# Rod Pumps in Unconventional Resource Wells

**Like all artificial lift systems, rod pumping is used to restore production when the natural drive energy of a reservoir is not strong enough to push hydrocarbons to the surface. Today, operators are applying this mature technology to enhance production from unconventional resources that were considered, until recently, economically or technically inaccessible.**

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Because of their high hydrocarbon content and impermeability, shale formations have long been considered both source rocks and sealing mechanisms in more traditional oil and gas plays. Having learned to use proven technology to exploit tight formations, the industry is now working to improve ultimate recovery from shale wells through optimal completion and production strategies.

Shale well production is characterized by high initial flow rates from natural and induced fractures accompanied by high producing pressure. However, the extremely low permeability of shale slows hydrocarbon movement through the rock to the fracture, which results in decline rates that may reach 70% within the first year (Figure 1).[1] Also as a consequence of extremely low permeability, shale formations have a limited

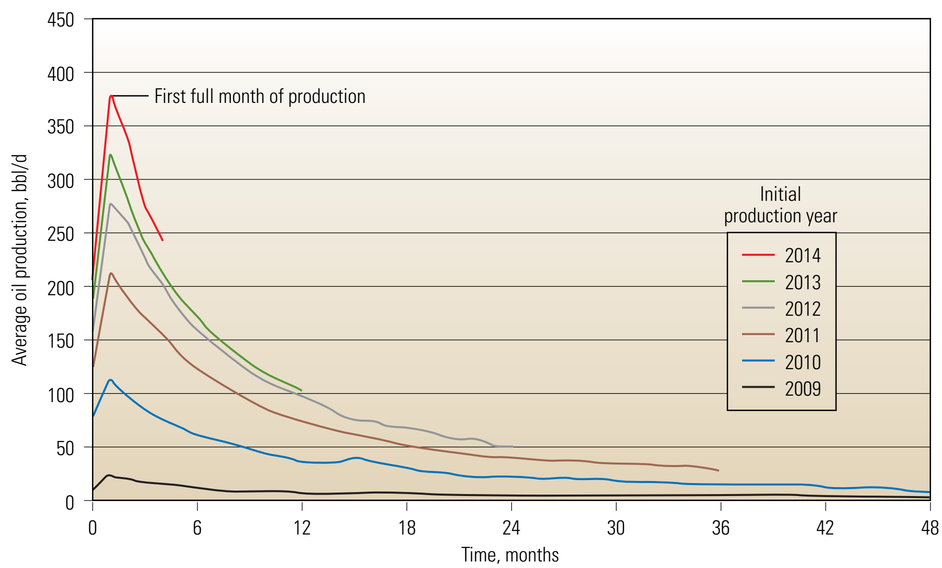


Figure 1. Typical shale resources production history. Initial high production rates, followed by rapid rate decline in the first months of production as illustrated here in the Eagle Ford Shale, typify production history in shale formations. (Adapted from the US Energy Information Administration.)

drainage radius, and their declining production is accompanied by declining sandface pressure. When the pressure falls below the bubblepoint in oil producing wells, free gas forms in the affected area of the horizontal section, and flow quickly becomes unstable, causing large variations in fluid production rates and slugging.[2]

Because of their characteristic production and pressure decline rates, most shale wells require an artificial lift (AL) system within months of first production. In these wells, operators may use any AL system that is able to produce fluids that may contain various levels of solids and entrained gas. Today, rod pumps, progressing cavity pumps, electrical submersible pumps (ESPs) and gas lift systems are all being used to boost production in unconventional wells.

In the majority of shale wells, the other AL systems—jet pumps and plunger lifts—are usually the least practical choice; the former requires a separate flow path for power fluid and the latter has a low liquid removal rate.[3] Jet pumps are applicable within only a narrow range of circumstances in unconventional resource wells and require significant capital investment.

Because fluids move slowly through shale, plunger cycle times are longer than in more permeable formations.[4] Plunger systems also depend on bottomhole pressure (BHP) to lift the plunger and the fluid column to the surface, and as BHP continues to decline in shale wells, operators may be forced to add a gas injection system to help lift the plunger to the surface.[5] Typically, plunger systems are labor intensive and require continuous operator oversight; this vigilance may be impractical in unconventional resource production strategies that include drilling a high number of wells per field.

Although gas lift systems are used in shale production, unconventional plays are typically in areas without a gas source, pipelines or other infrastructure required to efficiently deliver high-pressure gas to a large number of wells. In addition, liquid production rate changes in numerous wells may require significant field crew time to adjust gas injection rates.

In addition to exhibiting rapidly declining flow rates and pressures, shale well production typically consists of a multiphase fluid in slug flow that may include substantial amounts of sand and increasing gas content; production may also include mineral-laden, often corrosive, water that can lead to scaling. Because conditions change as the well is produced, operators must select an AL system knowing that they may have to switch system types sooner and more frequently than they do in traditional wells that have more stable flow regimes.

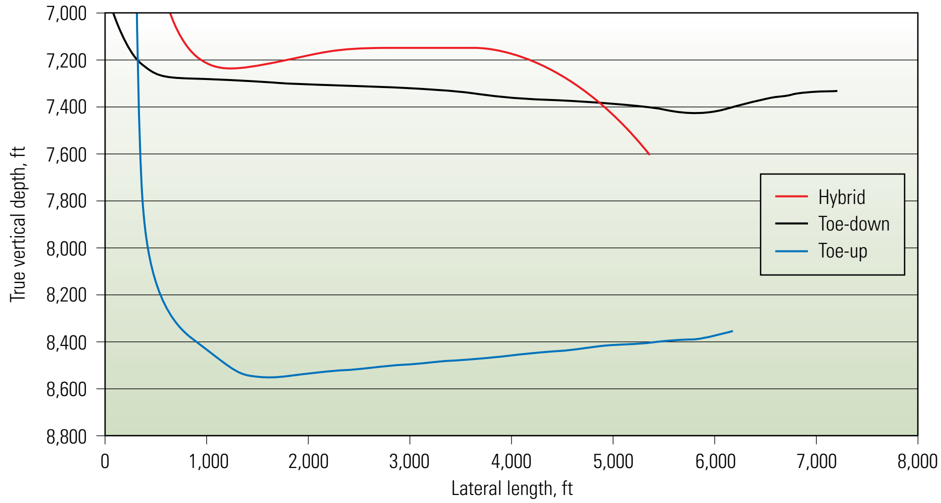


Figure 2. Common horizontal shale well profiles. Wells that have significant horizontal extensions typically include undulation and a general depth relationship between the farthest point from kickoff, or the toe, and the nearest point, or heel, of the well. When the toe is shallower than the heel, the well is called toe-up. A well is toe-down when the heel is shallower. In hybrid wells, the well path deviates in both general directions. (Adapted from Lane and Chokshi, reference 5.)

This article describes how the industry is adapting rod pump systems to shale resource wells. Case histories from various shale plays in the US demonstrate how operators are incorporating the venerable rod pump system to the new world of unconventional resources. A multiphase simulation used to describe the source of instability in fluid flow from this still little understood resource is also presented.

## Trajectory and New Rules

Hydraulic fracturing and horizontal drilling are the two technologies that have revolutionized production from unconventional resources. However, lateral wells drilled through shale sections are rarely truly horizontal. In some wells, changes in formation dip direction or rock hardness force drillers to repeatedly build and drop angle, creating undulations in the wellbore trajectory. Undulation changes the formation inflow distribution along the wellbore, and during multiphase fluid flow, gas may become trapped by accumulated liquid at low spots.[6] These liquids can create backpressure and become initiation points for slug flow.[7]

As a consequence of the bit following the updip or downdip of formations, laterals typically trend in a general elevation change consistent with that formation's rise or drop. Toe-up wells follow a formation in an updip direction; toe-down well profiles result from drilling along a downdip trend. How a toe-up or toe-down profile affects well performance is a matter of some debate (Figure 2). For instance, one study indicated that

1. Baihly JD, Malpani R, Altman R, Lindsay G and Clayton R: "Shale Gas Production Decline Trend Comparison over Time and Basins—Revisited," paper SPE 178674/URTeC 2172464, presented at the Unconventional Resources Technology Conference, San Antonio, Texas, USA, July 20–22, 2015.
   Baihly J, Altman R, Malpani R and Luo F: "Shale Gas Production Decline Trend Comparison over Time and Basins," paper SPE 135555, presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, September 19–22, 2010.
2. Norris HL III: "The Use of a Transient Multiphase Simulator to Predict and Suppress Flow Instabilities in a Horizontal Shale Oil Well," paper SPE 158500, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, October 8–10, 2012.
   When pressure of the formation gas trapped behind the liquid becomes high enough to move the liquid to the surface, it does so in a series of liquid slugs separated by gas pockets. The resulting surges can damage the formation and surface gas handling equipment.
3. Khan N, Ganzer L, Elichev V and Ali N: "An Integrated Life-Time Artificial Lift Selection Approach for Tight/Shale Oil Production," paper SPE 169833, presented at the SPE Hydrocarbon Economics and Evaluation Symposium, Houston, May 19–20, 2014.
4. Plunger cycle times are dictated by the time required for formation pressure to build in the casing annulus and liquids to accumulate in the production tubing.
5. Lane W and Chokshi R: "Considerations for Optimizing Artificial Lift in Unconventionals, paper URTeC 1921823, presented at the Unconventional Resources Technology Conference, Denver, August 25–27, 2014.
6. Bond A, Zhu D and Kamkom R: "The Effect of Well Trajectory on Horizontal Well Performance," paper SPE 104183, presented at the SPE International Oil and Gas Conference and Exhibition, Beijing, December 5–7, 2006.
7. Lane and Chokshi, reference 5.

the highest performing Barnett Shale wells in Texas, USA, were those drilled toe-up, while the same study found that the opposite configuration of toe-down performed better in Woodford Shale wells in Oklahoma, USA.[8]

The industry is just beginning to understand how shale well production is impacted by trajectory and other factors such as completion methods, operating conditions and fluid behavior. During initial high-rate, high-pressure production in shale wells, the horizontal section is filled by single-phase liquid flow. However, because of the very small drainage radius in shale wells, reservoir pressure declines rapidly until sandface pressure falls below the reservoir fluid bubblepoint. This phenomenon creates a liquid vapor flow in the horizontal section, which can lead to significant variations in fluid production rates. The effects of these rate changes are compounded by hardware used in the completion. The horizontal producing sections may include 4- to 6-in. diameter liners necessary to accommodate completion tools such as those used in hydraulic stimulations. These relatively large cross-sectional flow areas result in low fluid velocities and stratified flow that can result in gas volumes that cause slug flow.[9]

This transient process is affected by wellbore geometry, reservoir fluid properties, reservoir pressure, completion and perforation details, production rates and multiphase fluid dynamics. Schlumberger engineers recently used the OLGA dynamic multiphase flow simulator to predict wellbore instability in horizontal shale wells and to identify possible methods for suppressing production fluctuations. The simulation included a 9,500-ft [2,900-m] vertical well with a 10,000-ft [3,050-m] 4½-in. horizontal section assumed to have no inclination and 20 perforated sections. The inputs for the simulation included an initial reservoir pressure of 6,000 psi [40 MPa], a productivity index of 0.005 bbl/d/psi [0.109 $m^3$/d/MPa], a gas/oil ratio (GOR) of 1 mcf/bbl and 34 degree API oil.[10]

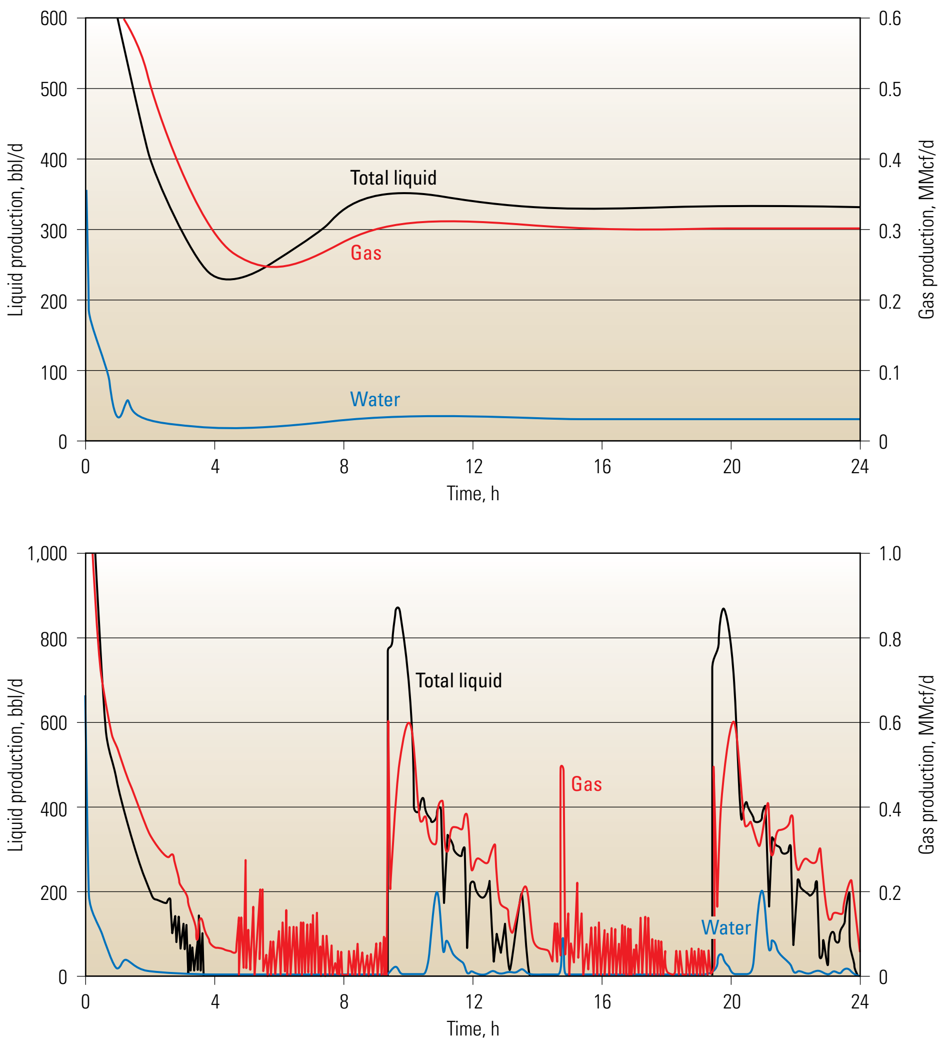


Figure 3. The dynamics of flow instabilities in horizontal hydraulically fractured wells. Simulations of a 10,000-ft TVD well that has a 10,000-ft horizontal section illustrate that a relatively high reservoir pressure of 6,000 psi (*top*) and a low gas/liquid ratio produce stable flow. However, the simulation indicates that when reservoir pressure is 4,000 psi (*bottom*) and the gas/liquid ratio is 1 Mcf/bbl [180 $m^3/m^3$], the lateral contains a liquid vapor mix that creates highly unstable flow. (Adapted from Norris, reference 2.)

While reservoir pressure remained high, the low GOR did not present a substantial threat to stable fluid flow of 313 bbl/d [50 $m^3$/d]. However, when the engineers reduced that pressure to 4,000 psi [30 MPa], liquid and gas rates oscillated, and the vertical section loaded up, or filled with fluid; production was reduced to slugs, which flowed for about three hours and occurred every 12 hours (Figure 3).

Analysts then added toe-up and toe-down well profiles to the simulations and found that both significantly exacerbated slugging and variations in liquid production rates, even at 6,000 psi reservoir pressure. In these simulations, the problem was exaggerated in the toe-down well profile because gas accumulates in the heel; in the toe-up scenario, liquid would be near the heel of the well as the gas migrated toward the toe.

In a toe-up scenario, a gas bubble accumulates at the toe and displaces the liquid at the low spot—the heel—to the vertical section before liquid can fill the horizontal section. In contrast, in a toe-down geometry, gas has a clear path to the vertical section until liquid completely fills the horizontal section. As a result, the toe-up geometry tends to produce small, frequent slugs, while the toe-down geometry tends to produce large slugs less frequently.

Simulations established that the prime source of flow instability in horizontal shale wells was low flow velocity when sandface pressures fall below the bubblepoint. Analysts concluded therefore that reducing the cross-sectional flow area of the horizontal section through the use of slimhole drilling and smaller liners, installation of a velocity string, insertion of a dead string or injection of fluids into the horizontal flow stream might remediate the slugging.[11]

### Rod Pump Systems

While the industry has learned that shale reservoirs differ from one another, production from the vast majority of shale wells occurs in stages. Initially, high bottomhole pressures provide sufficient energy for production from the stimulated zones to lift flow to the surface on its own. Within a short time, however, liquid flow rates and pressures decline, and operators must turn to an artificial lift system. No matter the type of system chosen, installation of AL systems in shale fields, which are often located outside traditional oil provinces, usually demands significant capital investments.

To optimize rate of return on investment from shale plays, operators employ strategies rooted in the certainty that shale well production rates decline during early production. Some operators select AL systems because they are able to lift the initially high production volumes that shale wells can deliver, and as production declines, exchange them for lower-rate systems.

Other operators choose to sacrifice high initial rates and instead install a system that will remain economically efficient even as production declines. Often, because rod pump systems are able to efficiently lift fluids from significant depths and to accommodate a wide range of production rates and changing well conditions, operators choose them.[12] Operators may install rod pumps at first oil or, because they function well at relatively low rates, install them later when production rates slip below those at which higher-rate systems are efficient.

One North American operator, because of low initial production rates, installed electrical submersible pumps in its shale wells at first production. But as rates fell, the ESPs became inefficient because of operating costs. The company switched to rod pump systems because they would ultimately improve the rate of return, particularly in a low oil price environment.

Operators turn to rod pumping systems for many reasons. Rod pumps have a long history in the industry, and engineers are familiar with the technology. Rod pumps are considered reliable, inexpensive and easily installed and maintained. The most common of all AL systems, rod pumps are composed of a prime mover, a surface pumping unit, a sucker rod string and downhole pump (Figure 4). The gas engine–driven or electric engine–driven prime mover transmits power to a gear reducer, which drives the surface unit. A crank arm on the surface unit turns, causing a beam to reciprocate and lift and lower a rod string attached to one end of the beam. The motion of the rod string causes traveling and standing ball valves in the downhole pump to capture fluid or to allow fluid to flow into the tubing. In some configurations, the valves are part of an insert pump—an integrated assembly that can be retrieved using the rods while leaving the production tubing in place.

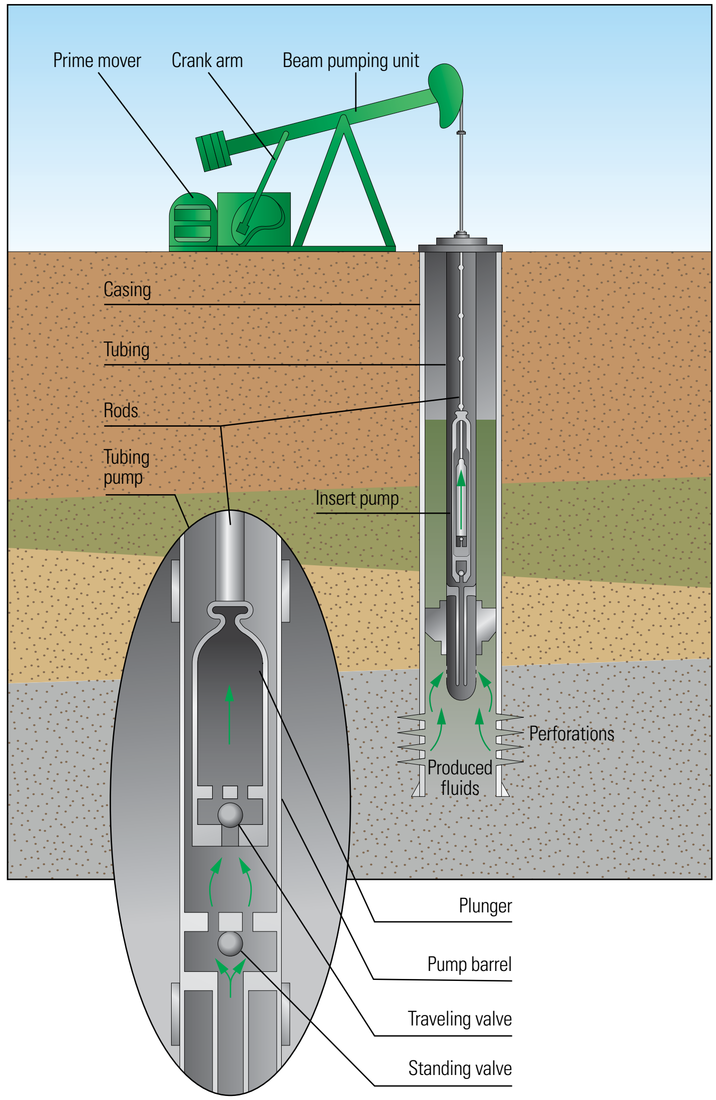


Figure 4. Beam pump system. A traveling ball valve at the end of the rod string is pushed off seat as it travels downward through the fluid column. When the traveling valve achieves maximum downward reach, and the beam is at its lowest point, the beam begins its upward movement, and the rods are pulled upward, which forces the ball of the traveling valve back onto its seat. As a result, the fluid column (green) is captured above it. As the fluid is pulled toward the surface, the reservoir pressure is greater than the pressure inside the pump chamber, which forces the standing valve ball off seat. Formation fluid (green arrows) flows through this lower valve and fills the pump chamber. When the traveling valve begins its descent, the pressure of the fluid column forces the standing valve ball to fall back onto its seat, and the cycle is repeated.

8. Miller C, Waters G and Rylander E: "Evaluation of Production Log Data from Horizontal Wells Drilled in Organic Shales," paper SPE 144326, presented at the SPE North American Unconventional Gas Conference and Exhibition, The Woodlands, Texas, June 14–16, 2011.
9. Norris, reference 2.
10. Norris, reference 2.
11. Norris, reference 2.

A velocity string is a small-diameter tubing string run inside a larger production tubing of a well as a remedial treatment to resolve liquid-loading problems. As the reservoir pressure in a well depletes, velocity may be insufficient to transport all liquids from the wellbore. In time, these liquids accumulate and impair production. Installing a velocity string reduces the flow area and increases the flow velocity to enable liquids to be carried from the wellbore.

A dead string is a length of tubing closed at the bottom and placed inside the production string. Like a velocity string, the dead string reduces flow area in the annulus formed by it and the production string and increases flow velocity.

12. Alvarez G, Ruiz R and Few J: "Shale Oil Production Challenges in Beam Pumping Being Solved with Premium Sucker Rod Designs," paper SPE 171361, presented at the SPE Artificial Lift Conference and Exhibition—North America, Houston, October 6–8, 2014.

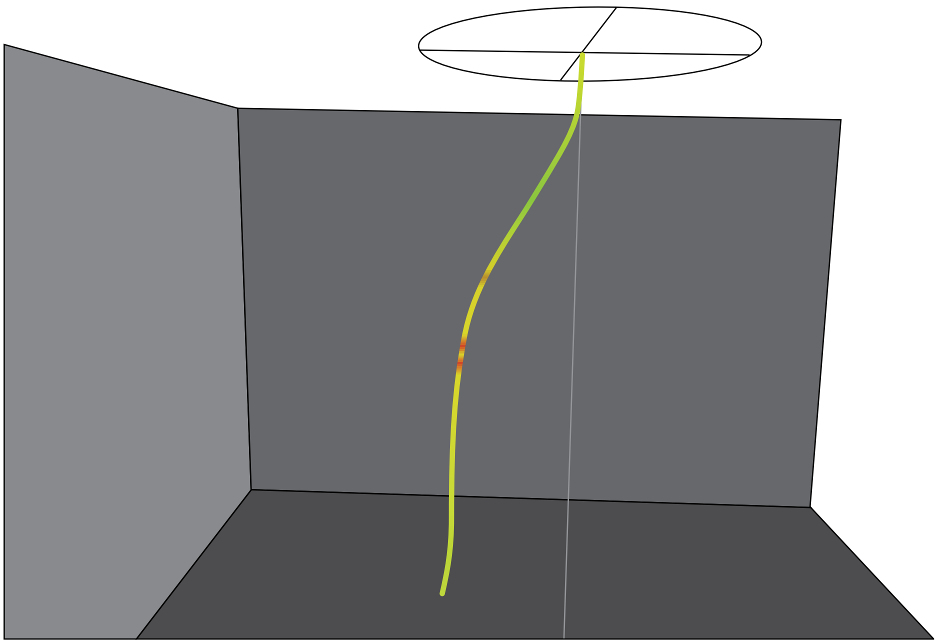

Figure 5. Visualizing tubing wear. Using 3D profile software, operators can visualize tubing wear points and severity during well planning. In this example of a basic deviated well, severity increases from the least severe (yellow) to moderate (orange) and most severe (red).

Because shale reservoirs are marked by such extremely low permeability and drainage radii, operators not only drill horizontal wells to expose as much of the reservoir to the wellbore as possible, they also drill a high number of wells per field. Drilling costs are primarily a function of time, which leads operators to drill wells as quickly as possible. This can result in unintended wellbore deviation and dogleg severity as a result of directional changes and corrections.

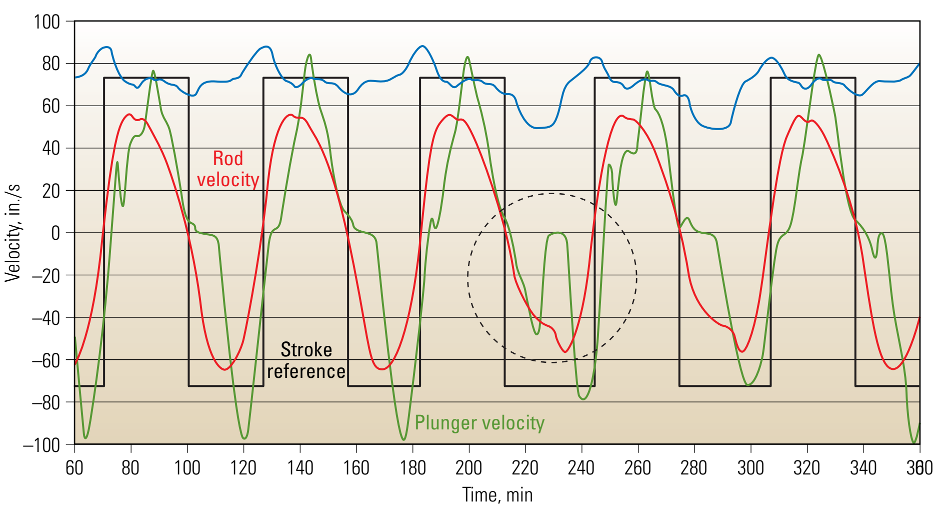


Figure 7. Evidence of gas interference from remote monitoring. Using remote monitoring, operators are able to detect possible well problems, including gas interference, by measuring surface rod and downhole plunger velocity. In this case, plunger velocity (green) drops to zero when the plunger strikes fluid about halfway through the downstroke (dashed circle). The Unistar system detects this condition (circle) and quickly responds by reducing the speed, or strokes per minute, of the pumping unit (blue) and thus surface rod velocity (red) to minimize fluid pound shock load to the rod string. (Illustration courtesy of Murphy Exploration & Production.)

To design rod strings for use in deviated wellbores, rod pump manufacturers and suppliers may use deviated-well design software to predict side loadings and dogleg severity through the use of 3D images created from operator-supplied directional surveys (Figure 5). Engineers use these images to plan the optimal rod string and pump configuration, including placement of rod guides and setting depth, type and length of rod pump to ensure extended operating life and optimal efficiency.

When one operator chose to exchange its existing AL systems for rod pumps, company engineers were concerned about the challenges to installing such systems in wellbores that included significant deviation and dogleg severity. Working with Schlumberger engineers, the operator found that the optimal depth at which to place the pump, based on pump intake pressure and fluid levels, was in a wellbore section that included a 70° inclination.

The installation design also included molded rod guides placed at strategic locations to counter the effects of dogleg severity. As a consequence of collaborative designs, the operator's wells have been on rod pump systems for more than a year and have had no rod failures while achieving targeted production rates.

**Managing Gas**

The majority of currently producing shale formations maintain sufficient energy to push formation fluids up the horizontal section of the well for most of the well life. This ability allows rod pumps to be installed in the vertical section of the well but creates challenges associated with the relative positions of the downhole pump and the perforations.

Primary among these concerns are the effects of gas interference, which results from gas displacing fluid entering the pump, which causes less than optimal production per stroke. If not managed, gas entering the pump may lead to gas locking, which is a condition in which the ball of the traveling valve cannot be unseated because gas entering the pump does not create sufficient pressure below the traveling valve to overcome the pressure created by the weight of the fluid above it. Gas interference may also be damaging to the rod system when the pump travels faster than it would when there is liquid higher in the pump barrel. This phenomenon causes the pump to land with an accelerated downward force, creating a condition known as fluid pounding, which can result in shock and vibration large enough to damage rods and surface gears.

In vertical wells, operators overcome gas interference by placing the pump below perforation depth. This creates a natural, gravity-based gas separator in which produced free gas flows upward from the perforations while the heavier fluids fill the casing-tubing annulus around the pump. However, because the pump is installed above the perforations in horizontal wells, fluid entering the pump may be foamy when the pump intake pressure is below the bubblepoint and gas/liquid ratios are high.

In shale wells, operators attach gas separators to the bottom of the downhole rod pump to isolate the pump from the direct fluid flow; separators direct the liquids into the pump and the gas away from it (Figure 6). When a relatively low pressure at that higher point in the annulus is maintained, free gas comes out of solution and flows upward, and gas-free liquids flow downward to the pump intake.

In many cases, particularly in the presence of foamy liquids, gas interference cannot be eliminated through separation, and gas consumes some portion of pump volume with every cycle of the pump. This condition can be easily discerned on dynamometer cards, which display rod load forces versus rod displacement (Figure 7).

In addition to presenting the risk of gas lock or fluid pound, gas interference reduces pump efficiency. If the pump rate is too rapid, insufficient volumes of fluid will have time to enter the wellbore around the pump, which results in pumpoff, a condition in which no liquid is being lifted.

To allow time for gas to be displaced from the pump or for formation fluids to reach the wellbore, operators adjust pump motor speed. Engineers use pumpoff controllers (POCs) to turn off prime movers for specific periods. Early versions consisted of a circular series of pins that revolved on a clock dial to complete or break circuits. In the past, the POC timing—when and for how long to turn off the unit—was set manually and determined by operators' experience in the field.

Today, POCs that have preprogrammed devices are available to collect, process and analyze data measured by load and position transducers mounted on the surface pumping unit. From a load cell mounted on the polished rod, POCs that include data about the specifics of the well are able to calculate rod load and crank arm position. Using those data, POCs determine what portion of the load is being contributed by the pump and equate that to the pump fill level, which is that percentage of the pump volume taken up by fluid.[13] When the fill level falls below a preset percentage of pump capacity, the POC sends a command to shut off the motor. After a prescribed downtime, the POC restarts the system and allows it to continue until it senses the pump is filling at below targeted levels.

Variable speed drives (VSDs) serve the same purpose as POCs but accomplish the task differently. Instead of stopping the pump when the level of liquid in the pump falls below or rises above a preset minimum and maximum fill level, VSDs regulate the motor speed to bring fill levels

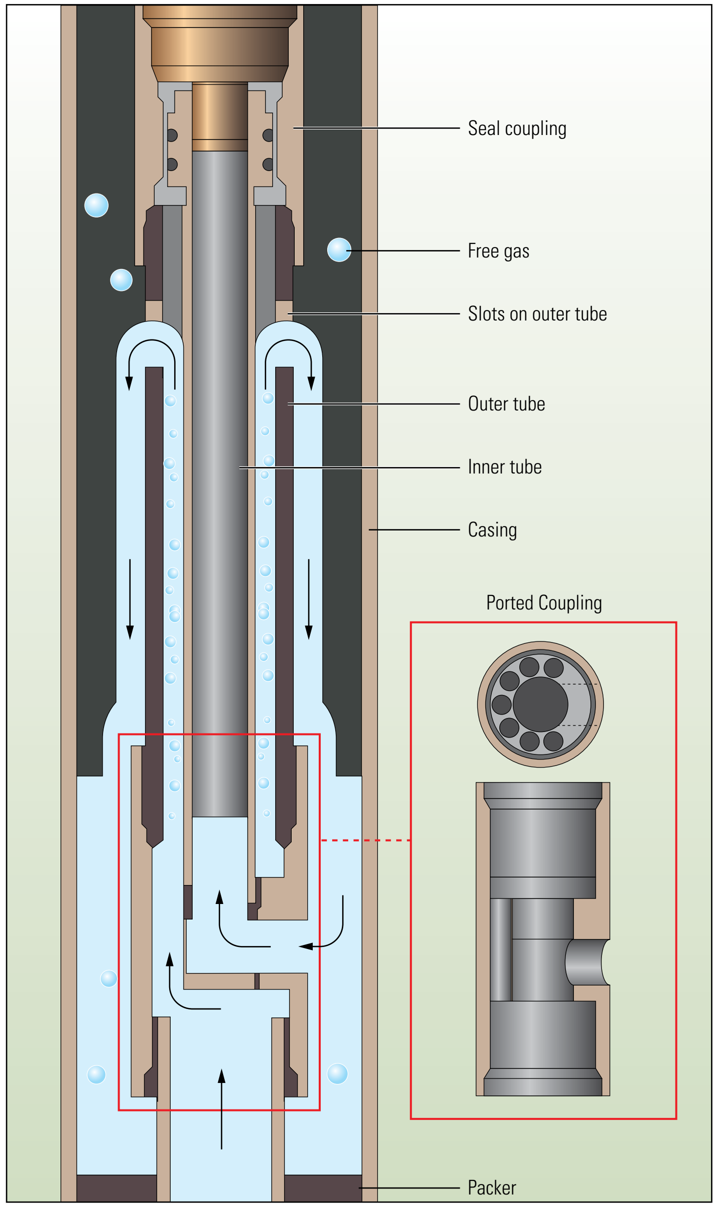


Figure 6. Packer-type gas separator. The packer-type gas separator is positioned within the tubing string directly above the packer, which forces all formation fluid to pass through the separator before it enters the pump intake. Formation fluid (black arrows) travels through the tubing string to and through the ported coupling of the separator and enters the annulus between the inner flow tube and the outer tube. The fluid then passes through the slots of the outer tube and falls back into the annulus space between the casing and the outer tube, settling on the packer. The flow path creates low-pressure turbulent flow that helps gas break out of solution. This free gas is diverted from the pump intake and travels upward through the tubing-casing annulus.

13. A polished rod is a standard alloy steel rod that has hard-surface spray metal coating; the rod supports the loads created during the pump cycle and ensures a seal through the stuffing box at the top of the well. The stuffing box, attached to the wellhead, or pumping tee, contains packing elements that form a tight seal against the polished rod. The resulting seal forms a barrier between the well and the atmosphere and diverts flow into the flowline via the pumping tee.

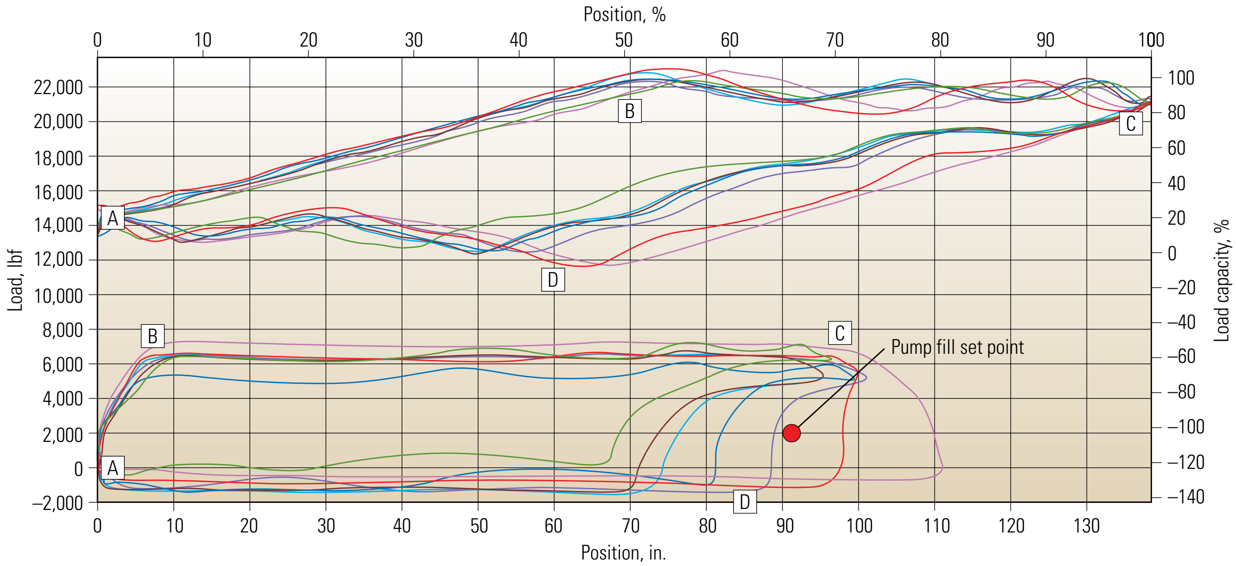


Figure 8. Using dynamometer measurements to avoid pumpoff. The surface dynamometer card is a plot of rod tension versus displacement measurements from a load cell during each rod pump cycle (*top*). Each color is a single cycle. The upward stroke of the rod string is recorded as a line from Point A to Point C through Point B, and the downward stroke is recorded as a line from Point C to Point A through Point D. At Point A, the traveling valve closes, and at Point B, the standing valve opens. At Point C, the standing valve closes, and at Point D the traveling valve opens. All surface dynamometer cards deviate from the ideal, and causes for deviation can be interpreted and corrected automatically or through intervention. Intelligent variable speed drives (VSDs) interpret the measurements taken at the surface to create downhole dynamometer cards (*bottom*). The downhole card, which, ideally, is an equilateral rectangle, provides more readily identifiable diagnostic information on current pump operating condition. When the pump plungers travels through fluid, gradual tension reduction is visible between Points C and D. A sudden reduction in load indicates the pump has traveled quickly through gas and pounded fluid. Intelligent VSD systems can interpret the shape of the line from Point C to Point D as a measure of pump fill and adjust pump speed to achieve a preprogrammed pump fill level (red dot). (Illustration courtesy of Murphy Exploration & Production.)

within a specified range (Figure 8). Variable speed drives use the pumping unit geometry and an inclinometer mounted on the beam of the pumping unit to determine the position and loads on the system. These variable speed drives also measure motor velocity and gearbox torque, which operators use to monitor unit performance and power input and output. These measurements allow operators to recognize incidents and conditions that could result in equipment damage.

Murphy Exploration & Production has more than 500 wells producing in the Eagle Ford Shale play of South Texas. Well vertical depths range from 7,000 to 12,000 ft [2,100 to 3,700 m] and laterals measure 3,000 to 8,000 ft [900 to 2,400 m]. More than 400 of the wells are produced using beam pumps.

Early in field development, engineers at Murphy chose to install rod pumps rather than a higher-rate system that they knew would eventually be replaced by rod pumping units. To maximize efficiency, they automated the systems using the Schlumberger UniStar downhole protection variable speed drive system. They also included remote pressure and temperature monitoring capabilities, stuffing box leak detection and safety shutdown capabilities.

In one example of the benefits of automation, in a well that had a 1½-in. pump set at 6,450 ft [1,970 m], average pump speed was maintained at between 3 and 2.5 strokes per minute, which rendered a pump efficiency of between 70% and 80% as pump intake pressure fluctuated from an estimated 800 to 1,200 psi [5.0 to 8.0 MPa]. Over the course of 90 days, the pump speed, pump intake pressure and oil production rates all remained within narrow ranges while producing only about 0.1 cf/d [0.003 $m^3$/d] of gas.

The operator reported benefits from automation that included savings on capital expenditures because the company was able to use smaller pump units and generators and high-efficiency motors. Automation and remote monitoring also provided the operator with equipment protection, which resulted in reduced operating expenses for workovers and part replacements. Each unit also experienced lowered peak load and reduced power consumption and required fewer routine well site maintenance visits. In addition, well performance benefited because pump speed was optimized on each stroke, the wells produced 24 hours per day with no down time and gas interference was more effectively managed.

**Rule Changes**

After a decade of drilling and producing shale formations at a frantic pace, much remains for operators and service companies to learn about the nature of these new plays. Drilling and completion engineers continue to focus on optimizing well geometry, well spacing and fracture design. But in the first flush of shale resources exploitation, developing methods to optimize production from these formations has received less attention.

Operator emphasis may change, however, as circumstances surrounding shale development evolve. Current oil prices are significantly low, and today, the most desirable shale leases have been claimed. As a consequence, funding to continue the practice of producing from extremely low-permeability reservoirs by drilling and fracturing large numbers of wells in a field may no longer be viable.

Instead, operators may seek to increase their return on investment through improved completion and production practices. That approach is made all the more practical by the fact that, according to some experts, 95% of the original shale oil in place remains in situ and much of it is accessible through wells that have already been drilled and fractured. —RvF