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INTELLIGENT WELLS AND FIELDS

What's new in artificial lift

NOCs growing and evolving

Deepwater drilling advances



PRODUCTION TECHNOLOGY

What's new in artificial lift

Recent developments are introduced in beam/rod pumping, electrical submersible pumping, gas lift, gas well dewatering and artificial lift monitoring.

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Presented here are 18 recent technology developments in artificial lift equipment and software associated with artificial lift.

New offerings related to beam and rod pumping include an improved downhole separator for placement in the near-vertical section of a horizontal well producing gas and some liquids. An improvement in materials is discussed for a device to prevent pump sanding, as well as a pump designed for sandy wells, and an adjustable threaded polished rod is presented that allows for safer and simpler spacing of the downhole sucker rod pump.

Among ESP-related advances, a dual ESP system provides either a backup in the case of primary pump failure or an improved solution for multizone production. Enhanced modeling software is presented that assists in the design of ESP and gas lift systems. A number of improvements in one supplier's pump stage portfolio are discussed, as well as an elevated-temperature ESP for SAGD applications and an ESP deployment system that allows pulling and replacement without a workover rig.

Gas lift-related advances discussed are a valve plug that dissolves in saltwater, to eliminate the need to remove dummy valves in new gas lift systems, and two new check systems for 1½-in.-OD gas lift valves and for use on a recently introduced mandrel.

Within the topic of gas well dewatering, a new instrumented plunger determines location by sensing the collar lo-

cations in the tubing along with pressure and temperature. Also, a three-in-one plunger combines increased efficiency, pressure actuation for sandy conditions, and improved lubrication. Also presented is a high-pressure, cold-weather lubricator developed to comply with the same standards and requirements as other wellhead components.

To monitor artificial lift system performance, a proprietary interpretation technique provides real-time flowrate without the need to retrofit additional hardware in the field, with the exception of downhole ESP gauges and SCADA. Also discussed is a flexible ESP monitoring, surveillance and production optimization tool. Another company has combined computerized analysis of dynamometer records with powerful portable computers, advanced modeling software and wireless data acquisition to allow visualization of rod pump operation in real time.

Finally, a novel pumping system is presented that combines the advantages of beam pumping and ESP systems.

BEAM/ROD PUMPING

High oil prices relative to natural gas have led to a resurgence of activity in the Permian basin and other oil producing regions where beam and rod pumping are common forms of artificial lift. This resurgence has led to heightened demand for products related to beam and rod pumping.

Downhole gas separator. Gas interference has long been a hindrance to maximum production in the region, leading to downhole equipment failures. The Don-Nan Gas Separator, developed by Midland, Texas-based Don-Nan Pump & Supply, is being used effectively to remove this troublesome gas from the wellstream in Permian basin wells, as well as in oil-producing regions of southeast New Mexico and the US and Canadian Rockies.

Produced in several lengths, tubing sizes and materials to meet varying well conditions, the gas separator is positioned

within the tubing string directly above the tubing anchor catcher and rotational packer. The presence of a pack-off rubber ensures that all formation fluids pass through the gas separator before entering the pump intake. The gas separator is designed to break the gas out of the fluid and allow it to travel upward faster than the velocity of the liquids being drawn into the pump. It prevents the free gas from reaching the pump intake, thereby reducing gas interference and gas lock and improving pump efficiency. By lowering the fluid level in the casing, the separator also creates an environment conducive to continuous chemical treatment for maintaining a corrosion-free well.

Formation fluid travels through the tubing string and reaches the ported coupling of the separator, **Fig. 1**. The fluid passes through the ported coupling and enters the annular space between the inner flow tubing and the outer tubing.

Fig. 1. Don-Nan Gas Separator schematic.

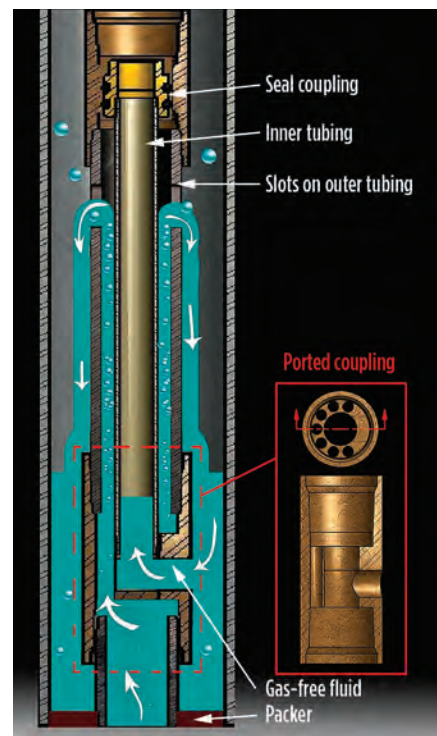
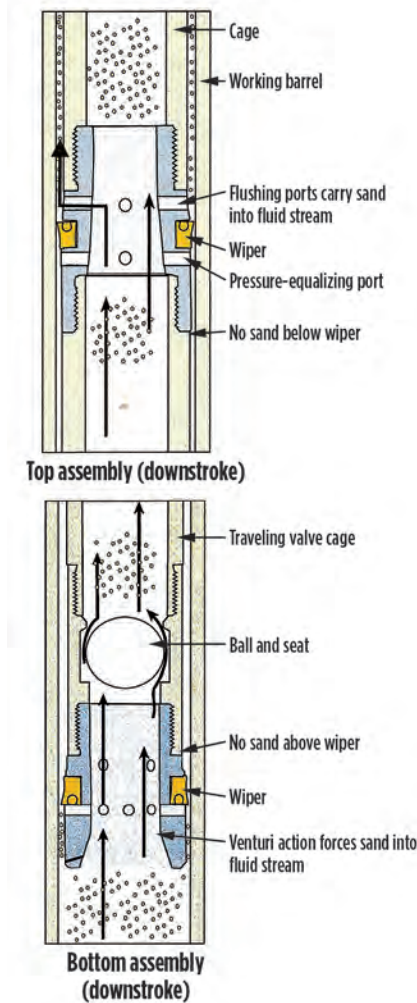


Fig. 2. Kajon Oil Tools Sandbuster schematic.



Once this annular space is filled with fluid, it passes through the four slots of the outer tubing and falls back into the outer tubing/casing annulus, settling on the packer. Within this flowpath, the fluid experiences low pressure and becomes turbulent, causing the gas to break out from its solution form. This free gas travels upward through the tubing/casing annulus, and is thereby mostly diverted away from entering the pump intake. Problems such as gas interference, gas lock and gas pound can be greatly reduced, improving the efficiency and life of the pump.

The patented-design separator is assembled entirely of machined components, eliminating breakage commonly associated with welded connections.

Sand control tool upgrade. Kajon Oil Tools' Sandbuster sand control tool has recently been upgraded to make it more durable and efficient for longer periods of use. Kajon has developed a new

Fig. 3. Harbison-Fischer adjustable threaded polished rod.



fluoropolymer wiper capable of operating at temperatures up to 475°F while remaining extremely resistant to abrasion and oilfield chemicals. The wipers are custom molded from 100% thermoplastic resins with no recycled materials or fillers.

The new slick plastic wipers, with a Shore D hardness of 67, will not allow wellbore abrasives to become embedded in the tool or between the plunger and the working barrel.

The improved sand control tool, like the original Sandbuster (first discussed in this series in *World Oil*, March 1998, pages 64–65), is installed at the top of the plunger below the plunger cage, Fig. 2. On the downstroke, production fluid passes through the tool, where flow is slightly restricted by the cone-shaped interior, forcing fluid through radial holes on top of the wiper. The flushing action causes any accumulated sand to be carried upstream with the fluid. Radial holes equalize pressure on both sides of the wiper.

The bottom tool assembly replaces the seat plug. Its venturi shape causes trapped sand or solids to be pulled into the main stream of produced fluid on the downstroke and flushed from the plunger barrel contact area.

Adjustable threaded polished rod.

Crowley, Texas-based Harbison-Fischer, which was purchased earlier this year by global manufacturer Dover Corp., has recently introduced an adjustable threaded polished rod to allow simpler and safer spacing of the downhole sucker rod pump.

The patent-pending polished rod, which is Acme threaded and manufactured of fatigue-resistant steel, allows the sucker rod string to be raised or lowered along the threads, Fig. 3. This eliminates the need for a polished rod clamp used in conventional spacing procedures and minimizes associated work hazards.

The threaded polished rod installs above the polished rod and is attached to it by a coupling. A large, tapered bearing supports the pumping load and sits on a thrust plate on top of the carrier bar. Adjustment is accomplished by loosening a locknut and turning the adjusting nut with an adjusting tool until the desired spacing is acquired.

This assembly is available with 3/4-in. or 7/8-in. polished rod pins and is rated at 15,000 lb of maximum load. The 3/4-in. version has a 24-in. adjustment range, while the 7/8-in. version has a 36-in. adjustment range. Other sizes and load ranges are available on request.

Sand flush pump. Another new Harbison-Fischer tool for rod pumping applications is a patent-pending sand flush pump that gives the operator a method to extend pump run times when dealing with entrained sand or other particulates.

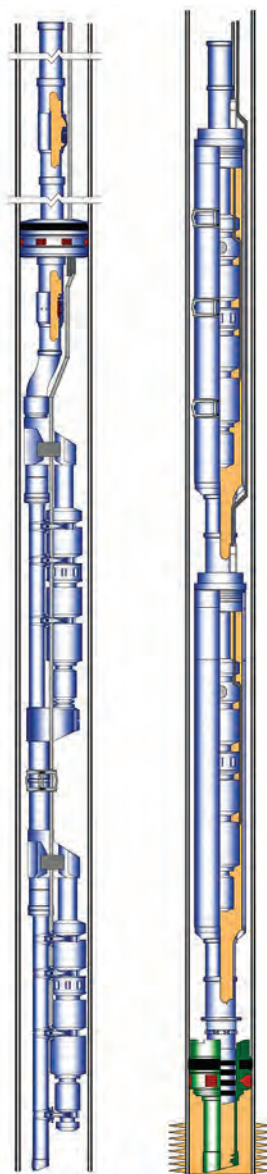
The leading edge of the top end of the pump's plunger is relatively sharp and tapered toward the inside of the plunger. On the pump's downstroke, angled holes direct fluid at this leading edge, effectively flushing sand away from the top of the plunger and keeping it suspended in the fluid. On the upstroke, sand and other particulates are directed to the inside of the plunger rather than between the barrel and plunger.

The new pump has been tested extensively in sandy wells in several production areas, and is available in all standard plunger sizes.

ELECTRICAL SUBMERSIBLE PUMPING

The push by E&P companies into increasingly challenging production environments worldwide has created an expanding market for electrical submers-

Fig. 4. Schlumberger dual ESP system in backup (left) and multizone configurations.



ible pumps that provide additional functionality, as well as tools to increase the functionality of existing ESPs.

Dual ESP system. Schlumberger's dual ESP system features a variable configuration that provides additional functionality, specifically for ESP backup and multizone production requirements. The company has installed more than 100 dual ESP systems in a wide variety of applications, including on- and offshore, for both backup and multizone ESP applications, Fig. 4.

The backup functionality allows operators to minimize time-consuming and costly workovers in the event of a primary ESP failure, while also extending the ESP

system run life. Additionally, having the backup option helps to minimize deferred production and also allows for improved workover scheduling.

Many countries impose regulations requiring independent production of fluids from different producing zones. The dual ESP system provides a means to comply with such regulations by producing multiple zones either independently or simultaneously. This is achieved by running either one or both of the ESPs in the dual ESP system. For multizone production applications, the system uses two ESPs, one of which is housed in a pod that includes a tailpipe string and seal assembly and is located in a seal bore packer situated between perforated zones. The pod-and-packer configuration isolates the producing zones. An upper ESP, which is installed above the pod, includes a bypass and produces the upper zone. Fluids from each zone are produced independently to the surface through the use of two tubing strings installed concentrically.

Both pumps are fully instrumented, and they also measure operational and production parameters for each pump and zone. The arrangement allows each ESP to be sized and operated optimally for its zone. A dual concentric tree prevents the commingling of production at surface. Additionally, it is possible to shut down one zone without affecting production from another.

Modeling software update. In 2010, Schlumberger updated its Avocet Well and Surface Modeler software with the release of its WSM 2010.1 software package, which provides a comprehensive design solution for ESP and gas lift systems. The 2010 release includes an intuitive workflow that allows users to navigate through the application design in a logical and concise manner.

Enhanced reporting features allow for the reformatting and improvement of all reports, as well as improved report loading times and customization options for content and plots. The application database has also been changed, providing trouble-free installation and smooth operation with Windows Vista and Windows 7 32-bit and 64-bit operating systems. Other changes include improved viewing in Vista and Windows 7 operating systems with updated color schemes and fonts, and a revamped help system and tutorials.

For ESPs, the software has been greatly enhanced, with an updated equipment database including new pumps and variable speed drives (VSDs). Users will experience an easier definition and better modeling of pressure loss and heat transfer for shrouds and pods. The 2010 release also includes additions for surface power source calculations and added support for user-specified inflow performance relationship curves.

The ESP design module provides a comprehensive well performance analysis solution for a complete ESP system design. The software uses fluids, well and reservoir data to predict the inflow and outflow performance of an ESP design. It sizes and analyzes an entire ESP system, with the goal to optimize pump design and greatly increase run life for increased production. The software package also provides a comprehensive selection of fluid models and correlations to match measured well data. An extended set of empirical and mechanistic flow correlations is also available, allowing users to match field performance.

Installation and reliability improvements. Recently, Schlumberger revamped its ESP volume stage portfolio and released a number of new stages that increase hydraulic efficiency and lift capability in its REDA line of ESPs. The company's new stage development process uses computational fluid dynamics modeling and prototype performance verification to optimize internal stage geometry and flow profiles in order to produce maximum possible efficiency and lift.

Higher hydraulic efficiency directly results in reduced motor horsepower requirements and total power consumption for an application, allowing for significant savings to the total cost of ownership of an ESP system.

Among the latest ESP stage developments is the D1050N stage, which is now the smallest and most efficient mixed-flow geometry stage in the REDA line for wells with approximately 1,000-bpd production rates, Fig. 5. Wider vane openings and smoother flow patterns allow the mixed-flow geometry to provide improved hydraulic efficiency, as well as gas- and abrasives-handling capacities, unlike radial flow stages that are normally used for similar production rates.

All REDA pumps with new stages are assembled in compression factory-shimmed design. This feature ensures that

the pump shafts are precisely matched at the factory to enable the axial thrust transfer directly to the high-load protector bearing, eliminating time-consuming and error-prone field shimming procedures. Combined with Maximus motors and factory-shimmed Maximus protectors, factory shimming of pumps reduces ESP installation time requirements by at least 60%, while also protecting the quality and integrity of the system by eliminating human and weather-related factors.

Increased operating temperature.

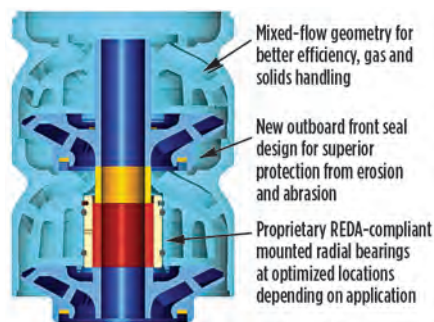
The Baker Hughes “ultratemperature” (UT) ESP system recently joined the company’s “extreme-temperature” (ET) and “high-temperature” (HT) systems within the Centrilift CENTigrade family of elevated-temperature ESP systems. The UT systems are rated up to 482°F fluid temperatures, the ET systems to 428°F and the HT systems to 320°F. The ET and UT systems are primarily applied in steam-enhanced recovery operations. The HT systems are applied in hot wells, wells with lower flow conditions, or wells likely to minimize pump production, such as those with gas-laden fluids, solids or scale.

As of February, 20 UT systems have been installed, accumulating more than 3,400 days of cumulative run life since the first installation on April 15, 2010. These milestones were accomplished with no failures attributed to the design or execution of the ESP system.

Steam-assisted gravity drainage (SAGD) applications present severe challenges to a standard ESP system. Extreme and cycling bottomhole temperatures, multiphase flow, abrasives and thick bitumen common to SAGD production can all be significant challenges for ESP systems. To improve the performance of SAGD operations and manage the risk of such capital-intensive projects, operators look for ways to reduce the steam-to-oil ratio and minimize the subcool and downhole pressure without jeopardizing steam chamber integrity.

The ET system has demonstrated reliable operation in these conditions. The new, more robust UT system will extend run life in a traditional SAGD application with fluid temperatures below 428°F, and will extend the product line to SAGD projects where the operator seeks to increase bottomhole temperatures over 428°F, **Fig. 6**. Injecting steam at these higher temperatures increases the size of the steam chamber, which is likely to improve recov-

Fig. 5. Schlumberger D1050N mixed-flow geometry ESP stage.



ery. At higher temperatures, the bitumen also becomes more missive, increasing the productivity of the well pair. Projections indicate that up to 50% incremental production can be realized by increasing the fluid temperature from 428°F to 482°F.

Typically a SAGD well pair is steamed or soaked for six to 18 months with an initial production period involving gas lift production. The UT system permits steam to be injected through it, allowing the gas lift phase to be skipped. This also avoids a workover by going directly to the higher-rate production of an ESP. By designing the well pair pad for one form of artificial lift, the gas lift infrastructure is eliminated, saving up to \$10 million in capital expenses per pad.

Rigless deployment. Using ESPs becomes costly in environments where pulling costs are high, such as offshore and remote onshore locations, as well as environments where changing well conditions require frequent interventions. To reduce these costs, UK-based Artificial Lift Company (ALC) worked closely with ConocoPhillips for more than five years to develop its Rigless ESP system, culminating in the operator’s approval of the wireline-deployed pump for commer-

cialization in October 2009. ConocoPhillips initially invested in the technology to reduce the cost of replacing pumps in sanded-up wells in its remote assets on Alaska’s North Slope.

Unlike other wireline-deployed ESP options that still require a workover rig to deploy the tubing-conveyed motor, the ALC system is fully retrievable and deployable by slickline, **Fig. 7**. A compact permanent magnet motor is connected to the pump section, which a wireline unit can deploy or retrieve in 4½-in. tubing with a 3.833-in. drift ID. The motor can produce up to 400 hp of power using industry conventional drives.

The initial pump installation still requires a workover rig to deploy an electric surface-to-bottomhole cable conventionally on the tubing string. A wet connector in the tubing string BHA links the cable to the wet-connector system on the ESP. The ESP deployment itself, as well as all future pulls and replacements, requires only wireline. Because of the short motor length, the entire system can be retrieved and deployed on live wells using a lubricator. The design using the wet connector in the side-pocket mandrel allows for full-bore intervention once the ESP is pulled.

A 3.8-in. Rigless ESP system accumulated more than 450 days in a commercial ConocoPhillips well using an ALC downhole wet-connect design. The pump is scheduled to be deployed commercially by IOCs and NOCs in North America, the Middle East and Asia in 2011.

GAS LIFT

New components and modeling software continue to increase both the effectiveness of the gas lift method and its applicability to a widening variety of artificial lift applications.

Fig. 6. Baker Hughes CENTigrade elevated-temperature ESP system deployed in a SAGD application.

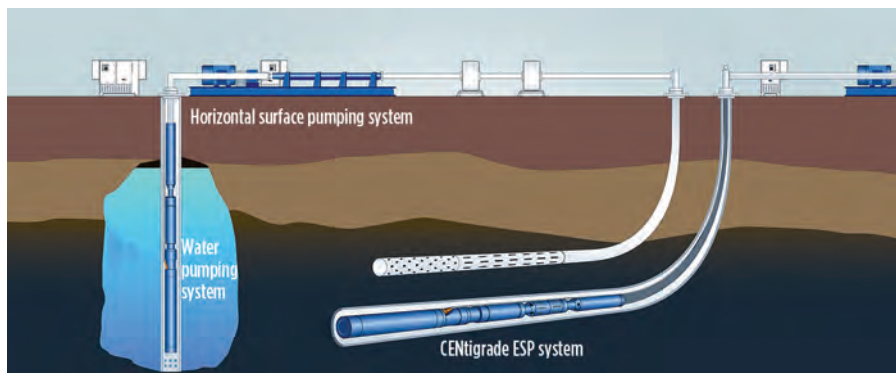


Fig. 7. ALC crane and lubricator during Rigless ESP installation.



Modeling software update. Already discussed in the context of its ESP design module, Schlumberger's updated Avocet Well and Surface Modeler software (WSM 2010.1) also has new features specifically for gas lift systems. These include improved calculations for test rack opening pressure, deepest injection point (DIP) and minimum valve spacing. The default design module has been changed from the injection-pressure-operated (IPO) surface close to the IPO minimum/maximum design. Additionally, the new software package includes improved DIP plot interactivity, with data modification and additional variables added for sensitivity analysis and case comparisons.

The gas lift design module is intended to help operators optimize gas injection depth, minimize downtime through continuous gas lift operation, and maximize production through best-suited gas lift equipment selection. The software defines the wellbore schematic and accurately sizes all downhole components. A comprehensive database of components includes the most recent gas lift equipment.

Disappearing valve plug. Baker Hughes has introduced a plug manufactured from an engineered material that dissolves when exposed to saltwater. The plug can be installed between the reverse flow check dart and lower flow ports of a wireline-retrievable gas lift valve or orifice valve to convert it to a temporary dummy valve. Installing the plug in the valves prior to installation in the side-pocket mandrels eliminates slickline intervention after the completion to remove the dummy valves and install live gas lift valves.

Dummy valves are often loaded in side-pocket mandrels when they are installed in completions to isolate the annulus from the tubing where pressuriza-

tion is required to test the tubing, test the annulus, set a hydraulic packer or activate an isolation device. If the well requires gas lift to unload the completion fluid or assist the well to flow, wireline intervention is typically required to remove the dummy valves and install the live gas lift string. The engineered material used to manufacture the plug installed in the live valve will not react with drilling mud, is slightly reactive with fresh water and will dissolve in 12–24 hours in saltwater, varying with temperature and other well conditions.

The plug is made of a nanostructured composite material recently developed by Baker Hughes material scientists and engineers. Proprietary nanoscale metallic and ceramic coatings in multilayer structures are applied to the matrix particulates to enhance the material strength, allowing its use for high-pressure-rated tools. At the same time, it can be designed to react and dissolve in typical wellbore fluids at a predictable and controlled rate for intended service conditions. The material can be designed to rapidly corrode in 5–15% hydrogen chloride. This interventionless valve technology is being investigated for deepwater high-pressure/high-temperature applications.

Gas lift check valves. Weatherford recently expanded its gas lift offerings with two new check systems for 1½-in.-OD gas lift valves and for use on its recently introduced DVX side-pocket gas lift mandrel. Both systems have been approved by Norwegian operator Statoil within the barrier qualification of its governing document WR0534 (version 2.02). Testing was conducted to 10,000 psi at 150°C (302°F), confirming the check systems' appropriateness for subsea and high-reliability gas lift operations.

One design incorporates a metal-to-metal seal with a unique flowpath that diverts flow away from the sealing surfaces, inhibiting flow cutting while injecting. The other design has a combination elastomer and metal-to-metal seal with more traditional flow-through geometry. The spring material for both designs is designed to withstand fatigue through extreme cycle rates. The system can be incorporated in many of the company's 1½-in. gas lift valve models, including the new DVX side-pocket mandrel.

GAS WELL DEWATERING

For many operators, plunger lift is the method of choice for dewatering natural

gas wells to allow production. Thus, new offerings to improve plunger lift represent an important category of artificial lift advances.

Trackable plunger. Well diagnostics for plunger lift systems have been improving over the last decade as the ability to insert pressure and temperature sensors into plungers has progressed. Making use of this improved technology, Denver-based Gas and Oil Technologies and Services (GOTEK) and Well Master Corporation developed the iViper Intelligent Plunger. The design adapts casing collar location technology to provide a reliable means of determining the location of the tool as it travels through the tubing string.

The plunger senses and records the number of tubing collars encountered as it travels down and back up the well. Upon withdrawal from the well and subsequent downloading, the pressure and temperature data is aligned with the collar count data. Adding in the time scale provides gradient information as well as plunger velocity.

One quick and easy application of the trackable plunger is to determine liquid levels in the tubing, **Fig. 8**. The change in pressure gradient on contact with the liquid can be easily seen using the included plotting software. The corresponding collar count is quickly established, and the depth at which liquid is encountered is automatically displayed.

Most operators to date have used the trackable plunger to evaluate plunger control settings and to aid in optimization. Knowing the liquid level, it is easy to determine the volume and to apply this in other calculations such as the Foss/Gaul model. Plunger off-time can be evaluated to establish optimum settings. Problems such as tight spots, interference from adjacent wells, compressor-related problems and holes in tubing can quickly be determined. Bottomhole pressure build rate can be measured and compared with casing pressure build rates. Longer-term bottomhole pressure buildups can be obtained in order to assist with reservoir calculations.

More than 20 of the trackable plungers have been put into operation at various operating locations around North America since their introduction in mid-2010.

Three-in-one plunger. Sapulpa, Oklahoma-based Hasco Manufacturing Company has developed a single plunger

Fig. 8. Data from the iViper trackable plunger for liquid level determination.

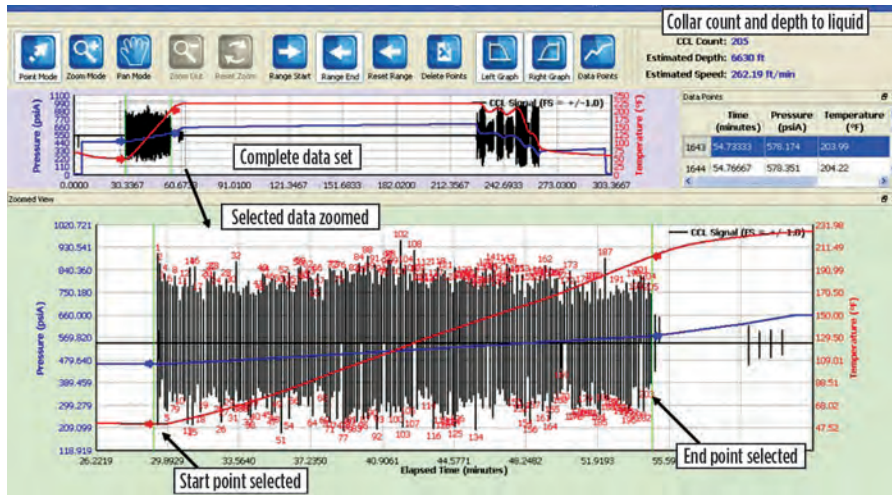
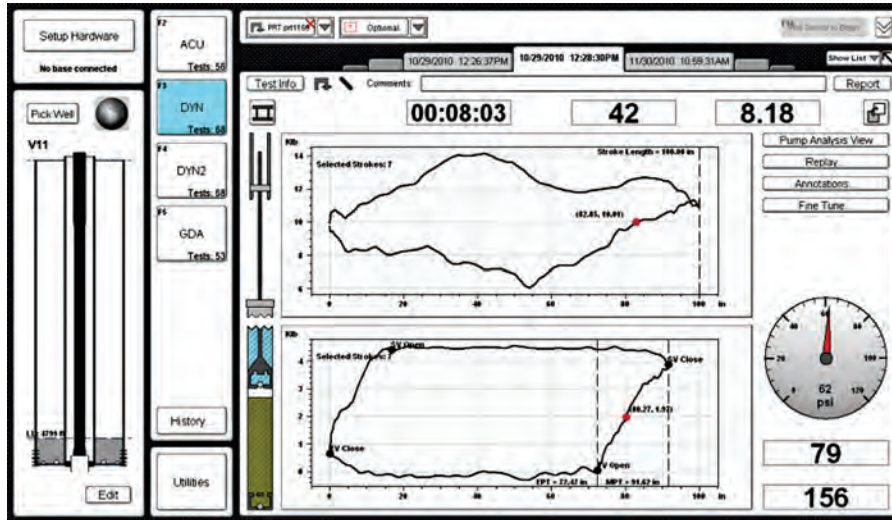


Fig. 9. Echometer’s real-time acquisition screen displays surface and pump dynamometer data, tubing head pressure and fluid level, obtained from wireless sensors, and a computed animation of plunger motion and pump fillage.



that combines three different plunger designs for complex dewatering applications. The company’s 3D Plunger design incorporates a pressure-actuated plunger with rings for sandy, gritty conditions; a precision metal-to-metal plunger for maximum efficiency; and an optional metal plunger with lubricating grooves.

The ring plunger portion clears abrasive material, helping to prevent excess wear and corrosion on the metal-to-metal portion of the plunger. Adding the optional lubricating grooves on the metal plunger surface allows more oil to work within the body of the plunger. The overall effect is to prolong the life and improve the efficiency of the plunger.

The three-in-one plunger is available in a variety of sizes and configurations. Custom ring configurations and lengths

are also available.

Plunger lift lubricator. As a result of few or no regulatory requirements, there is a wide variety of quality in the plunger lift lubricator market today. This has resulted in the compromise of wellhead/tree equipment, which is demonstrated by many documented failures. In an effort to minimize risks associated with these failures, Weatherford International has developed a high-pressure, cold-weather lubricator that is designed to the same standards and requirements as other wellhead components. The intent is to ensure that wellhead and tree mechanical integrity and operational safety are not compromised when transitioning to plunger lift operations.

The flanged lubricator is built to NACE MR0175/ISO 15156 standards of

API Class DD-NL material, and has material specifications and cold-weather certification to API Class L-U. It also meets the pressure vessel requirements of the ASME’s Boiler and Pressure Vessel Code.

The lubricator comes with either a standard external upset end (EUE) top connection or a Bowen union. It is manufactured in 2³/₈-in. R24, 2⁷/₈-in. R27 and 3¹/₂-in. R35 flange configurations with associated API 6A spacing requirements, which allows easy bolt-up to any flowline and eliminates the need for flow-tee bodies.

MONITORING PERFORMANCE

Operators are increasingly demanding real-time data and analysis to help them optimize their use of pumping systems, driving suppliers to offer more advanced diagnostic tools for artificial lift.

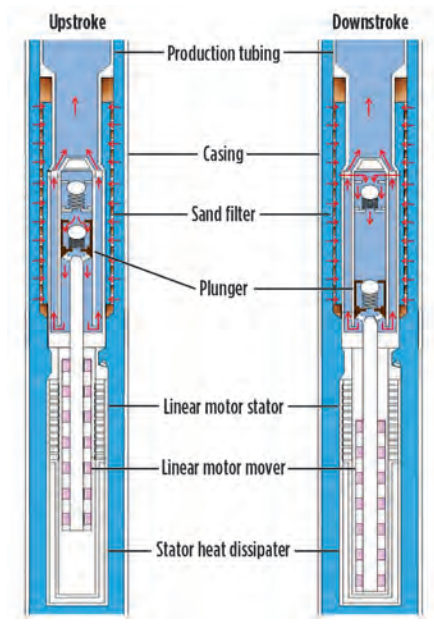
Real-time flowrates. In 2010, Schlumberger introduced a proprietary interpretation technique to provide real-time flowrate data without the need to retrofit additional hardware in the field, with the exception of downhole ESP gauges and a SCADA system, which in many cases is already available. Through the use of this real-time flowrate data, back allocation can be improved.

Real-time flowrate data represents a step-change in measurement over the once-a-month testing with manual data entry that is typical in wells that are not equipped with dedicated multiphase meters. The granularity provided is particularly important in wells where production fluctuates rapidly. Furthermore, many reservoirs produce at flowrates below the threshold required to achieve reasonable accuracy with test separators, making another means of flowrate determination necessary.

When downhole measurements are used, it is possible to plot flowrate, flow pressures and reservoir pressure accurately, which allows engineers to see production changes as small as about 10 bpd. Enhanced superposition analysis can be used to monitor real-time reservoir pressure based on flowing pressure, reducing the need for frequent buildups.

To accommodate the advances provided by this new real-time flowrate technique, the company’s LiftWatcher real-time surveillance service now hosts data from rod pumps, progressive cavity pumps and vortex flowmeters, as well as the previously supported ESPs and hydraulic production systems. This over-

Fig. 10. CSTek linear DC ESP schematic.



haul allows operators to have a better insight into the entire infrastructure rather than just portions of it.

ESP surveillance. Baker Hughes offers the Vision flexible ESP monitoring, surveillance and production optimization tool. By using a model-based system with expert system diagnostics, this approach to online monitoring, first introduced in 2009, allows users not only to see the most current information from their well, but also to track key performance indicators, trends, run life and predictive diagnostics. The system, scalable from one well to thousands, is available for an exhaustive variety of ESP systems, including both subsurface equipment and surface controls.

Data gathering is flexible: If the user already has a data collection system in place (such as a SCADA), the Vision system securely interfaces with the historian or database. If there is not a system in place, the surveillance system has data collection and control capabilities built in, and field technicians will install the necessary hardware and communications to enable it. The surveillance system can operate as a standalone system or tightly integrated into the company's Digital Oil Field infrastructure.

By accurately modeling the pumping system, the surveillance system and its algorithms establish a tight operating envelope. Baker Hughes AutographPC software generates specific operating curves, allowing up-thrust and down-thrust con-

ditions to be determined accurately and monitored, resulting in longer run life.

The system includes collaboration spaces for consultation both with other users and with company experts.

Workflows are a key component of the system: Daily workflows use exception-based reporting and morning reports; weekly and monthly workflows are also provided, with yearly views based on that data. Optional modules are available, such as NeuraFlow, a flow calculation system that provides accurate multiphase flow allocated to the individual ESP well.

Real-time dynamometer data. Within its Well Analyzer data acquisition and diagnostic system, Wichita Falls, Texas-based Ecometer has combined computerized analysis of dynamometer records with powerful portable computers, advanced modeling software, graphical user interface and wireless data acquisition.

The integrated system provides visualization of rod pump operation in real time. The operator directly observes and determines how the pump is filling with fluid, the relative amount of gas and liquid, the pressure variation during the plunger stroke, and the motion of the plunger and valves. This real-time information allows the operator to determine how efficiently the pumping system is operating and whether it requires modification or remedial intervention. The majority of the analysis is performed automatically and does not involve evaluation of numerical results by the user. When unusual conditions are observed, the user has access to advanced tools that facilitate detailed diagnostic analysis.

Real-time analysis and visualization of well performance are achieved using multiple wireless sensors that simultaneously transmit acquired data to a digital laptop manager. The laptop manager integrates the measurements, displays performance graphs and provides advanced tools for pump system analysis and troubleshooting. The battery-powered wireless sensors for fluid level, pressure and dynamometer data acquisition are easily deployed and quickly installed on the well.

All data is displayed during acquisition, Fig. 9. The user can select a detailed view of the action of the pump that includes a graph of plunger position, the corresponding pull rod load, and pressure inside the pump barrel.

DC LINEAR ESP

To round out this year's overview of new artificial lift technologies, a novel new pumping system from Taiwanese manufacturer CSTek combines aspects of beam pumping and ESP systems to avoid the pitfalls of each.

Beam pumping is well-understood and is the most popular method of artificial lift, but encounters many problems associated with its use of the sucker rod. The ESP has been an effective alternative allowing operators to do away with the rod, but its use of AC current as well as a rotary motor creates its own set of limitations. CSTek's solution seeks to make use of the reliable reciprocating pump without the requirement of the sucker rod, by employing a linear submersible motor driving the plunger of the reciprocating pump.

Problems encountered in the process of implementing this concept included generating sufficient thrust in the limited downhole space, reducing the amount of thrust required, and dissipating the heat generated by the linear motor. Using a rare-earth permanent magnet, the manufacturer designed a linear DC motor capable of generating 2.5 tons of thrust—sufficient for most wells that currently use sucker rod pumping. The motor moves the plunger of a specially designed two-way reciprocating pump. This two-way pump solves the problem of reducing thrust requirements by replacing the one-way pump used in sucker rod systems, so fluid can be lifted in both the upstroke and the downstroke, Fig. 10. Finally, in conjunction with a heat dissipater, a control system with an insulated gate bipolar transistor (IGBT) causes the motor to stop running at the top of the upstroke and the bottom of the downstroke to help dissipate heat.

Designed to replace most sucker rod pumps, the DC linear ESP (LESP) system is being marketed worldwide, with more than 100 units installed to date. Most installations are in China, while some are in California's Kern Valley oil fields. In field applications, LESP function and efficiency have been observed to be hampered by wax, sand and sticky oil, requiring flushing in wells exhibiting these conditions. However, the LESP has been observed to reduce complexity, reduce investment and maintenance cost, and reduce energy consumption by more than 50% compared with sucker rod pumps. **WO**



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He worked for Sun Oil as a research engineer from 1970 to 1975, taught at the University of Arkansas from 1975 to 1978, was team leader of production optimization and artificial lift at Amoco EPTG from 1979 to 1999 and was chairman of Texas Tech University's petroleum engineering department from 1999 to 2006.



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also works as a consultant to the oil and gas industry in artificial lift, specializing in gas lift.