-free operation and exceed all API requirements. The involute tooth gear form is a highly efficient, rugged and quiet means to transfer power. The course pitch design also assures that the gear reducer has the ability to withstand operational load fluctuations.

All gears and pinions are double-helical types and manufactured using a precision hobbing process, to assure a balanced loading and quiet operation. The pinions and low-speed shaft are made from quenched and tempered alloy steel, to promote the reducer's long life. The high-speed gears and low-speed gear are made from ductile iron castings, then rough-machined and normalized to enhance durability. The bearings in the gear reducers are all oversized anti-friction bearings. This energy-efficient design can be rotated easily by hand.

The gear reducer oiling system supplies ample lubrication to every reducer bearing, even at operating speeds of one stroke/min. in either direction of rotation. The reducer's exterior case is constructed of gray cast iron and is of the centerline split type.

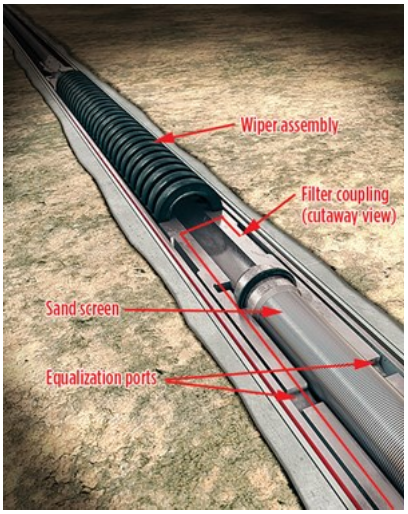


Fig. 2. Cutaway diagram of Weatherford's downhole Sand-Tolerant Pump (STP), showing a sand exclusion screen below the wiper assembly.

The structure designs of the HE and EG units exceed all API design requirements, and are licensed to carry the API monogram.

Extend pump run time in sandy, rod-pumped wells. When pumping sand-laden wells with reciprocating rod-lift systems, produced fluids contain abrasives that can cause unacceptable levels of equipment wear. This often shortens downhole rod pump life, reduces production rates and increases operating costs.

Based on ongoing tests, Weatherford's downhole Sand-Tolerant Pump (STP) works more than four times longer in these conditions than conventional rod pumps, because the patented design lubricates the plunger/barrel interface without letting sand enter this critical area. By means of specialized screens that stop sand, and a unique design that cleans the screens on every stroke, the sand is cleared from the pump and produced to the surface, **Fig. 2.**

The outside of the wiper assembly creates a barrier that keeps sand out of the barrel/plunger interface by continuously pushing the sand upward, and the assembly's internal components prevent sand from falling back into the plunger. Because the wipers also prevent sandy, produced fluid from entering between the plunger and barrel, this critical area is no longer lubricated by the fluid above the pump. The filter coupling overcomes this potential problem, by enabling clean, produced fluid to pass through the equalization ports, and lubricate the plunger/barrel interface as it moves up and down.

The filter coupling houses the internal screen that prevents sand from escaping through the equalizer ports with the fluid. Because the filters move with the plunger, the sweeping action of the fluid on the downstroke cleans the filters and keeps the sand suspended within the production fluid. The sand-laden fluid is then produced through the center of the plunger to the surface.

The STP fits most API pump sizes and performs effectively in a variety of well conditions. It runs in temperatures up to 360°F and depths down to 9,000 ft. By extending the run life of the downhole pump—the most sand-sensitive component of a reciprocating rod-lift system—the time between failures of the entire system is also lengthened.

Working in conjunction with a major operator in California, Weatherford studied 56 problem wells, where data was collected during two previous pump runs using conventional pumps in a sand-producing reservoir. Because of sand issues, none of these wells reached 365 days of run life.

Installing the STP pumps increased run time by an average 450%. Of the 56 pumps included in the study, 30 continued to run without intervention at the end of the testing period. Of those 30, the longest recorded STP run time was 584 days, compared to an average of 174 days using conventional pumps in that same well.

When the STP units were pulled, failures typically were not related to erosion and wear. After cleaning and inspection, most STP parts had minimal damage and were reused. This resulted in significant cost savings, compared to the usual equipment replacement costs incurred from sand-related failures in conventional rod pumps.

LINEAR LIFT PUMP DEVELOPMENTS

For counterbalance, beam pumping units employ large weights placed opposite the sucker rod string. There are several variations to this method:

- Beam-balanced
- Crank-balanced
- Alternative or enhanced geometries with varying forms of counterbalance.

Fig. 3. Several CAMLIFT 40-192 linear lift systems employing Cameron's new counterbalance system.

Common drawbacks to all of these systems are the large, heavy weights that create inertia, and the difficulty to move them, to adjust the counterbalance.

These systems work best with a fixed velocity profile, as additional energy is required to manipulate the inertia and affect the velocity throughout the cycle. Velocity profiles are adjusted, using Variable Frequency Drives (VFDs) that add capital cost. When adjustments to the velocity profile are required (such as in the case of slow falling rods), a significant amount of energy is wasted, which increases operating costs. Adjusting the counterbalance on beam units to match the load profile of the well is often difficult and contributes to downtime. In addition, rotating weights can pose a significant safety hazard on a well or pad site.

Linear lift units use a variety of counterbalance technologies:

- Weatherford Rotoflex—counter-stacked weights
- Tundra Dynapump—single vessel nitrogen over oil

- Weatherford VSH2—piston accumulator with nitrogen bottles
- NOV Morlift—nitrogen accumulators with dedicated counterbalance cylinders
- Unico LRP—potential electric regeneration.

New, innovative counterbalance for linear lift pumping unit. An innovative counterbalance system has been introduced recently: Cameron's CAMLIFT 40-192 system, **Fig. 3.** This patented counterbalance system employs a master and lift cylinder hydraulic arrangement. The weight of the rod string is transferred efficiently to a nitrogen-over-hydraulic accumulator bank. The stored energy is employed, as needed, on the upstroke to manage the velocity profile. The hydraulic arrangement allows the prime mover (gas/electric motor) to run at a constant load, increasing its efficiency and reliability.

Fig. 4. Tundra's DynaPump SSi linear lift unit.

Eliminating the weights and the resulting inertia allows for simple and efficient manipulation of the velocity profile. This allows operators to easily match the pumping unit operation to the downhole conditions. This can be used to improve pump inflow, match rod fall speeds, reduce cyclic stress on the rod string, reduce peak velocity and rod tubing wear. The hydraulic arrangement also allows for easy adjustment of the counterbalance settings to match the changing rod string loads, as the fluid level changes.

The CAMLIFT 40-192 unit can lift 40,000 lb of peak polish rod load, with a maximum 192-in. stroke length. This is comparable to a 912 beam pumping unit, but with a significantly lower profile and surface footprint. The unit's speed range of one to six strokes per minute offers a very large production range, which allows it to follow steep decline rates (often reducing changes in surface equipment throughout the life of the well).

Sure Stroke Intelligent (SSi) lift system. Tundra Process Solutions Ltd. acquired the assets of DynaPump Inc., the California-based manufacturer that had supplied over 700 artificial lift systems, worldwide. Tundra is the official manufacturer of the well pumping solution called the Sure Stroke Intelligent (SSi) lift system, **Fig. 4.**

These units are surface-mounted lift systems that use state-of-the-art electronics, hydraulics and computer monitoring systems to lift fluids in an efficient manner from both deep and shallow wells.

The long, slow stroke of the SSi produces fewer pumping cycles, less rod and tubing wear, and increased downhole pump efficiency. This can increase production rates while minimizing well servicing frequencies. Tundra claims this artificial lift system weighs less, is more cost-effective, more energy-efficient, and has greater lifting capacities when compared to conventional beam pumping systems.

Fig. 5. The Zedi SilverJack linear lift system.

"The different-sized pumping and power units are matched to meet the specifications of each well. The SSi is no longer a niche product, and can be used to advantage in most well applications," says Paul Tonks, Logistics manager at Tundra.

In addition to the company's SSi lift system, Tundra also offers the SCADA-Lynxs monitoring system, which allows operators to track the performance of the SSi system, as well as how the well is performing in real time from the convenience of a remote computer or smart phone.

Remote detection and resolution of common rod pumping issues. The Zedi SilverJack linear lift system (**Fig. 5**) is a combination of a surface hydraulic lift solution with an integrated controller, combined with a web-based data collection/management/control system called ZediAccess, **Fig. 6.**The control system provides the capability to remotely detect and resolve many common problems encountered with conventional downhole rod pumping equipment.

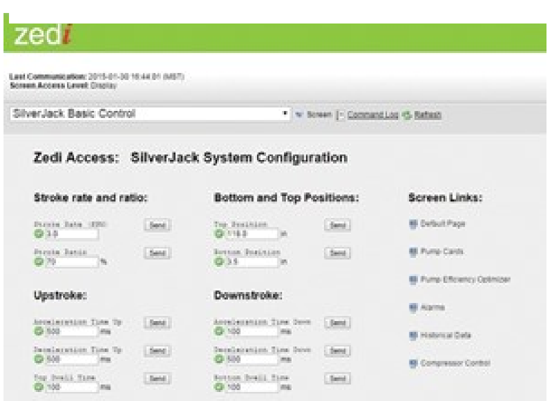


Fig. 6. Basic Control screen/user interface used to configure movement settings.

With precise monitoring and trending of rod loads, position, velocity and other key operating parameters, the SilverJack system auto-detects and notifies operations and production team members of issues with rod pumping quickly (in as little as 15 min.).

Early problem detection and notification is the first step in avoiding costly downtime, but quick problem resolution is just as important. With the SilverJack's unique capabilities to support remote adjustment of all aspects of rod string movement (i.e., stroke rate, stroke length, up/down stroke ratio, acceleration time up/down, deceleration time up/down, and top/bottom dwell times), many common problems can be addressed without the need to travel to the production site, to ensure optimal performance.

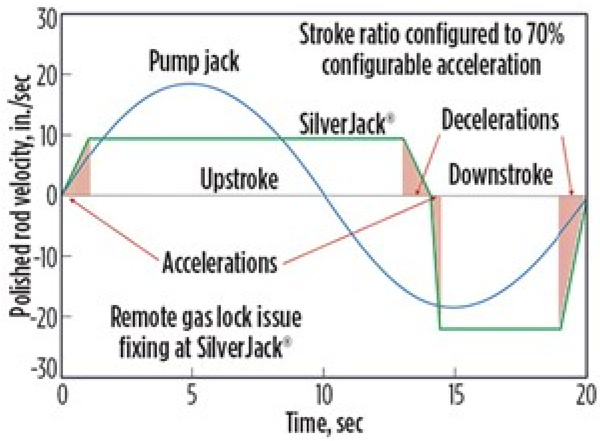


Fig. 7. SilverJack hydraulic velocity vs. time diagram used in correcting gas lock issue.

Examples of rod pumping issues that can be detected remotely and solved include: gas lock, traveling valve seating issues and debris in downhole pumps. **Figure 7** shows the SilverJack rod-string adjustments used to address gas lock issues. By increasing the downstroke acceleration and velocity, the pressure differential on the traveling valve can often be increased enough to open the valve and allow the gas to escape. By using the system, operators have achieved a 90%+ success rate in addressing such issues. This has resulted in significant cost savings through reduced downtime, less site visits and avoided workovers.

HYDRAULIC PISTON PUMP DEVELOPMENTS

Dewatering gas wells with hydraulic piston pumps continues to evolve. Hydraulic dewatering is a viable solution at the point in a well's life, where added energy is required to lift the fluid column to the surface, so natural gas can continue to flow.

A "rod-less" rod pump. Dover Artificial Lift has designed, manufactured, tested and field-proven a new product that effectively dewaters gas wells, and produces low volume and/or declining oil wells that are nearing the end of their production lives. This hydraulic reciprocating piston pump (the "R. Pump") works much like a rod pump. Except, it employs no sucker rods and demonstrates an improvement over a traditional rod pump in its ability to perform in low-production, low-power fluid and low-bottomhole pressure environments. These enhanced capabilities result in lower horsepower, and provide production companies a means to dewater gas wells and maximize the ends of their oil wells' lives.

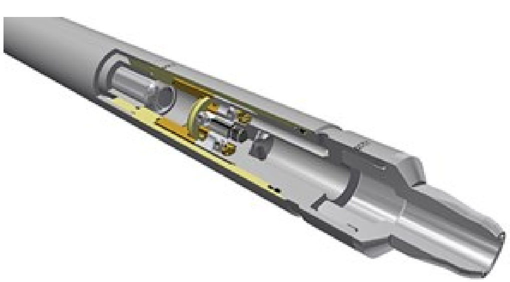


Fig. 8. Dover's downhole, hydraulic-reciprocating piston pump.

In addition to low-production, low-power fluid and low-bottomhole pressure operating possibilities, the R. Pump can successfully operate in deviated wells, since it has no rods to bend or break. It also can operate successfully in gas wells, because the reciprocating pump action will not lock-up like a rod pump will, when gas invades. Moreover, the R. Pump requires a much smaller surface footprint, as one hydraulic surface pump can power multiple downhole R. Pumps, **Fig. 8.** Most important in an economic climate, where producers and operators are looking for cost savings at every turn, this hydraulic reciprocating piston pump does not need a workover rig in the event of an inspection or repair. Its flow simply can be reversed from the surface to pump the downhole pump out of the well.

The redesigned, single-acting pump uses a pre-existing design of an engine valve assembly, and uses the concept of a rod pump end for the pumping end. This design allows for a much longer stroke and larger pump end capacity. The advantages of the design allow the piston pump to reciprocate at a lower rate, while keeping the production volume the same. The design also allows for slowing the pump speed more than a typical piston pump, to produce volumes as low as 25 bopd, if desired.

The downhole pump can be installed on conventional or parallel strings. It offers a wide range in speed options (5 to 65 spm), production capacities (10 to 250 bopd), and has a longer stroke length (24-in.).

These key design features result in fewer parts to repair and replace. Additionally, if repairs are necessary, it results in a faster, cheaper and easier turnaround. The target application of the pump is a flowrate of 10 to 200 bopd, a depth of 5,000 ft to 18,000 ft, a water cut of 0% to 50%, and a maximum GLR of 200:1. The pump can run as low as 5 spm to10 spm, can operate in as little as 10 bopd, and is customizable per well, because the P/E ratio and production capabilities can be reconfigured by adjusting only two parts.

HYDRAULIC JET PUMP DEVELOPMENTS

Fig. 9. Ultra-Flo system with a T-Series diaphragm pump (inset).

Recent design developments by JJ-Tech (with distribution and service support from Liberty Lift Solutions) combine the highly versatile Select-Jet pump with a virtually maintenance-free Hydra-Cell T-series diaphragm pump (from Wanner Engineering) into the Ultra-Flo system (U.S. Patent# 7,255,175), **Fig. 9.** The combined system makes the use of hydraulic jet pumps more attractive, since the surface pumps are not plagued by maintenance issues associated with conventional “packed” plunger pumps.

The Select-Jet pump allows the operator to run in normal or reverse flow, without having to utilize a “sliding sleeve” and, most importantly, without having to pull the completion. The Select-Jet BHA is made from 17-4 PH stainless steel, to ensure maximum longevity. It also allows the operator to use downhole pressure gauges (pressure bombs) without requiring a slick-line to set/pull gauges. The pressure/temperature recorder can be hydraulically set into, and retrieved from, the wellbore.

Hydraulic jet pumps have many positive operating benefits:

- No moving downhole parts, making production of sand/solids possible
- Work great in highly deviated/horizontal wellbores
- Tubulars can be treated continuously with corrosion and scale inhibitors
- Software optimization is easy, to maximize surface horsepower
- Highly scalable production rates are easily achieved
- Jet pump is hydraulically retrievable to the surface.

JJ-Tech also offers a line of tubing-deployed jet pumps that, according to the manufacturer, have the largest flow passages in the industry. They are reported to be ideal for high-volume wells and frac fluid recovery.

The company's slim-hole jet pumps work well for gas well deliquification. Tubing options can be as small as a 1-in. integral joint inside 2 3/8-in. production tubing. These jet pumps are often run at 90° of inclination, far lower than one would run a conventional rod pump.

The Hydra-Cell seal-less pump design eliminates VOC emissions, packing maintenance and plunger wear. It requires less routine maintenance and has the ability to handle corrosive and abrasive fluids. The pump can operate with a closed or blocked suction line and run dry indefinitely without damage, avoiding downtime and repair costs. Low NPSH requirements allow it to operate continuously with a vacuum inlet condition, so positive suction pressure is not necessary. This eliminates the need for a charge pump to the suction. The T80 series pumps are available in 3,000-, 3,500- and 5,000-psi models.

AUTOMATION AND CONTROL EFFICIENCIES

The costs to power artificial lift systems can be significant, and overtime can represent the highest cumulative cost of pumping a well. Additionally, artificial lift control systems have become increasingly important to operators, since production downtime for any reason is very costly.

Emerson variable-speed solutions enhance beam pumps. Emerson Industrial Automation's latest solutions, such as the Powerdrive FX four-quadrant drive, in combination with an LSRPM synchronous magnet-type motor from the company's Dyneo range, are now delivering advantages to increasing numbers of wells using beam pumps (RRP or reciprocating rod pumps).

Fig. 10. Emerson's Powerdrive FX four-quadrant VSD (left), and their LSRPM synchronous magnet-type motor (right) enhance rod pump operations.

Numerous concerns over fixed-speed, reciprocating rod pumps are driving demand for variable-speed solutions. These include pump-off, which will likely occur if production is too high (due to incorrect pulley-belt ratio). Secondly, pulley-belt ratio adjustment is required frequently in new wells.

Other concerns over fixed-speed pumping include the limitation of monitoring possibilities and potential difficulties in detecting fluid pound. Furthermore, too many motors on the same electric network can cause a lagging power factor, driving the need for capacitor banks.

In contrast, variable speed drive (VSD) technology allows pumping speed to be adjusted to field requirements, thus avoiding field work and the interruption of production. Further advantages include the ability to correct the oil field's power factor without the need for capacitor banks, while VSDs also provide soft starting, torque limitation and constant speed (reducing mechanical stress on the gearbox and rod).

Because RRPs have a particular operating cycle, whereby power is actually produced 15% of the time, in the past this power had to be dissipated through bulky braking resistors. However, using Emerson's patented, compact, four-quadrant, C-Light Powerdrive FX VSD (**Fig. 10,** left), these issues are negated. For instance, there is no need for additional resistors—the power generated is fed back naturally to the power supply like with a line contactor in fixed speed. What's more, harmonics are 25%, lower than a conventional six-pulse solution (independent of the load), while a better power factor means that Powerdrive FX also offers significantly lower line current.

Other advantages of this VSD include easy installation and a rugged design featuring tropicalized boards and a resin-treated line choke. In addition, due to remote access capability, it eliminates the need for technicians to visit the site to retrieve well data, set speeds and reset any faults.

Full production optimization will rely upon pairing the VSD with Emerson's Dyneo LSRPM synchronous magnet-type motor,**Fig. 10** (right). Over a cycle, the torque profile of an RRP averages 50% of the nominal torque of the motor. In comparison with an induction motor, according to the manufacturer, the higher efficiency of the Dyneo LSRPM over a wide speed and load range will lead to significantly reduced electricity consumption. Other benefits include its advanced design, which saves on maintenance through longer bearing life and reduced lubrication intervals. Furthermore, not only is this motor smaller and lighter than a standard induction motor, it is also proven technology that does not require servicing any differently.

Fig. 11. Wireless Load Cell from Bright Automation (right) with the companion receiving module (left).

The manufacturer's tests indicate that the combination of the Powerdrive FX VSD and the LSRPM motor offers up to 20% in energy savings, reducing considerably the total cost of ownership, compared with a traditional six-pulse drive and induction motor.

Wireless Load Cell reduces operational costs. Advances in automation have long rendered significant benefits in oil production, and that trend continues today, as operators search for various ways to improve efficiencies and cut costs. New wireless automation technology is one area that is gaining significant momentum, based on the fact that it: 1) saves on labor and equipment costs; 2) significantly reduces production downtime; 3) provides easy set-up; and 4) allows for relatively easy maintenance. All of these factors can add to a more efficient operation and reduced maintenance requirements.

A prime example of new automation technology is the Wireless Load Cell from Bright Automation. Based on its wireless design, this patent-pending device requires minimal wiring, and combined with the unit's u-shaped design, provides for easy installation, repair and maintenance. The Bright load cell uses a 2.4-GHz, wireless digital communication protocol to transmit data from the cell to the receiving unit, **Fig. 11.** The receiving module output generates a standard 4-20mA or 0-10mV signal through a standard RS232 signal in transmitting real-time load data. Based on its standard output, this load cell can readily replace a conventional load cell.

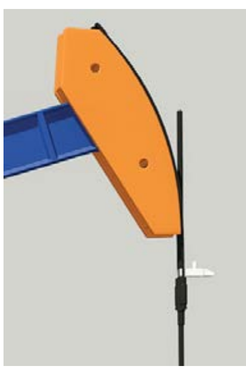


Fig. 12. Bright's Wireless Load Cell mounted at the head of a beam/rod pump.

Eliminating the cable connection from the load cell to the control unit adds to the operational reliability of this system, because there is no cable that can be disconnected or cause damage to the polished rod. Alarms and shutdowns can be reduced significantly, because standard cable issues are eliminated. In addition to providing for an easily installed and reliable load cell, this wireless design also reduces the potential for safety issues, since the trip hazard presented by a dangling cable is also eliminated.

From a pricing perspective, this wireless load cell actually costs less than having to replace cables on a traditional load cell. Further, by going wireless, operators do not have to worry about the subsequent cost of changing out future cables.

This wireless load cell can be added easily to existing pumps, (**Fig. 12**) and with a full charge, the unit's built-in solar-powered battery provides reliable service for up to 30 days without any exposure to sunlight.

New wireless power measurement equipment. Echometer Company has developed new wireless, high-frequency, motor power-current-voltage measurement equipment to acquire and analyze the electrical and mechanical performance of sucker rod pumping systems. PC-based TAM software receives and analyzes pumping system data to determine power usage, power generation, pumping unit balance, gear box upstroke and downstroke torques, motor loadings, electrical surface system efficiency, overall electrical system efficiency and power line loss. Line loss is a new analysis performed to analyze the power loss between the transformer bank and the pumping unit motor.

One of the objectives of the new wireless power measurement equipment is to minimize the risk of electrical shock by eliminating the need for production operators to open the switch box. The power sensors are mounted permanently in the electrical box, with a water-tight connection on the side of the electrical box for attachment of a small plug-in radio for wireless communication to a portable PC base station, **Fig. 13**

Fig. 13. Echometer's new wireless power measurement system.

Power measurements are instrumental in minimizing operating costs, since they pinpoint wells that are not operating efficiently. When system efficiency drops below a certain threshold (for example 40%), it is an indication that the pumping system should be analyzed in detail to identify and remove the cause of the inefficiency.

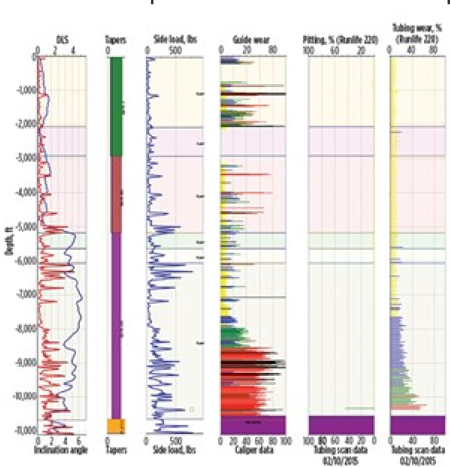
Pumping unit counterbalancing has always been an integral part of those field activities designed to reduce operating costs. Accurate balancing of beam pumping systems is greatly simplified by the acquisition of instantaneous electrical power used by the prime mover and converted to torque. In a beam pumping system, the instantaneous torque at the gearbox can be calculated from direct real-time measurement of the power and the rotation speed. Software calculates the necessary counter-balance movement required to balance the unit based on operator inputs.

A possible source of inefficiency and additional operating cost is an improperly sized electrical line from the transformer bank to the switch box. Detailed analysis of the amperage and voltage during start-up and normal steady state operation of the pump allows estimation of the power losses occurring in the transmission line from the transformer to the motor. This calculation then can be used to evaluate the need and economic benefits of upgrading the power line size for the well (or wells) in question or for designing a correct line size in future installations.

In wells where this permanent connector is not installed, a portable wireless power probe (with two current sensors and three voltage probes) is connected to the internal wiring in the switch box. The producer can reduce electrical costs with use of the power probes to locate and improve inefficiently producing wells.

OTHER DEVELOPMENTS

To control production costs and keep rod-pump wells performing up to expectations, proactive maintenance is increasingly important.



Value-added services maximize well performance. Asset protection is critical, as highly corrosive environments and wear caused by contact between sucker rods and production tubing during normal operation can damage the production string on equipment. Through National Oilwell Varco (NOV) solutions of wear mitigation, corrosion control (**Fig. 14**), inspection programs and Rod Guide Advisory Program (RGAP), the life of the production string can be extended.

Fig. 14. Well profiles show the rate of corrosion (left bars) and wall loss (right bars), by joint, at precise depths.

With NOV's sucker rod coating solutions, advanced technology deploys stainless steel to extend rod string life and mitigate the problems associated with operating in highly corrosive conditions. TK Coating solutions increase used rod inspection recovery rate and is excellent for high-volume, hard to treat wells. The coating also reduces downtime and rod-pulling, due to failure, and protects guided rods from corrosions attack due to turbulent flow.

Tube-Kote internal plastic coatings are engineered thermoplastics, designed to address the operating needs of every type of oilfield environment. These coatings are based on thermoset and thermoplastic polymers, each selected for specific chemical and mechanical properties, and the ability to deliver unparalleled performance in various corrosive environments.

Additionally, in an engineered sucker rod string proper rod guide design, placement and material selection are critical for obtaining the best overall performance. Using NOV's RGAP (**Fig. 15**), wellbore deviations, dynamometer readings, workover histories, well operating conditions,completion information and production data; NOV selects the proper guide designs, material and spacing for each well. NOV can monitor and track operators' individual well performance and recommend the appropriate rod guide design, material, spacing and auxiliary equipment, for both beam and progressing cavity pump applications.

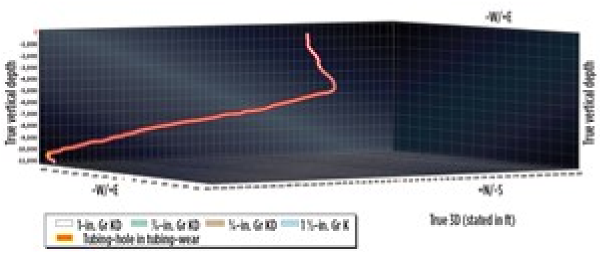


Fig. 15. 3D representation of a sample well created by the latest version of RGAP.

Originated in the 1990s, the company's WellChek Inspection System was designed to navigate used API tubing, as it was pulled from the well during workover operations. This inspection service, part of a complete diagnostic system offered by NOV, offers operators a summary of tubing strings, as they are being pulled.

Whether using beam pumping units or progressing cavity downhole pumps, NOV offers tubing wear solutions, including tubing rotators and rod rotators, to improve tubing and rod life by creating a 360° even wear to the tubing and rods. Among other benefits provided by these tools are decreased workover costs and reduced downtime.

Update on capillary injection tubing anchor. Many operators rely on capillary injection systems to deliver chemicals that fight corrosion and deposits downhole, because targeted chemical applications can significantly extend the production interval between workovers and protect the economic viability of the well. For real-time monitoring of rod-pump systems, which has gained growing acceptance in recent years, downhole gauges have provided valuable insight.

Conventional rod-pump tubing anchors require up to 12 rotations to set. This can limit capillary strings and downhole gauge cables to installation only above the tubing anchor, because the risk of crimping or breaking these lines while deploying the anchor is unacceptably high. As a result, the pump and the tubing below the anchor remain exposed to untreated wellbore fluids, and the area near the pump inlet is inaccessible to gauges.

Fig. 16. Weatherford's capillary injection tubing anchor provides an improved delivery for treating chemicals.

Weatherford's capillary injection tubing anchor (**Fig. 16**) (featured in this series in May 2013) eliminates the multiple turns required to set the anchor. It sets and unsets in just one-quarter of a full turn. This provides unprecedented access to the rod-pump inlet and significantly lowers the risk of damaging or breaking externally banded lines during anchor deployment. Depending on the application, a capillary line or gauge cable passes through the anchor via a bypass channel, which accommodates either 1/4-in. or 3/8-in. lines.

For downhole sensing applications, the tubing anchor has been deployed successfully, improving real-time monitoring and optimizing lift-system performance. The anchor's bypass channel enables tubing-encased cables to be deployed below the anchor and tied into a temperature and pressure gauge at the pump intake. To save additional time and cost, gauge cables can be installed by the same crew that installs capillary lines at the rig site, instead of requiring a separate crew to accomplish this task.

To control corrosion and deposits, the capillary injection tubing anchor enables the capillary line to deliver treatment chemicals directly to the downhole pump inlet. Because 100% of the chemicals are delivered where they are needed, on average 30% to 40% less chemicals are required to keep the well producing at optimum levels. This can decrease operating costs and downtime by minimizing expensive, time-consuming rod and tubing replacements.

For example, an operator in the Permian basin found that chemical injection of five quarts per well, per day, was insufficient to prevent corrosion-induced failure in newly completed wells, particularly in lower sections below the tubing anchor. Every one to two weeks, wells were shut in for at least three days to repair or replace corroded equipment, at an average cost of more than $25,000 per pull. The operator was forced to make a minimum of two pulls per year on each well in the first year of operation, at an average annual operational cost of more than $95,000 per well.

Since replacing the conventional tubing anchors with these new quarter-turn tubing anchors, the wells have been running for more than one year with no pulls. By delivering less expensive, yet more effective, chemical treatments with pinpoint accuracy, the operator reduced workover frequency and minimized chemical costs, which decreased average annual operational costs for each well by nearly $77,000 in the first year alone.

A complete well flow management portfolio. According to Schlumberger, as part of their strategy to better integrate its production solutions, the company has brought together leading providers of rod and beam pumps, acquiring 16 companies throughout the major North American basins over the last several months. Schlumberger now offers a complete suite of artificial lift products for the life of the well, including electric submersible pumps, gas lift, horizontal surface pumps, sucker rod pumps, progressing cavity pumps, and production design and optimization software.

The company's sucker rod pump solutions now include an extensive range of beam-balanced, low-profile, improved-geometry, and conventional pumping units. In addition, the company now offers hydraulic stroking units, which have a preventive leak design and long stroke lengths that make these units an ideal fit for many applications, including gassy, horizontal wells and shale plays.

Schlumberger also has a wide variety of downhole components, including sucker rods, polished rods, and downhole pumps. Through its established distribution network, the company can quickly deliver a replacement part, if an original component has worn out, or if downhole conditions change.

With these latest acquisitions, the company's comprehensive portfolio now includes artificial lift products for all applications and production volumes for a complete engineered production solution. According to a company spokesperson, Schlumberger's goals are to maximize production, improve reliability downhole, and reduce downtime with comprehensive lift packages tailored to each customer's unique operational challenges.