Evolving Technologies: Electrical Submersible Pumps

Innovations in electrical submersible pump technology are paying off for oil companies, providing greater reliability, performance and endurance in harsh environments. From manufacturing to monitoring, advanced pump systems are helping oil companies optimize production while protecting their investments in downhole lifting technology.

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1. For more on artificial lift: Fleshman R, Harryson and Lekic O: "Artificial Lift for High-Volume Production," *Oilfield Review* 11, no. 1 (Spring 1999): 48–63.

The history of artificial lift is marked by innovation—often the result of gradual evolution in a product line, but sometimes the result of drastic redesign efforts. These changes have led to improvements in artificial lift, particularly with respect to electrical submersible pumps (ESPs).[1] New records of performance and endurance are opening up the range of ESP applications. Advances in design and manufacturing are making ESPs more resilient in hostile downhole environments, qualifying them for service at greater depth, increasing their gas-handling capability and making them more resistant to solids and abrasives.

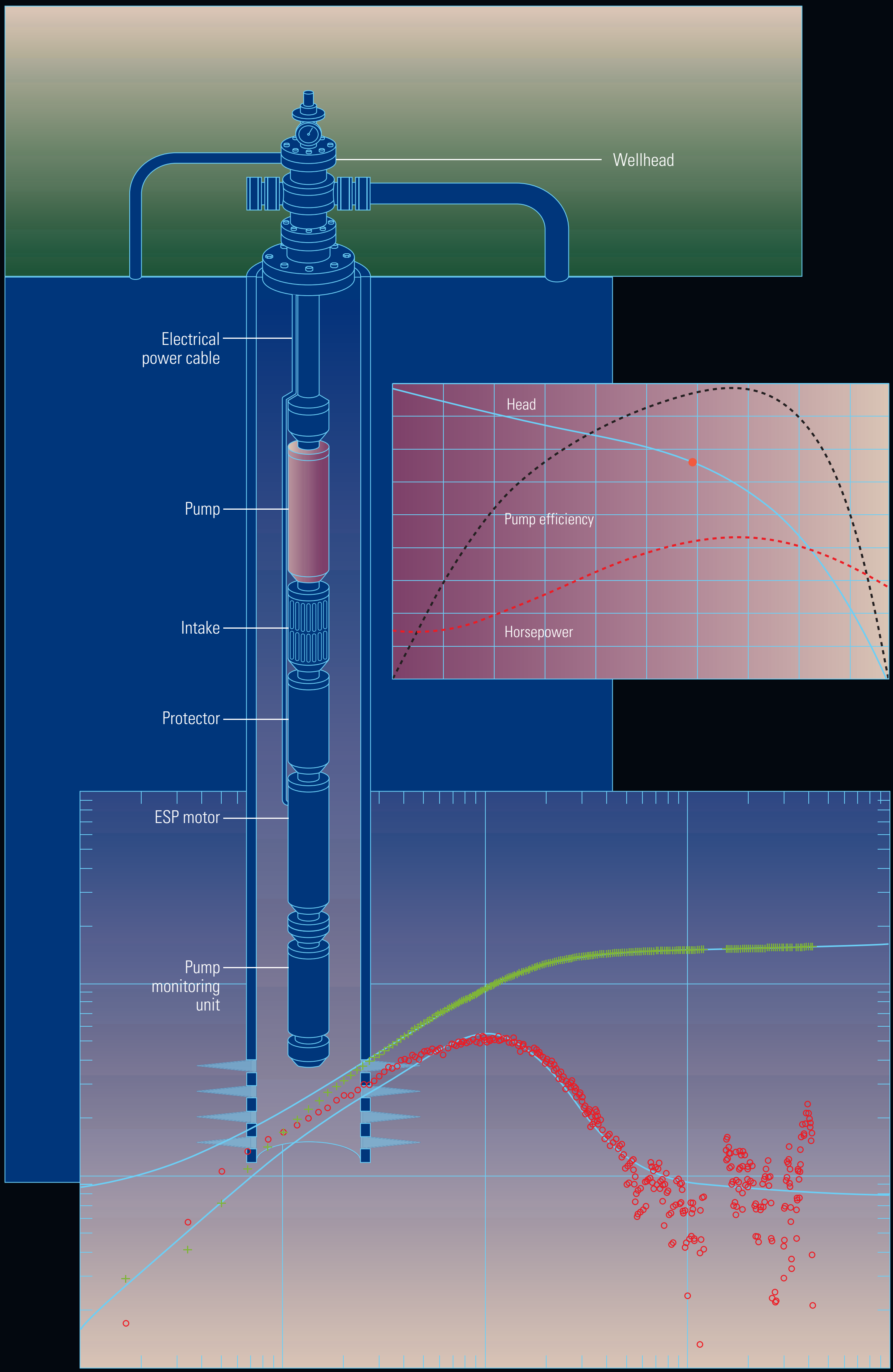
ESPs depend on movement of produced fluids to carry heat away from the motor. This requirement once limited ESPs to internal operating temperatures around 400°F [204°C]; certain pump models are now capable of operating at up to 550°F [288°C]. The use of produced fluids to cool ESP motors has also impacted the amount of gas that ESPs could pump before overheating. With advances in gas-handling components, ESPs with axial pumps can now handle free-gas fractions up to 75%. Other improvements in ceramics, metallurgy and elastomers are making ESP systems more resistant to abrasion caused by sand production. By extending the range of operating temperatures, gas handling and abrasive resistance of modern ESP systems, these advanced pumps can now be installed in wells that were once considered beyond the realm of ESP applications.

To get the most out of their pumps while protecting their investment in artificial lift, oil companies monitor ESP performance. With advances in sensor technology, operators are able to fine-tune the performance of the pump, the well and the reservoir. In Oklahoma City, downhole sensor readings are monitored and analyzed around the clock by a multidisciplinary team of specialists working at the Schlumberger Production Center of Excellence. At this facility, pump surveillance and reservoir-production engineers work in concert with operators to evaluate trends in pump and field performance. These trends alert ESP experts to downhole or surface problems early on, usually in time to take corrective measures. Even more, by monitoring downhole data during pump shutdowns or startups, reservoir-production engineers can provide pressure-transient analysis, to assist operators in evaluating reservoir performance.

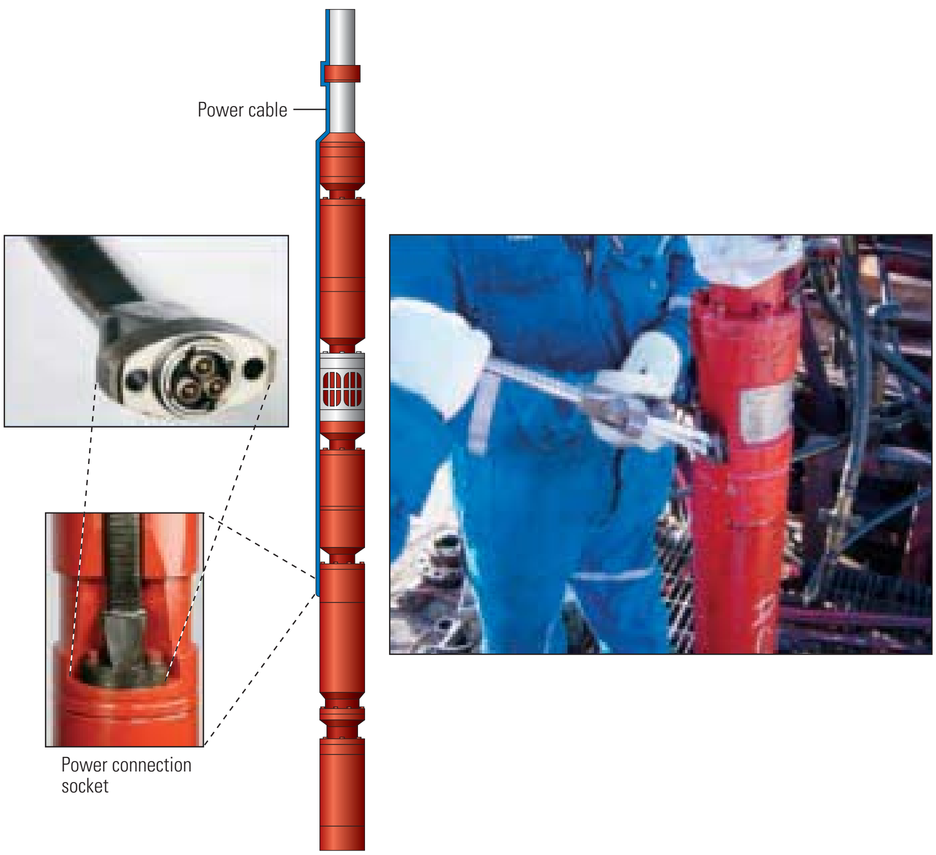
This article describes advances in ESP design, surface and downhole instrumentation, and centralized monitoring that are helping operators optimize pump and field performance. Examples from Canada and the North Sea highlight the growing range of successful applications for which electrical submersible pumps are being installed.

Improving Pump Design

One of the oldest axioms in the oil field is that critical operations invariably take place on weekends or holidays, in the middle of the night and during bad weather. While it is hard on personnel to install pumps in a driving rainstorm, blowing sand, or the wind, cold and snow of a blizzard, these surface conditions can also be tough on the pumps themselves. However, a new line of pumps was developed to meet these


Wellhead
Electrical power cable
Pump
Intake
Protector
ESP motor
Pump monitoring unit
Head
Pump efficiency
Horsepower

^ Siberian winter in a Russian oil field. To survive such conditions, pump components must be designed to withstand drastic changes in temperature. After the pump is made up, it is lowered into the depths of the wellbore, taking it from subfreezing surface temperatures to the extreme heat imposed by the geothermal gradient.



^ New electrical power connection. A redesigned connector (*left*) eliminates the practice of taping electrical connections at the wellsite (*right*), thus reducing the chance for tool contamination or human error.

conditions. Originally designed for installation in hostile environments exemplified by harsh Russian winter conditions, the REDA Maximus electrical submersible pump can handle extremes in surface and downhole temperatures that used to wreak havoc on pump installation and even cause early pump mortality (left).

Rather than evolving through a series of small design improvements, the REDA Maximus ESP was developed as a modular system engineered to enhance reliability and increase service efficiency and performance of downhole ESP systems. The Maximus system consists of integrated components using fewer and simpler mechanical connections than previous models. This system offers a range of configuration options. Operators who want a standard system in each well can install the ProMotor integral motor, protector and sensor unit. For installations that require more flexibility and custom application design, the Maximus motor and Maximus protector permit the operator to select application-specific protector types that will best function in combination with the motor horsepower and voltage required for a particular well.

Electrical power connections, as well as the connections between oil-filled components, have been engineered for greater integrity. Maximus motors use a new ESP motor connector-plug design that eliminates taping of electrical connections normally performed at the wellsite (below left). Oil-filled components that are connected at the wellsite, such as the motor and protector, use special ESP flange connections to prevent these components from trapping air bubbles while making up connections in the field.

The Maximus design also removes certain critical installation operations from the wellsite. Before delivery to the field, Maximus motors, protectors or integrated ProMotor units are filled with oil, and the protectors are shimmed to ensure proper shaft spacing. Formerly carried out at the wellsite, these procedures are now performed indoors, in the controlled environment of a REDA service facility, eliminating the risk of improper filling or shimming under difficult field conditions (next page). This process reduces exposure of the dielectric oil to wellsite contamination by precipitation, sand or dust.[2] These improvements in service quality also helped to simplify the installation process of the Maximus unit, resulting in a significant reduction in rig time compared to previous ESP technologies.

By eliminating sensitive and critical assembly operations required during conventional ESP installations, Maximus technology reduces exposure to potential environmental problems and human errors. In applications where early, short-run pump failures are often attributed to installation problems or human error, Maximus ESP systems have demonstrated a significant reduction in operational and equipment problems, especially short-run failures.[3]

Another problem that shortens the life of ESP motors and protectors is caused by wear on the radial bearings. These bearings become worn as the ESP motor oil degrades over time. To extend the life of Maximus ESPs, all radial bearings have hardened shaft sleeves that run in self-lubricating bushings.

Vibration also plays a significant role in reducing pump life. When the motor shaft vibrates, it increases wear on the seals around the shaft, eventually permitting fluids produced from the well to leak into the protector. From the protector, wellbore fluids can seep past the shaft seals and into the motor itself, where they contaminate the motor oil and change its dielectric, hydraulic and lubricating properties, ultimately causing failure of the pump motor. The protector-head bearing, which is affected by vibration from the pump intake and abrasives in the produced fluid, uses an abrasion-resistant zirconia bearing.

^ Assembly in a controlled environment. Modular bolt-on components allow critical assembly procedures to be carried out at the shop, rather than the wellsite. Personal protective equipment shown is according to local risk-based plan and Schlumberger standard; gloves are not used in this process to avoid contamination by cotton fibers.

Oil companies can guard against pump vibration damage by monitoring ESP performance indicators and changing ESP motor speed. Maximus motors offer a gauge-ready base that allows direct connection of the Phoenix artificial lift downhole-monitoring system so that operators can track ESP and reservoir performance.

Downhole Monitoring

By monitoring ESP performance, operators can recognize problems as they develop. In many cases, pump performance declines gradually, leaving operators with time to proactively intervene if they are aware of the problem. Phoenix sensors provide a steady stream of real-time pump measurements. By tracking downhole pump characteristics, operators can recognize deviations from established trends and then take action to extend pump life and improve production. These pump measurements are also important for evaluating reservoir behavior, providing valuable information used in pressure-transient analysis, inflow-performance monitoring and productivity trending.[4]

Phoenix sensors provide a variety of downhole measurements and response options. Sensors include the following:

- Current-leakage sensor: protects the electrical system from excessive pump heat, breakdown of electrical motor winding insulation and phase-to-ground insulation loss.
- Discharge-pressure sensor: protects the pump from high pressure caused by closed-valve shut-ins and heavy fluid slugs.
- Intake-pressure sensor: protects the pump from low pressure caused by low fluid level, pumpoff caused by blocked intakes, and gas locking.
- Intake-temperature sensor: protects the pump from overheating caused by high-temperature intake recirculation and elevated production-fluid temperature.
- Motor-oil or winding-temperature sensor: protects the motor from high temperature caused by low-flow conditions, high motor load and poor cooling due to scale buildup.
- Motor- and pump-vibration sensor: protects the pump from vibration and mechanical damage caused by extensive solids production and excessive mechanical wear.

Each of these measured parameters can be programmed to trip an electrical switch at a given threshold, immediately shutting down the motor to protect it from further damage. In many installations, the operator can remotely adjust pump parameters to correct a problem. Thus, if an alarm is tripped, the operator may be able to transmit adjustments to pump speed to reduce vibration, or increase pump speed to move more cooling fluid past the motor, or apply backpressure to move solids out of the system.

2. Dielectric oil is an insulating oil used in electrical equipment. A poor conductor of electricity while being an efficient supporter of electrostatic fields, dielectric oil resists breakdown under high voltages and is used in ESPs to protect electrical components from corrosive elements in the wellbore.

3. ESP short-runs are failures that occur within the first 90 days of operation.

4. For more on downhole monitoring technology: Al-Asimi M, Butler G, Brown G, Hartog A, Clancy T, Cosad C, Fitzgerald J, Ingham J, Navarro J, Gabb A, Kimminau S, Smith J and Stephenson K: "Advances in Well and Reservoir Surveillance," *Oilfield Review* 14, no. 4 (Winter 2002/2003): 14–35.

Surface Controls

ESPs are driven by induction three-phase electrical motors, powered by a surface electrical supply. This power supply can be regulated to fine-tune pump performance as reservoir conditions change. By matching pump performance to changing well conditions, operators can improve ESP system efficiency and run life.

The SpeedStar variable speed drive is a surface control unit that allows operators to remotely adjust the electrical power sent downhole (right). This variable-speed drive (VSD) is an electronic device that synthesizes a three-phase variable-voltage, variable-frequency power supply for induction motors. Its output filter produces a nearly sinusoidal output voltage and current that prevent pump vibration and increase motor efficiency. It is also equipped with a transient-voltage surge suppressor to protect against electrical utility-fed power surges or lightning strikes on the system.

The SpeedStar VSD lets the operator control ESP motor speed and performance by adjusting frequency, which thereby adjusts voltage, transmitted to the motor.[5] The VSD provides constant torque through the entire speed range, enabling the ESP to produce a wider range of fluid volumes than would be possible at a fixed motor speed. As well conditions change, the capability to make fine adjustments to motor speed and torque can forestall the need to resize the pump, reducing downtime and production costs.

In some wells, operators can change the motor operating frequency in one-hertz increments to reduce pump vibration. By varying pump speed in a new or reworked well, a VSD can help determine the optimal flow rate of the well to avoid pumpoff and cycling problems. To provide a soft start during critical startup operations, the VSD is used to reduce voltage to the motor and ease strain that would otherwise result from starting the motor under full load at full speed. These measures help to extend pump life, especially in wells that are prone to frequent shutdowns.[6]

^ Variable-speed drives (VSDs). These surface units regulate and condition electrical current for five wells in Canada. Using electricity generated by the local electric utility or from dedicated generating stations, the VSD transmits power downhole to the ESP. The VSD is key to remotely controlling pump performance.

Expanding the Realm of Applications

A prime example of an ESP application that pushes the boundaries of traditional installations is the REDA Hotline high-temperature electrical submersible pump system. This ESP system was designed for wells with high bottomhole temperatures (BHTs), or wells with high oil cut, low fluid velocity and emulsified or gaseous fluids. These conditions are hard on system components, which rely on produced fluids flowing past the ESP to carry off heat generated by the motor.

Insufficient cooling adversely affects the oil inside the motor and invariably leads to malfunctions and premature failures of the system. While temperature ratings of standard ESP strings have climbed from 250°F [121°C] to 400°F [204°C], key components of the original Hotline system, especially its motor, power cables, pump and oil-filled motor protector are rated to 475°F [246°C]. This system has demonstrated substantial increases of run life when compared with conventional ESPs in high-temperature applications.

The need for high-temperature ESP systems is growing as the oil industry matures (next page). With most of the world's oil resources concentrated in heavy and extra-heavy oil and bitumen, oil companies are searching for ways to profitably extract these viscous reserves.[7] Some are turning to steam-assisted gravity drainage (SAGD) wells. The SAGD approach utilizes a pair of horizontal wells drilled parallel to each other, and separated vertically by a distance of about 5 m [16 ft]. Steam injected through the uppermost well penetrates the surrounding formation, heating the heavy-oil sands and creating a high-temperature region above the injector known as a steam chamber. Heat transferred to the oil sand reduces its oil and bitumen viscosity.

5. In these ESP systems, frequency is directly proportional to speed. By changing frequency, the operator also changes pump speed.
6. Bates R, Cosad C, Fielder L, Kosmala A, Hudson S, Romero G and Shanmugam V: "Taking the Pulse of Producing Wells—ESP Surveillance," *Oilfield Review* 16, no. 2 (Summer 2004): 16–25.
7. For more on heavy-oil extraction: Alboudwarej H, Felix J, Taylor S, Badry R, Bremner C, Brough B, Skeates C, Baker A, Palmer D, Pattison K, Beshry M, Krawchuk P, Brown G, Calvo R, Cañas Triana JA, Hathcock R, Koerner K, Hughes T, Kundu D, López de Cárdenas J and West C: "Highlighting Heavy Oil," *Oilfield Review* 18, no. 2 (Summer 2006): 34–53.
8. The SOR is a measure of the volume of steam required to produce one unit volume of oil. In SAGD wells, typical SOR values range from 2 to 5. The lower the SOR, the more efficiently the steam is utilized. Efficiency impacts the economics of the project because of fuel costs required to generate the steam.
9. Solanki S, Karpuk B, Bowman R and Rowatt D: "Steam Assisted Gravity Drainage with Electric Submersible Pumping Systems," presented at the 2005 SPE Gulf Coast Section Electrical Submersible Pump Workshop, The Woodlands, Texas, April 27–29, 2005.
10. For more on developing remote fields: Amin A, Riding M, Shepler R, Smedstad E and Ratulowski J: "Subsea Development from Pore to Process," *Oilfield Review* 17, no. 1 (Spring 2005): 4–17.

Gravity forces the oil, bitumen and condensed steam downward, where these fluids, consisting of about 25% to 40% water, are produced into the lower well.

Initially, gas lift was used to pump the fluids to surface in these high-temperature wells (see "The Pressure's On: Innovations in Gas Lift," *page 44*). With advances in ESP technology, many operators are replacing their gas lift systems with ESPs. The shift toward ESPs prompted further modifications to the Hotline system. This led to development of the Hotline 550 ESP system, which was built to serve in high-temperature wells produced by steamflood. In light of the fact that ESPs were formerly constrained by operating temperature, their use in SAGD wells may be considered revolutionary.

The Hotline 550 design accounts for variable expansion and contraction rates of different materials used in the pump, and components are rated for internal operating temperatures of 550°F [288°C]. The operating temperature represents the internal temperature of the system components, which is generally higher than the temperature of the produced fluids, owing to heat generated through mechanical and electrical losses at the pump, motor, intake and protector. Like other ESP designs, heat in this pump is carried off by produced fluids.

The Hotline 550 pump motor is protected by a special metal bellows system and shaft-seal mechanism that create a barrier between hot well fluids and internal motor oil—features never used in previous ESPs. The metal bellows compensate for expansion of the oil inside the pump motor. Other ESP designs—which rely on elastomer bag- or labyrinth-type protectors—can leak, allowing produced wellbore fluids to seep into the motor and contaminate the oil contained inside (see "ESP Protectors," *next page*).

Other components, such as the power cable, bearings, shaft seals, winding insulation and motor oil, have been redesigned or constructed from special materials to withstand high temperatures and improve system reliability.

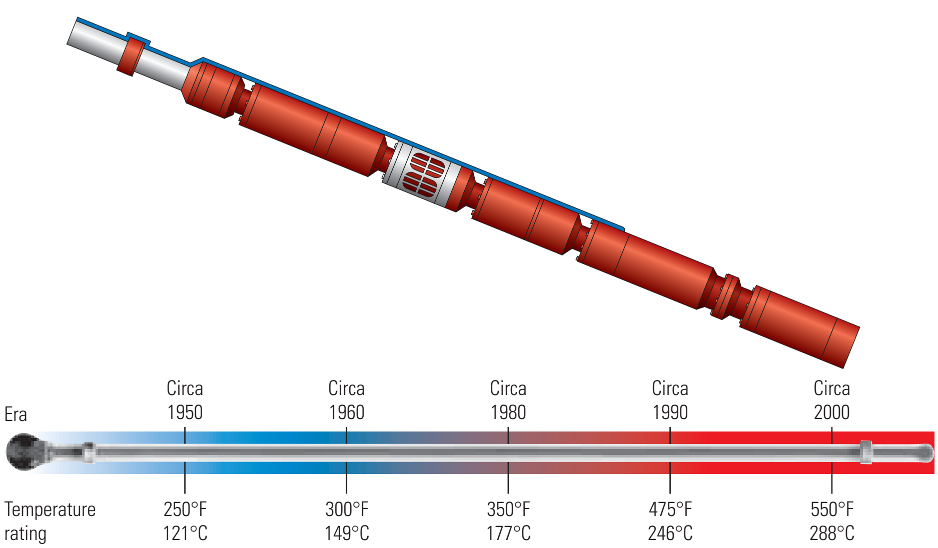
The Hotline system has been used extensively in Canada. In three fields in western Canada, EnCana Oil & Gas Partnership uses SAGD technology to recover 10.5° to 13°API bitumen and heavy oil. Wells in the Foster Creek, Christina Lake and Senlac fields produce from unconsolidated sands and have bottomhole pressures of 2 to 3 MPa [290 to 435 psi] and bottomhole producing temperatures of 180°C to 209°C [356°F to 408°F]. In 2002, EnCana began testing ESP systems as an alternative to gas lift methods.

In SAGD wells, economics are greatly impacted by the cost of steam generation and recovery. Steam accounts for 35% to 55% of the total extraction cost, which can reach several million dollars yearly for each well. These costs are proportional to the operating steam/oil ratio (SOR), so SAGD operators try to optimize reservoir pressure to achieve low SOR and high production rates.[8]

Lower SORs can be achieved by lowering the formation pressure in a reservoir. Low reservoir pressure enables the steam to carry higher latent heat into the formation where the heat can mobilize the oil. However, reducing reservoir pressure can also reduce the efficiency of gas lift to an extent that makes gas lift impractical. At lower pressures, pumps must be used to lift the fluids to surface.

EnCana successfully field-tested Hotline ESPs in two wells in Foster Creek field, achieving 645 days and 309 days of run life, respectively.[9] Temperatures of 209°C and numerous shutdowns demonstrated that Hotline systems could handle upsets and thermal cycling. Following these field tests, EnCana replaced gas lift systems with Hotline 550 ESPs in 11 wells in Foster Creek field, three wells at Senlac field and one at Christina Lake field. The company also chose Hotline ESPs for initial installation in five wells at Foster Creek field and three wells at Senlac field.

Following a reduction in reservoir pressure below levels required for gas lift, the operator's production data showed that SOR decreased by approximately 20%. This enabled EnCana to transfer steam to newer wells and improve overall production in their fields. Across Canada, Schlumberger has installed over 60 Hotline ESP systems in SAGD wells, and all are operating at BHTs in excess of 204°C [400°F]. The longest-running Hotline unit, installed in February 2004, is still running as of January 2007, in excess of 1,070 days; the longest-running Hotline 550 pump was installed in June 2004, and has continued to run more than 940 days.



^ ESP temperature-rating time line. New ESP applications are gradually pushing the temperature envelope. Temperature ratings have steadily climbed since the 1950s, with significant gains achieved since the early 1990s.

Subsea Applications

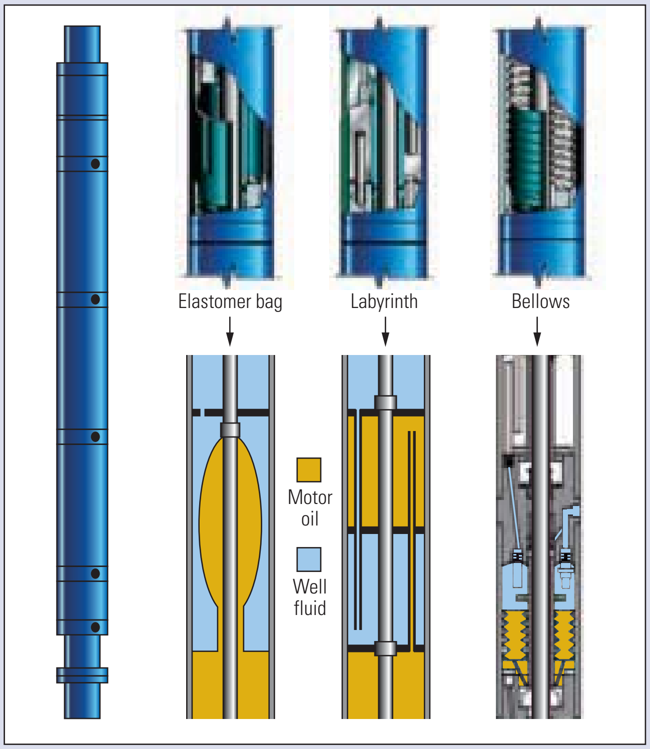
With improvements in reliability, ESPs are making significant contributions to production in offshore fields. Some of these offshore fields are incapable of supporting their own dedicated production infrastructure because of meager reserves or remote locations. To be developed, such reservoirs must be tied back to existing infrastructure.[10] ESPs are playing an important role in recovering these stranded reserves.

Following the 1973 discovery of Gannet field in the UK North Sea, several satellite reservoirs were tied to the Gannet facility by Shell Expro, UK, operator of this joint venture between Shell UK Ltd. and Esso Exploration & Production UK Ltd. The field lies 180 km [112 mi] east of Aberdeen, in 95 m [311 ft] of water. Subsea satellites produce the Gannet B, C, D, E, F and G reservoirs from turbidite sands of Tertiary age,

ESP Protectors

In an ESP string, the protector lies between the pump and motor. It has numerous functions:

- Carrying upthrust or downthrust developed by the pump: These forces are distributed over the large area of the protector thrust bearing. The bearings must therefore be rated higher than the maximum thrust that the pump will generate.
- Coupling torque developed by the motor to the pump: The protector shaft must be capable of delivering full torque without exceeding its yield strength, which could result in a broken shaft.
- Keeping well fluids out of the motor: The protector transfers pressure between the motor oil and the produced fluid in the annulus without allowing any mixture of the two fluids.
- Providing a reservoir of fluid to accommodate thermal expansion of motor oil: Pump installation subjects an ESP to increases in temperature between surface and setting depth. During operation, internal heating raises the temperature even further. The temperature increases cause the dielectric motor oil to expand. The protector accommodates this expansion, allowing the excess expanded volume of oil to move from the motor to the protector, displacing an equal amount of wellbore fluid from the protector and into the wellbore. When a motor shuts down, the motor oil contracts as the motor cools, and the protector provides a reservoir of clean motor oil to flow back into the motor while keeping the wellbore fluids separated. If the motor were to shut down without benefit of a protector, the motor oil would contract as the motor cools, creating a vacuum that would then be filled with wellbore fluids.

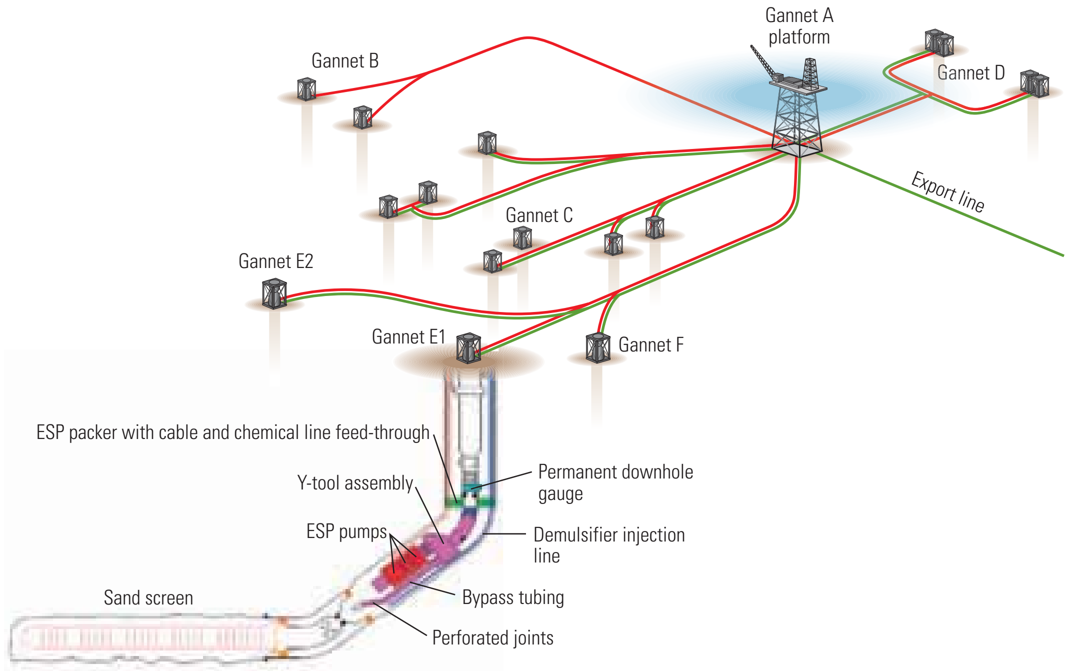


< Evolving protector design. ESP protectors are critical for preserving the integrity of the pump's electric motor. Positive-seal elastomer bags are used in many applications, but do not have sufficient tensile strength or temperature tolerance for SAGD wells. Labyrinth-style protectors use a tortuous path to limit wellbore fluid entry, but are not suited for horizontal installations typical of SAGD wells. The positive-pressure, metal bellows allows for pressure equalization and expansion of the dielectric oil in the motor.

Protectors generally fall into three categories: the labyrinth, the bag and the bellows designs (above right). The labyrinth design uses the difference in the specific gravity of the well fluid and the motor oil to keep them separate, even though they are in direct contact. For this design to work, the well fluid has to be heavier than the motor oil, and the unit must be installed vertically or nearly vertical in the well. In wells with high gas/oil ratios, the specific gravity of well fluid may be lower than that of the motor oil.

In deviated wells, the bag-type protector may be more suitable. This design uses a high-temperature, high-performance elastomer bag to separate the well fluids on the outside from the clean motor oil inside. The bag flexes to accommodate thermal volume changes in motor oil. However, it is rated to only 400°F, and as with all elastomer seals, the bag is susceptible to abrasives and can be breached if exposed downhole to chemically incompatible liquids or gases such as hydrogen sulfide [H_2S]. Exposure to elevated temperatures can also harden the bag and seals, causing a loss in elasticity that is eventually followed by failure.

The elastomer bag and labyrinth protectors usually perform adequately in the downhole conditions for which they are rated. The bellows-type protector is better suited for hostile downhole conditions, where protectors are subjected to high temperatures, abrasives, harsh well-treatment chemicals, carbon dioxide [CO_2] or H_2S. It is filled with an oil that retains viscosity at high temperatures and uses a metal bellows to accommodate thermal expansion and contraction of the oil. Using materials selected to minimize thermal stresses, it is rated up to 475°F internal oil temperature. The bellows are also rated for 30% H_2S concentration, depending on temperature.



^ Gannet field layout. Two wells from the subsea Gannet E field are produced by ESPs. Heavy oil produced from each well is commingled, and production from this field is tied back to the Gannet A platform. Power supplied through variable-speed drives on the Gannet A platform is transmitted via underwater electrical umbilicals to the subsea ESPs. (Adapted from Harris et al, reference 12.)

found at depths ranging from 1,768 m to 2,728 m [5,800 ft to 8,950 ft]. These satellites are tied back to the centrally located Gannet A production platform (above).

The Gannet E field uses ESPs to produce oil and gas to the Gannet A platform.[11] This field lies 14 km [8.7 mi] away from the Gannet A platform. Discovered in 1982, it was originally designated as the Guillemot C field, slated for development from the Guillemot complex. When the Guillemot A reservoir was later integrated into the development plan of a nearby field, Guillemot C and D reservoirs became stranded. In 1994, production from these fields was relegated to the Gannet platform and they were renamed Gannet E and F, respectively.

Gannet E field produces a thick, 20°API heavy crude with a reservoir viscosity of 17 cP [0.017 Pa.s] and a gas/oil ratio of 110 ft^3/bbl [19.8 m^3/m^3]. Initial reserves were estimated at 132 million barrels stock tank oil in place [20 million m^3], with a recovery factor of 43%. The field was developed in two phases. At peak production, the field produced at a rate of 14,000 bbl/d [2,225 m^3/d]. The transport and handling characteristics of this heavy and viscous crude, combined with low reservoir pressure, made artificial lift necessary for starting the well and producing its fluids back to the Gannet A platform.

ESPs were preferred over other methods of artificial lift because they could produce at higher volumes and handle fluids better than other systems. However, the operator was concerned that short run-life problems common to many ESPs would adversely affect project economics. Shell Expro wanted an ESP that could run two years before replacement. Testing was conducted to evaluate the subsea cable needed to conduct electrical power to the ESP, resulting in the development of a simulation tool to predict system stability over various lengths of cable (see "ESP Power Modeling for Improved Run Life," *next page*). The operator also wanted a pump capable of handling reservoir and fluid changes that could occur over the service life of the pump. After a fluid sample was obtained during Phase 1, with the drilling of a 2,800-ft [853-m] horizontal well, a production test was carried out and the pump design was finalized.

The first Gannet E well was completed with a prepacked screen and an ESP, becoming the first subsea development on the UK continental shelf of the North Sea to use ESP technology, and at the same time setting a record for the longest subsea tieback of an ESP.[12] The pump was suspended from a "Y" tool that would allow a wireline bypass for setting a plug below the pump in the event the pump needed to be removed. A Phoenix downhole gauge was used to monitor pump-inlet conditions. These conditions are monitored on the platform, and data are transmitted to Shell in Aberdeen and to Schlumberger in Inverurie, Scotland. This arrangement allows ESP specialists to monitor pump performance in real time, and to request changes in pump settings in response to changing conditions downhole.

First oil was produced from the Phase 1 well in January 1998. The ESP operated for 17 months before a workover was required due to problems between the tail pipe and polished bore receptacle. The flow rate was 19,000 bbl/d [3,019 m^3/d] with 900 hp required for the pump.

Experience gained from installation, operation and workover of the first well was incorporated into planning and execution of the next well, which was drilled and completed in

(continued on page 40)

11. MacFarlane JS: "Gannet E: The World's Longest Subsea ESP Tie-Back," paper SPE 38534, presented at the SPE Offshore Europe Conference, Aberdeen, September 9–12, 1997.

12. Harris G, Lowe P and Holweg P: "Technical Challenges and Solutions for Subsea ESPs in the North Sea: Two Wells Tied Back 15 km to the Shell Gannet Platform with Flow Commingled into a Single Flowline," paper presented at the SPE Gulf Coast Section's 19th Annual ESP Workshop, Houston, April 25–27, 2001.

ESP Power Modeling for Improved Run Life

In an effort to improve run life, Schlumberger ESP engineers have developed an electrical-simulation model to evaluate electrical failures under a variety of downhole conditions. The model was tested in a well by specialists from the Schlumberger Assembly, Repair and Test (ART) Center in Inverurie, Scotland, where almost 20 km [12 mi] of cable was connected between a surface variable-speed drive (VSD) and a downhole ESP motor.

This model showed that a common mode of failure among ESP motors is the electrical short, a condition often caused by breakdown of insulation around wiring used in electrical motor windings, cables and penetrators. Such insulation breakdown can occur through several different mechanisms:

- Contamination of the pump's insulating motor oil by fluids produced from the wellbore
- High motor temperature, a function of ambient temperature, motor load, fluid composition and fluid velocity past the motor
- Voltage stress caused by harmonics in the electrical power transmitted between the VSD and the ESP. Electricity flows in sinusoidal waves as it is transmitted along the length of electric cable. These waves can be reflected as they travel back and forth along the cable, moving from the VSD to the ESP and back again to the VSD. Like ocean waves, the sinusoidal electrical waves can build upon each other to create amplified waves that exceed the electrical rating of the downhole motor, cable or penetrator. Such amplified waves can easily peak in excess of three times the rated voltage output of the VSD. This amplified voltage can degrade insulation that covers the electrical wiring used in the ESP, eventually causing a short in the system.

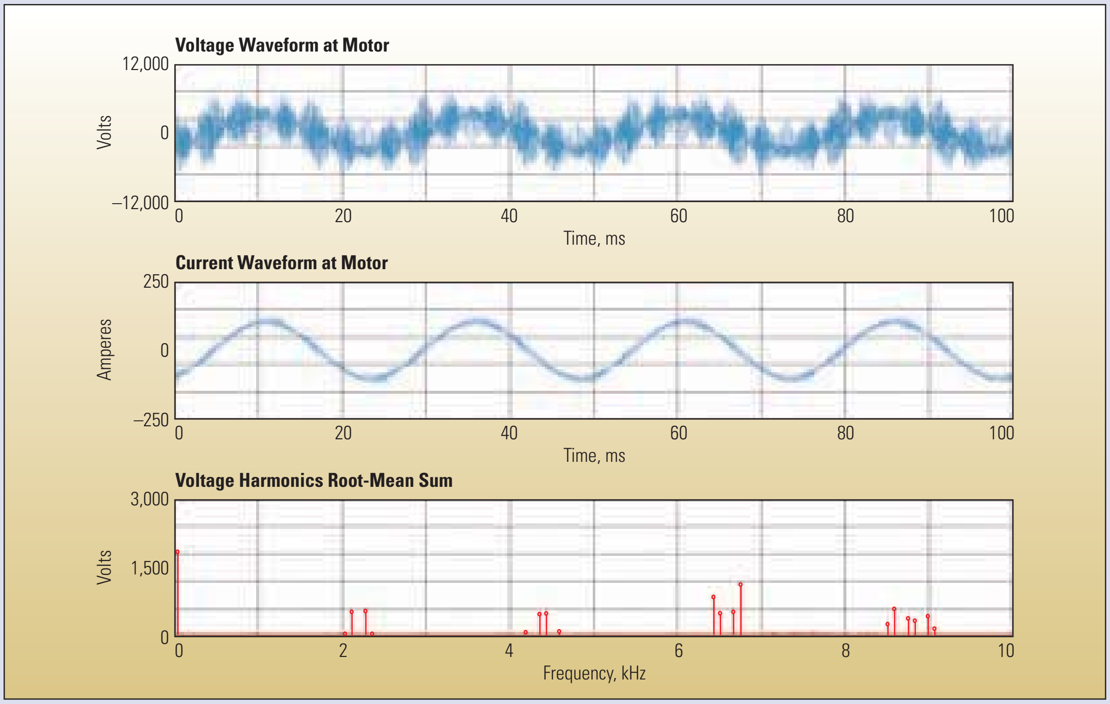
Contamination by produced fluids and high motor temperatures are problems that can be resolved by selecting the correct type of protector, or by changing the load on the line and the motor. However, the problem of harmonics requires a thorough understanding of the downhole system. Every VSD produces some degree of output harmonics, and the length of most ESP power cables exacerbates this problem. The magnitude of output harmonics depends on the entire electrical system: the ESP motor, the downhole cable and the wellhead penetrator; in subsea wells, the wet-mate connection, submarine cable and transformers are also involved. If one component in this system is changed, then the harmonics will change as well.

Based on testing of ESP system components, Schlumberger engineers in Inverurie developed a model to calculate performance of an ESP electrical circuit. Working closely with their colleagues in Inverurie, power-system engineers at the Schlumberger Edmonton Product Center (EPC) in Alberta, Canada, developed modeling software that can display overall harmonics for both current and voltage, creating a harmonics signature for the entire system (next page). The particular ESP application and operating conditions will affect the level of harmonics permissible for that specific system. Sensitivities to changing components can also be simulated in the model, with the model predicting consequences of corrective action, such as adding electrical filters, varying the carrier frequency of the VSD or changing the type of VSD used.

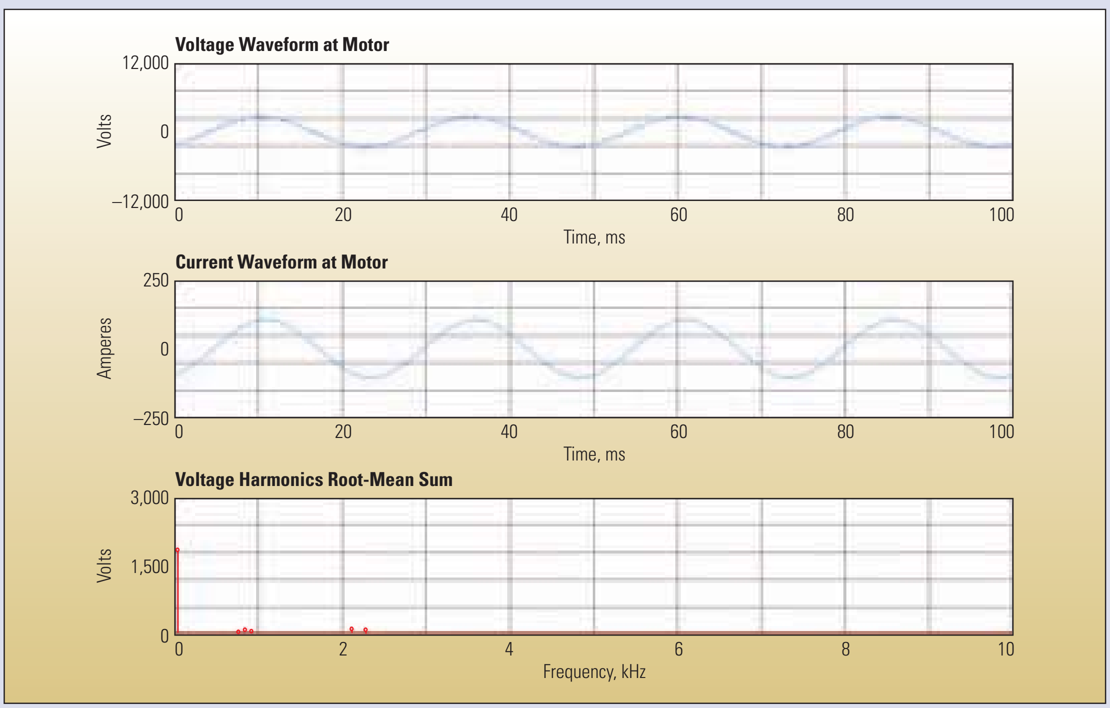
Another important reason for modeling the ESP electrical system is to determine the amount of power required to start the ESP motor, along with any limitations inherent in the system. ESP startup can be jeopardized by insufficient power to the motor. Because most wells require several thousand feet of power cable to transmit power from the surface VSD to the downhole ESP, they typically experience a large voltage drop across the length of cable. The effects of this voltage drop must therefore be factored into the design and operation of the ESP system.

Power-system engineers at the EPC have used the same modeling software to simulate ESP motor startups. This simulation package helps EPC engineers to determine the voltage drop across the cable. Then they can calculate the required motor terminal voltage and compare it with the voltage limit of the system to achieve a successful motor start. The starting frequency of the drive and voltage boost settings can also be determined. This simulation helps ESP specialists to evaluate the capacity of the VSD and determine whether it is large enough to support, not just the routine pumping operations, but also the system startup.

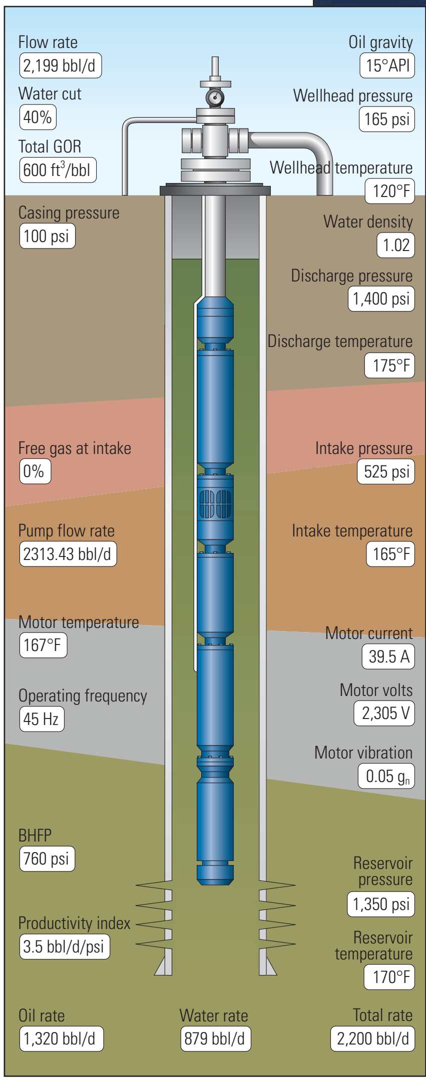
Without Filtering

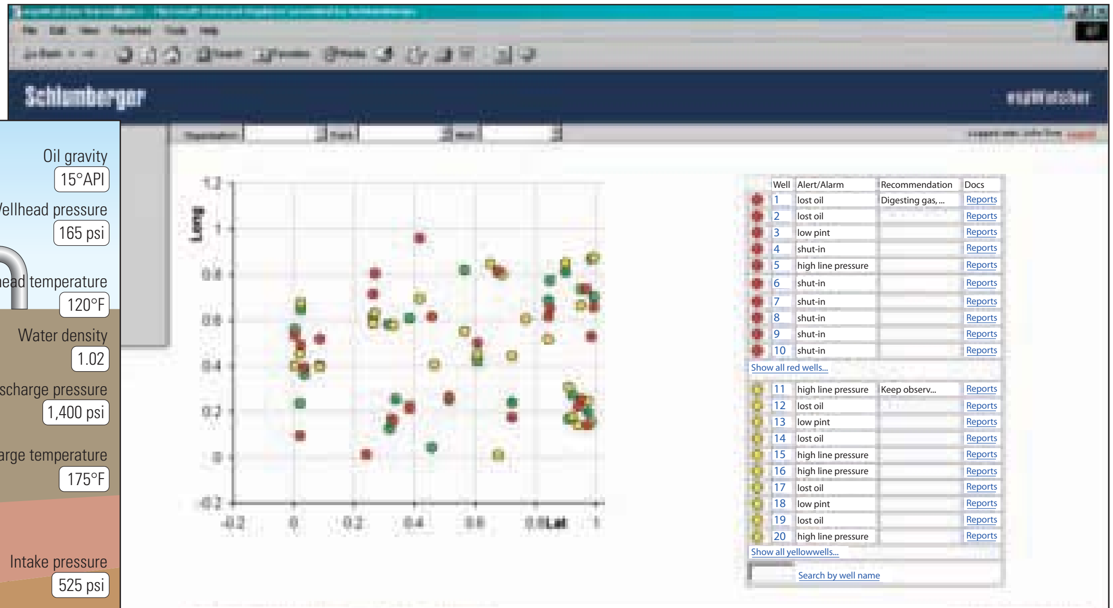


With Filtering



^ Voltage, current and harmonics. Simulation software charts typical output voltage and current waveforms of a downhole motor to show the effects of noise spikes superimposed on the waveform as a result of transient voltage harmonics (*top*). Peak harmonics levels are present at approximately 2.2 kHz and multiples thereof; thus they are seen at 4.4, 6.6 and 8.8 kHz as well. These peaks coincide with the carrier frequency of the variable-speed drive. Following analysis by EPC personnel, a load filter was recommended to save the system from potential damage caused by harmonics. After a load filter was applied, most of the noise was removed, producing a much smoother sine wave accompanied by a significant reduction in harmonics (*bottom*).





^ Remotely monitoring field performance. Secure Web access to the espWatcher system allows clients and PCoE engineers to monitor the status of a pump or field at any time. The espWatcher system can monitor numerous parameters on each particular pump (*left*). The map display on the Web interface (*right*) uses a color-coded system to quickly identify problem wells in a field. Green indicates wells that are operating within acceptable limits. Yellow shows wells that are still operating, but with some particular measurement that has deviated from acceptable limits. Red indicates wells that are shut down. ESP and reservoir engineers will usually concentrate on the yellow indicators.

Phase 2 of the development. The second well design closely mirrored the original, and the well was completed in January 2001. Flow from both wells was commingled into a single flowline through a subsea manifold, producing 30,000 bbl/d [4,767 m^3/d]. ESPs in this field average 2.3 years of run life, with the longest run life being 1,390 days.

Experience from this record-setting ESP tieback will help Shell Expro to expand opportunities for long-distance pumping from remote fields to existing infrastructure in the North Sea and elsewhere. This knowledge will help to extend the life of existing facilities and influence strategies for producing a number of reservoirs previously deemed uneconomical.

Improving Well Performance

Pump and reservoir performance invariably change over the years. Upon installation of an ESP, critical parameters such as pump speed or electric-power frequency (Hz) are set to optimize pump performance under the reservoir conditions that exist at the time. However, over time, the gas- or water cut may increase, reservoir pressure may decline, or other conditions may change, thus causing the lifting system to operate inefficiently. Not only will these factors adversely impact pump performance, some of these changes may actually damage ESPs.

Therefore, as a reservoir is produced, pump settings should be monitored and adjusted to ensure that the lifting system is operating as efficiently as possible. Most operators strive to monitor their pumps, as evidenced by stacks of pump and production records that can quickly overwhelm a desktop. Sometimes these data can overwhelm the operator as well. Most operators don't have time or resources to keep watch on the pump activity of every well in their fields.

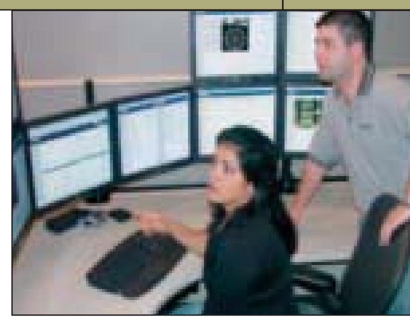
From an operator's perspective, the goal may not be to constantly monitor all pumps, but rather to determine what their optimal settings are, which settings to change, and when to change them. This is where the advanced ESP lifting services provided by the Schlumberger Production Center of Excellence (PCoE) can help operators improve efficiency in the pump and the field. PCoE surveillance and diagnostic engineers evaluate the entire ESP system to optimize production. Every component of the lifting system can be fine-tuned, from the pump to the wellbore and out to the reservoir.

The espWatcher surveillance and control system for electrical submersible pumps provides valuable information used by ESP and reservoir-diagnostics experts at the PCoE. Based on the data transmitted from the well, these experts make recommendations that can help operators boost production. The espWatcher software has the ability to monitor pump and well performance once every minute, 24 hours a day.[13] Just as important, its algorithms allow it to filter and prioritize the pump data it receives. Using this information, it can rate the status of each well as either green, yellow or red, depending on whether a well is operating within a specified performance range, operating outside of the range, or is shut down.

This Web-based system helps operators and the PCoE staff to remotely monitor the status of wells (above). When this semi-automated surveillance system detects parameters that fall

Well Number	Diagnostics	Suggested Remediation	Potential Production Increase, bbl/d
Well 1	Within safe range, to the far right	Increase Hz from 58 to 59, reduce wellhead pressure (WHP) from 185 to 100 psi	44; but 500 after installing a larger pump
Well 2	Within safe range, to the left	Increase frequency from 50 to 55 Hz	250
Well 3	Within safe range, to the left	Increase frequency from 50 to 52 Hz	75
Well 4	Within safe range, to the left	Reduce WHP from 130 to 100 psi	12
Well 5	Within safe range, to the left	Based on inflow performance relationship (IPR) curve, production potential exists	740
Well 6	Far to the left of the safe operating range	Downsize pump	Save between $1,100 and $1,900 a month in electricity
Well 7	Within safe range, to the left	Increase frequency and decrease WHP from 270 to 150 psi	410
Well 8	Within safe range, to the right	Reduce WHP from 213 to 100 psi and place on variable-speed drive; 50 to 59 Hz	130
Well 9	Within safe range, to the left	Reduce WHP from 156 to 100 psi	12
Well 10	Far to the left of the safe operating range	Increase frequency from 45 to 48.5 Hz, downsize pump to get operations in a safe range	40
Well 11	Within safe range, in the middle	Place on variable-speed drive, reduce WHP and upsize pump	570; but 1,260 after installing a larger pump
Well 12	Within safe range, to the right	Increase frequency from 50 to 58 Hz	90
Well 13	Within safe range, in the middle	Increase frequency from 53 to 58.5 Hz	210
Well 14	Within safe range, to the left	n/a	0
Well 15	Within safe range, in the middle	n/a	0

^ Tracking well problems. The evaluation table for a field in Oklahoma shows a range of diagnostics and remedial actions that could improve production or reduce operating expenses. Note that most of the wells in this field require only minor adjustments to increase output. By addressing only those wells that require changes of electrical power and pump speed, the operator could boost field production by several hundred barrels.



outside of the range specified by the operator, it sets off a yellow alarm. This alerts the PCoE staff to take a closer look at that particular well and allows personnel to focus more attention on those wells that are not performing optimally.

Instrumented wells are capable of producing constant streams of real-time data from downhole sensors and surface monitors. Much of the data are routine, and provide valuable trending information. Other data are exceptional, and point to immediate changes in parameters that warrant closer scrutiny. And some data, though transient, provide valuable snapshots of reservoir behavior.

Transient data are produced when pumps shut down or start up again. These fairly normal occurrences take place because of pump cycling, well workover or interruptions to the electrical supply caused by blackouts, brownouts or lightning strikes. Pressure measurements obtained during these transient events can provide useful information about reservoir behavior.[14] Though the pump isn't running, its sensors may still be recording the ensuing changes in the reservoir. Upon shutdown of a pump, the reservoir pressure increases, providing timely data that can be analyzed for reservoir evaluation. When the pump starts up again, the sensors obtain drawdown information on the reservoir. Transient-pressure analysis techniques are used to interpret this buildup or drawdown data and thereby determine the ability of the reservoir to produce fluid. This analysis provides information for ascertaining what, if anything, can be done to improve the reservoir's producibility. Additional details about the reservoir's outer boundary conditions can also be obtained from these data, indicating the presence of sealing faults, interference from offset production or constant pressure boundaries from pressure injection.

Based on PCoE experience, 57% of ESP wells can benefit from optimization of the lifting system, making relatively simple adjustments, such as increasing the speed of the pump to lower intake pressure and increase production. And 50% of wells can benefit from optimizing the reservoir through stimulation to reduce skin damage or through reperforating. These responses to pump and reservoir behavior can have an immense impact on well performance; according to results obtained by the PCoE, these changes can increase production by nearly 20%.

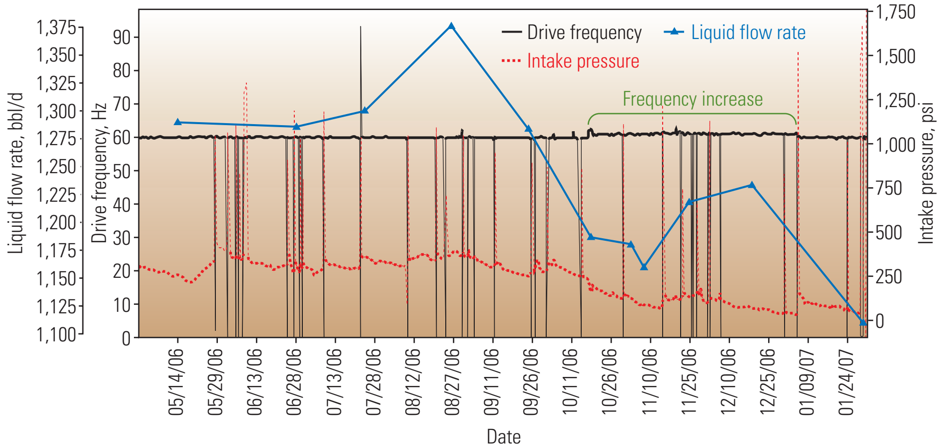
PCoE remediation recommendations include predictions regarding how much production will be increased. These predictions help operators evaluate the risk versus reward associated with acting on PCoE recommendations. The prediction also helps the PCoE track its own performance, and aids PCoE management in determining whether the remedial action was effective, and if not, what can be done to further optimize the well's performance (above).

A major challenge for the PCoE is helping operators recognize the benefits of remediation in wells that, in some cases, produce only 2 to 8% oil. For example, when the espWatcher software alerted the PCoE to increasing intake pressure in a well in Oklahoma, PCoE surveillance personnel investigated the problem and alerted the client. Seeing that the well was producing at bottomhole pressures of 300 to 400 psi [2.07 to 2.76 MPa], they recognized the potential for higher production

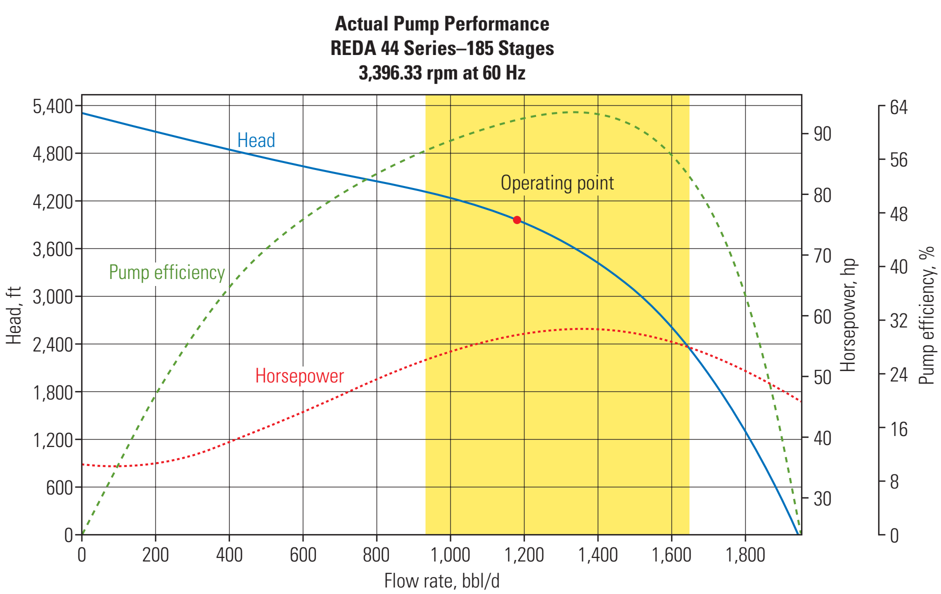
13. Bates et al, reference 6.
14. For more on using transient data to model changing reservoir conditions: Corbett C: "Advances in Real-Time Simulation," *The Leading Edge* 23, no. 8 (August 2004): 802–803, 807. Also refer to: Bradford RN, Parker M, Corbett C, Proaño E, Heim RN, Sonleitner C and Paddock D: "Construction of Geologic Models for Analysis of Real-Time Incidental Transients in a Full-Field Simulation Model," presented at the AAPG International Conference and Exhibition, Cancun, Mexico, October 26, 2004.

rates, and suggested an increase in pump speed to draw down the intake pressure and produce more fluids. PCoE engineers recommended a 1-Hz boost in electric frequency to the pump. Although this increase resulted in a lower intake pressure, it also resulted in an unexpected decrease in production rate (below).

This prompted PCoE personnel to examine the efficiency of the pump by scrutinizing the pump performance curves, which are generated individually for each pump that is installed in the field (bottom). These curves chart the relationship between pump horsepower, efficiency, flow rate and head, relative to the pump's optimal operating range.[15] Since the pump was already performing optimally, PCoE experts recommended that the operator acquire pressure-buildup data (next page, top). From the buildup analysis, PCoE reservoir engineers extrapolated reservoir pressure and calculated an average permeability of 60 mD and a skin factor of 4.[16]



^ High intake pressure. A reduction in intake pressure failed to increase production as originally expected.



^ Pump operating curves. Pump curves are custom-generated for each pump to chart the pump's ability to displace fluids. Head capacity (blue curve), pump efficiency (green dashed curve) and brake horsepower (red dotted curve) are plotted against flow rate. The most important part of this performance graph is the head-capacity curve, which charts the relationship between total dynamic head and flow capacity of a specific pump. A pump can develop only a certain amount of head for a given flow rate, and vice-versa. The yellow area on the pump curve indicates the most efficient operating range for this specific pump. In this case, the operating point (red dot) shows that, at 60 Hz , this 185-stage pump is operating within the optimum range.

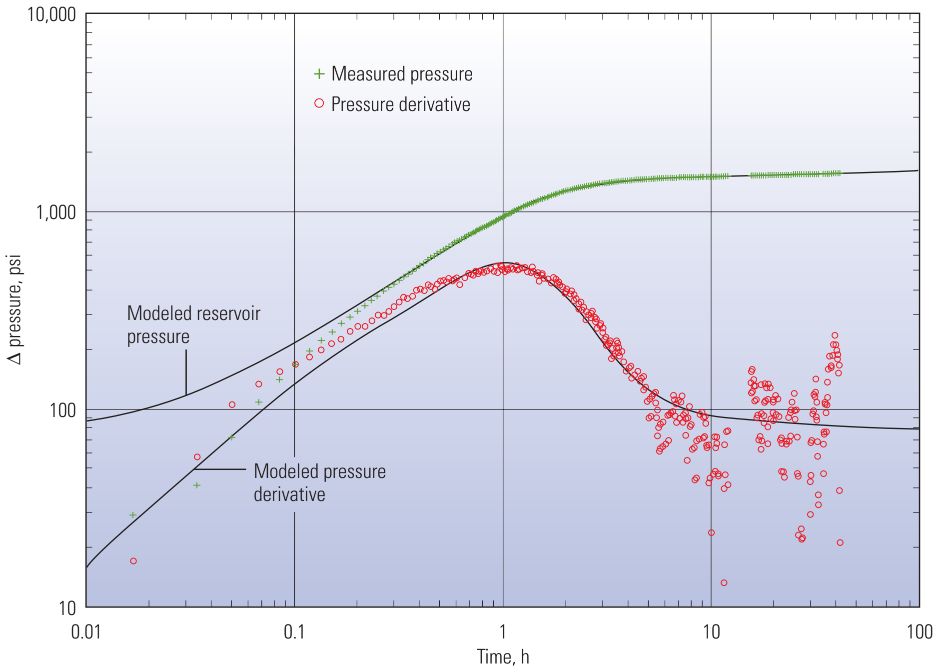
Recognizing that skin damage, with its near-wellbore pressure drop and reduced permeability, was the problem, PCoE reservoir engineers sought to quantify the impact of increased skin factor on production. The engineers first modeled the relationship between downhole pressure and flow rate. Using this model, they were able to project how production would improve if the skin damage were removed (next page, bottom). Their model showed a potential production increase, so the operator pulled the pump, acidized the well, and replaced the pump. From this remediation, the operator increased fluid production by approximately 350 bbl/d [56 m^3], from which an additional 2,550 barrels [405 m^3] of oil per year were extracted.

In addition to looking for ways to improve production, PCoE engineers seek to extend pump life and reduce downtime. PCoE engineers evaluate performance data to anticipate problems that might shorten run life, and recommend intervention as early as possible to delay onset of pump failure. Sometimes the challenge is to strike a balance between increased run life and increased production. The two are not always compatible, and operators must choose which course of action to pursue, depending on the field's production economics.

Using PCoE lifting-system diagnostic programs, ESP specialists can track pump efficiency and its degradation over time. This tracking is useful in predicting when the pumps will eventually fail. By analyzing individual pump performance and anticipating failures, PCoE engineers can notify the operator in time to evaluate the well and make the best decision for the company. In many cases, ESPs are run until they fail, at which point the operator replaces them. In other cases, economics dictate early intervention and replacement before failure, thus lessening the impact of reduced production. Tracking pump degradation also lets PCoE engineers monitor declining production, which helps operators decide when it would be most economical to intervene proactively. At the very least, timely notification by the PCoE enables operators to minimize downtime by ordering replacement pumps and scheduling workover rigs in advance.

15. Head, often used interchangeably with pressure, is generally considered to be the amount of energy required to pump a fluid to a certain height. In pump systems, engineers must contend with variations on this basic definition, and have to calculate the effects of elevation or static head, pressure head, velocity head and friction head to improve pump performance.

16. Skin refers to a zone of reduced or enhanced permeability around a wellbore, often attributed to formation damage and mud-filtrate invasion during drilling or perforating, or by well stimulation.



^ Transient-pressure diagnostic plot. The PCoE uses this chart to interpret reservoir behavior based on pressure-transient measurements. This log-log plot shows changes in measured reservoir pressure (green points) and the derivative of pressure (red points) over time. The computer-generated derivative superimposes changes in flow rate onto the pressure points. The measured and computed points are then matched against modeled performance curves (solid lines). In this model, the derivative curve trends downward, eventually flattening as pressure behavior transitions from wellbore storage to a radial-flow regime. The radial-flow portion of this curve is important for determining permeability and skin. The distance between the pressure and pressure-derivative data during radial flow is an indicator of near-wellbore damage, in which increased separation indicates greater skin damage.

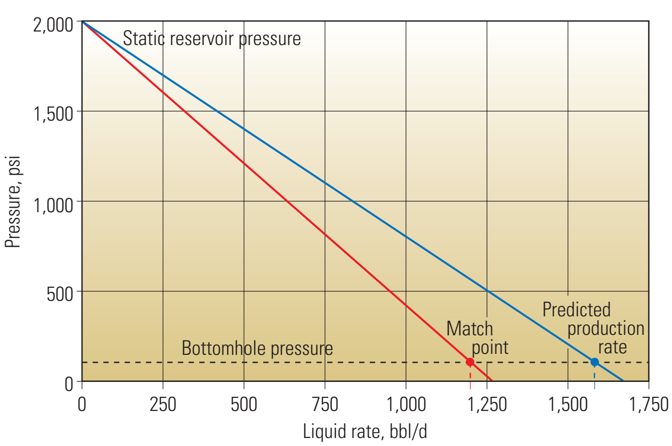
The PCoE in Oklahoma monitors more than 500 wells, from Canada and the USA to Argentina, Brazil, Colombia and Ecuador. Other such well and reservoir-monitoring centers have been created in Beijing and Aberdeen.

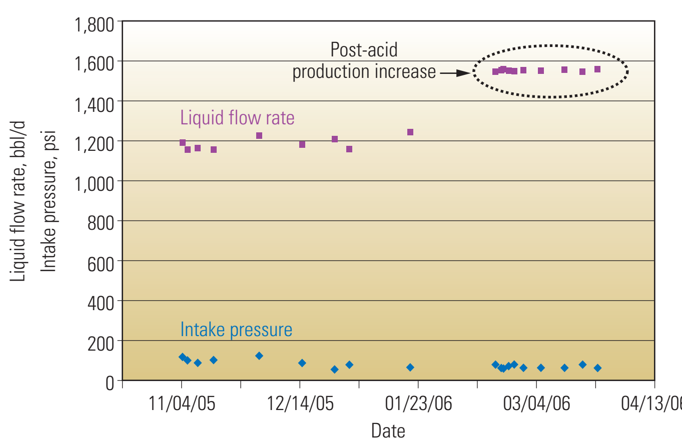
Back to the Future

In 1916, a 23-year-old Russian-born inventor named Armais Arutunoff created the first electric motor capable of operating in water and driving a pump. By 1921, he had established REDA (Russian Electric Dynamo of Arutunoff). After immigrating to the United States in 1923, Arutunoff installed the first electric submersible pumping system in the oil fields of Oklahoma.

Returning to those early Russian roots, a new generation of REDA manufacturing, engineering, field service and repair centers are now being established throughout Russia. The most recent addition is the REDA Electric Submersible Pump manufacturing facility in Tyumen. This 10,000-m^2 [107,642-ft^2] facility was opened in 2005, and is slated to produce approximately 800 ESP strings per year.

Since 1916, the REDA line of ESPs has evolved to handle high volumes of fluid, high gas/oil ratios, high temperatures and abrasive fluids in onshore and offshore applications. The engineering improvements implemented for increased reliability and efficient installation in the harsh conditions of Siberia will inevitably serve to make the next generation of ESPs even better. —MV





^ Predicting increased production. The plot of bottomhole pressure versus surface flow rate (*left*) shows how much the reservoir can yield at a given bottomhole flowing pressure. Starting with the current condition with a skin of 4, the red line is used to validate the model and match the measured intake pressure of 100 psi [0.69 MPa] with the measured flow rate of 1,200 bbl/d [191 m^3/d]. PCoE engineers can then use this model to predict the production-enhancement potential. The blue curve illustrates how a skin of 0 impacts bottomhole pressure and surface flow rate, known as the inflow performance relationship (IPR). The model predicted that if the skin is removed completely, the production potentially could be raised to approximately 1,600 bbl/d [254 m^3/d], for the same bottomhole flowing pressure. The pressure and flow-rate plot (*right*) shows that after acidizing, production was increased to 1,550 bbl/d [246 m^3/d].