



SPE 80900

Coal Bed Methane Production

David A. Simpson, SPE, BP America; James F. Lea, SPE, Texas Tech University; J. C. Cox, Texas Tech University

Copyright 2003, Society of Petroleum Engineers Inc.

This paper was prepared for presentation at the SPE Production and Operations Symposium held in Oklahoma City, Oklahoma, U.S.A., 23–25 March 2003.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836 U.S.A., fax 01-972-952-9435.

Abstract

Provided that certain conditions are met, Coalbed Methane (CBM) wells have demonstrated the capacity to continue to produce a significant proportion of their peak production rates at very low reservoir pressures. Low reservoir producing pressures require low bottom-hole and surface pressures. Chief among the conditions for high production rates is being able to manage water at low surface pressure. Minimum-net-positive-suction-head considerations limit artificial-lift options. The dew point at low pressures allows large volumes of water to move as vapor—rendering mechanical separation equipment ineffective and leaving solids behind at inconvenient places. Temperature changes in buried piping condense water vapor and create both corrosion and pipe-efficiency problems. Low separator pressures preclude easy methods to remove liquid water. This paper addresses the design considerations for these low-pressure operations and related artificial lift systems

Background

Methane adsorbed to the surface of coal is a very old issue with some new commercial ramifications. This methane has made underground coalmines dangerous both from the risk of explosion and from the possibility of an oxygen-poor atmosphere. The miner's main concern with CBM has been how to get rid of it.

With the advent of active drilling for CBM in the 1980's, the problems for CBM producers have ranged from the possible inapplicability of D'Arcy's equations to having to develop techniques to remove solids from piping and surface equipment. Coal has most of the characteristics of both source rock and cap rock [3], but few of the required characteristics of reservoir rock. Consequently, we talk about "cleat porosity" and "fracture permeability" and assign largely meaningless values to force the coal to fit our mathematical and numeric models. We talk about the flow constant in the *Bureau of Mines Method of Gauging Gas Well Capacity* [1] equation

(i.e., $q = c_p (\bar{P}^2 - P_{BH}^2)^n$) as being anything but constant (in the San Juan Basin of Northern New Mexico and Southern Colorado you see the c_p term changing by 3% to 15% per month). The non-linearity (n) term is generally used as a fudge factor without any real physical explanation for selecting a value or for justifying changing the value.

The primary offshoot of the odd behavior of CBM is that the wells retain a significant portion of their peak rates down to very low reservoir pressures. For example, one well produced 10 MMCF/d when reservoir pressure was 1,200 psia and flowing bottom-hole pressure was 125 psia—if "n" is 1.0, then c_p is 0.007 MCF/(psi)². Recently the well was making over 2 MMCF/d with 110 psia reservoir pressure and 30 psia flowing bottom-hole pressure (which would make the current c_p equal to 0.179 or 25 times the peak value). The arguments around trying to describe a reason for this behavior have been much more spirited than enlightening.

Most CBM fields start with low reservoir pressure, so it is important that wells in these fields see very low producing bottom-hole pressures from first production onward. There has to be a staged approach to achieving these pressures. Surface compression is used either on the gathering system or on the wellhead (or both) to pull wellhead pressures to the lowest possible values. The choice of wellbore tubulars must include minimizing the friction drop up the wellbore. A water lifting/handling strategy must be developed to keep hydrostatic head off the coalface. One strategy that has worked in several fields has been to assign the wellbore tubing to the task of water management and the tubing/casing annulus to the task of gas production. This strategy makes selection of tubing size easier and has been effective for a considerable range of individual-well production.

Every CBM field produces some water. The water production ranges from over 300 bbl/MMCF in the northern end of the San Juan Basin to 2-6 bbl/MMCF in many other fields. Production and lift strategies need to be constructed around the requirements of a particular field. For high-water volume wells, many options are available. For more normal water rates, the need for lift is at least as great, but the options are significantly curtailed. A well that has inflow rates of 1 bbl/day above its evaporation-rate will collect over 20 feet of water per day in 7-inch casing—exerting almost 10 psi on the formation. A very few days of adding this kind of pressure to the formation will log a well off, but finding a lift method to move 1 bbl/day is difficult.

Coal is a fairly weak substance. Friability values range upward from 15 psi, so fairly small pressure drops cause the

coal to fail. Even a clean break in the coal matrix results in a release of fines. Fines are very small (on average less than 0.5 micron cross section) and very light (they are buoyant in pressurized natural gas and nearly buoyant in atmospheric air) and can migrate great distances and easily pass through filters. Coal fines are not a problem as long as they are unconsolidated, but a CBM well produces a lot of fines that can clump in the presence of a static charge or hydrocarbon liquids. Clumps of coal fines 4-8 inches in diameter are common and can clog downhole and surface piping and equipment. Tail pipes on rod pumps and jet pumps are especially susceptible to clogging with fines below the standing valve.

The CBM operator that is successful at getting the appropriate pressure to each portion of the system is then faced with several additional problems. If separator pressures are much below 15 psig, the separator won't empty into an above-ground tank or a water system. The nature of water at low pressures causes frequent phase changes that allow water (as vapor) to pass through mechanical separation equipment untouched, only to condense back to liquid in the next process. Formation water flashing to vapor will leave dissolved solids in inconvenient locations.

Minimum Net Positive Suction Head (NPSH)

Net positive suction head (NPSH) is the condition at the intake of a pumping system that compares supplied pressure (head) and friction drops in the suction piping to vapor pressure of the pumped fluid. A minimum value (NPSHr) is required so the system can function without excessive gas-related problems (the pump manufacturer may suggest a value for NPSHr but varied field conditions with free gas may require field trials to establish workable values).

Net positive suction head available (NPSHa) is a function of the fluid being pumped and pump inlet pressure:

$$NPSHa(ft) = \frac{P_{in}(psi)}{0.433(psi/ft)\gamma_{liquid}} - h_{vp}(ft) \dots\dots\dots Eq 1$$

Most pumping systems suffer when the intake fluid has too much gas compared to the liquid (which acts to increase the apparent vapor pressure).

The gas volume factor is

$$Bg=5.04 ZT/P \dots\dots\dots Eq 2$$

(which is in bbl/MSCF at downhole conditions). For instance, consider a well making 100 MSCF/d of gas (through the pump) and 10 bbl/d of water with downhole T=100°F, P=150 psia, and Z=0.9. Then Bg = 17 bbl/MSCF and q_{gas} is:

$$q_{gas} = 17 \frac{rsvr \text{ bbls}}{MSCF} (100 \text{ MSCF/d}) = 1700 \frac{rsvr \text{ bbls}}{d} \dots\dots Eq 3$$

The gas content is 1700/1710 x100 = 99% gas. This will cause gas problems for any pumping system and the gas must be separated from the liquids before a pumping system can lift this small amount of liquids.

The following correlation [23] describes the conditions where an ESP will/will-not be effective where the gas and liquid flow rates are in-situ bbl/d at intake conditions.

$$\phi = \left(\frac{666}{P_{in}} \right) \left(\frac{q_{gas}(bbl/d)}{q_{liquid}(bbl/d)} \right) \dots\dots\dots Eq 4$$

When φ > 1.0, an ESP will not perform on the head curve any longer. For the above example at 99% gas, φ= 503 which is not close to a value of a gas/liquid mixture that could be pumped according to the published head curve. For an ESP to be predicted to pump on the head curve at these conditions there would have to be a tremendous increase in either water rate or downhole pressure. However if the vapor to liquid ratio at the pump intake could be reduced to Pin/666=150/666=.23 by a high degree of gas separation such as using a sumped pump or other high gas separation technique, only then would the ESP predicted to pump on the head curve. Typically at low pressures, an ESP can tolerate 10-15% gas but can tolerate more free gas if the pressure is higher. Discussions in this paper will show field estimates of intake conditions needed for an ESP pumping system and other systems to operate.

For an ESP, an NPSHr < NPSHa allows the stages to perform on the published head curve and reduce the risk of cavitation. For a beam pump, low gas volumes at the pump intake are needed so the pump fill rate will be high enough to prevent damaging fluid pound and low efficiency. For a PCP, conditions are needed such that the volumetric efficiency is high so that high-volume gas slugs will not pass through the pump

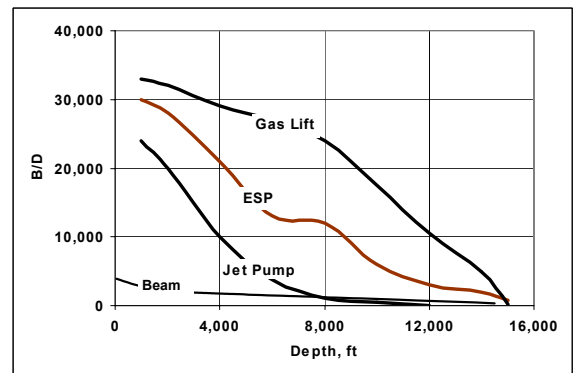


Figure 1: An approximate depth-rate application chart for systems used for CBM applications

generating heat to damage the stator and also low efficiency. A hydraulic jet pump needs sufficient intake pressure (head) to avoid cavitation in the jet diffuser. A gaslift system works better with some of the required gas from the formation, but if the gas produced is very high, then additional gaslift gas will not benefit the system, as the system would already be “naturally” gas-lifted.

Figure 1 shows approximate depth-rate capabilities for some methods of lift commonly used for CBM applications. Although some of the methods show very high capabilities in rate, the usual rates for lifting CBM wells are a less than 25 bbl/d with some a few hundred bbl/d. Many CBM wells are shallow as well, so the depth-rate figure for these methods presented shows that most CBM requirements are will under the physical capabilities of these methods, neglecting particular production problems.

Rod pump

Beam pumps are likely the most common method used to remove liquids from CBM wells. They can be used to pump liquids up the tubing and allow gas production to flow up the casing. Their ready availability and ease of operation have promoted their use in a variety of applications. Beam pump installations do have problems with gassy and solids laden production.

CBM wells will always be “gassy” in rod pump terminology (i.e., there will frequently be gas mixed with the water being pumped and the commercial product is gas so you try to maintain liquid levels as low as possible). Gas in the pump is in general managed through: (1) natural separation; (2) poor-boy separators; (3) packer separators; (4) screening devices; (5) devices to mechanically open the traveling valve to prevent gas-lock, and other devices to alleviate effects of fluid pounding; and (6) by building pumps for a high downstroke compression ratio.

Natural separation with the pump (or a diptube) set below the perforations is the preferred method of gas separation for beam pumping and other methods of lift. For beam systems there is no need for liquids to pass a motor for cooling, so if the well is drilled below the perforations, it serves well for gas separation during production. One such technique[4] is shown in Figure 2.

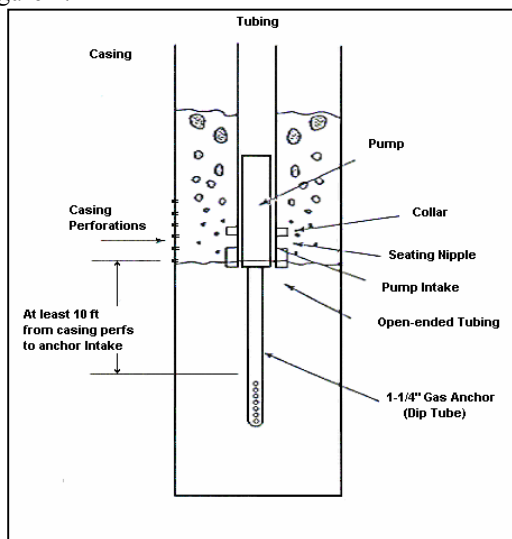


Figure 2: Poor-boy gas separator

“Poor boy” separators[5] and variations thereof rely on trying to make the fluids travel downward at less than $\approx 1/2$ ft/sec so bubbles can rise up the annulus at a higher velocity and not enter the pump. Solids can fill the bottom of the separator, but a relief valve is available to expel solids on each stroke. These separators are typically limited to production values less than 150 -200 bpd due to a high gas concentration building in and around the separator.

A packer separator[6] lets the production rise above a packer and exhaust upwardly, and then allows the liquids to fall back on the intake and gas to migrate up the casing. However solids can fall back on the packer and make it difficult to remove.

“Screening” devices[7] bring the gas-laden fluid through a fine mesh and are said to “screen” bubbles from the produc-

tion. They can also screen solids (as originally designed for) but can be defeated with paraffin or scale as can other methods. Typically screening devices have not worked well with CBM production [24] since they can quickly plug with solids and starve the pump.

If separation is not effective, there are down-hole pump modifications and options. Pumps are available for high compression ratio[8] ($\approx 50:1$ or better) Shown in Figure 3, is an example pump that has a downstroke and an upstroke compression ratio resulting in a several 100’s total compression ratio. There is some additional clearance around the hollow valve rod so sand or solids can be washed out.

Beam pumps have many features that recommend them for CBM operations. The NPSH for a beam pump is not zero. Beam pumps will not pull a vacuum if liquids are present that can flash to vapor. Very-low flowing bottom-hole pressure is often a factor in pumps gas-locking in CBM wells. There is considerable disagreement around exactly how much NPSH is required, but a value often quoted is 75-100 ft.

In general for coal bed methane applications, use a top hold-down pump for shallow wells, a full opening cage for gas and solids, a tungsten carbide seat and alloy ball for gas interference abuse, a “rag” or Martin-ring plunger for early solids-laden production and later a spray metal plunger with chrome plated barrel, a gas anchor with solids-purge valve if not setting below production, rod guides and some weight bars above pump. Do not continuously “bump” the pump for compression ratio, but instead space closely and build the pump with a long pull rod for compression ratio, such that the TV assembly can be within $1/2$ ” of the SV assembly on the downstroke.

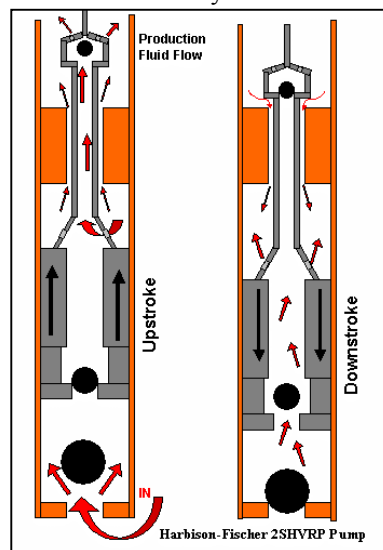


Figure 3: Dual traveling valve pump

Pump-off controllers have been very controversial in CBM. Many operators do not use pump-off controllers because the “off” cycles allow solids to settle onto the pump. On the other hand, some operators have very sophisticated pump-off control (based on installed polished-rod load sensors or pump rate-of-revolution). In general, by the time you see a pumped-off status in a CBM well, the pump is gas locked. The most effective techniques have been to either run rod pumps continuously (expecting to repair them every 6-9 months) or simple stop-clock methods that are set to maximize

total water production (e.g., run the pump 1 hour on and 2 hours off for a week, 2 hours on and 3 hours off for the next week and compare the total water produced—the experiments can take several months and monitoring should continue for the life of the well).

Progressive Cavity Pump

Introduced in 1936, the progressive cavity pump (PCP) is of simple design, and its abilities to handle solids and viscous fluids are useful for many applications.

The system is commonly used for viscous and sandy production primarily in Canada and Venezuela and also for lifting water off coal bed methane fields. Figure 1 shows one depth-rate envelope for PCP operation (with other lift methods) but specific conditions can alter this drastically.

The pump has only one moving part downhole, with no valves. The pump will not gas lock but can overheat handling gas. It can produce sandy and abrasive formation fluids and is not usually plugged by solids. PCPs do have limitations. The rubber stator may be susceptible to chemical attack, the pump stator elastomers can't handle high temperature, and is it generally limited to depths less than ≈4000-5000 ft due to fluid slippage between the rotor/stator. A cross section of the pump is shown in Fig. 4, illustrating the cavities containing fluid while pumping. The pumping rate can be easily adjusted to well conditions by changing the pump RPM.

The PCP unit consists of two main parts: 1) a moving single helical steel rotor, and 2) a stationary double-threaded helical elastomer stator. With the rotor in the stator, a series of sealed cavities are formed. As the rotor turns, the cavities progress in an upward direction. There are two main variables to consider when matching the pump to well conditions. The first

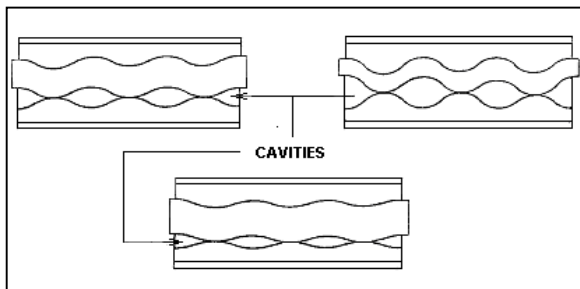


Figure 4: Progressive Cavity Pump: Large & Small Cavities [9]

is pump capacity, which is determined by the size of the cavities formed between the rotor and stator. Larger cavities produce higher flow rates at a given well depth and rate of rotation. The second is depth capability, which is determined by the number of seal lines controlled by the length of the rotor and stator. A longer rotor and stator will allow a PCP to pump from greater depths at higher given capacity rating.

PCP's are used to lift water from coal bed methane fields because they can handle solids. The main application problems are gas interference, chemical compatibility, and solids.

Most operators set PCPs high initially to avoid solids plugging and later lower them to below production for lower BHP and better gas separation. Gas separation is critical. Field operational practice has shown that about a 50-50 mix of gas and liquid can be pumped with no damage to the rotor. Also practice shows that about 60 feet of hydrostatic head over the pump is required to keep the pump charged.

PCP's can handle solids, but they perform better with soft coal fines than with abrasive frac sands. The sand can become imbedded in the stator and can then cause accelerated wear to the pumping system or seize the rotor. Sand is more of a problem in CBM as operators more frequently use fractured well completions instead of the cavitation completions that were widely used in the mid-1990's.

The actual wear in most applications occurs in the stators with 2 to 3 stators wearing before one rotor has to be replaced. Also even though well fluids for CBM applications are usually mild for the rotor, additives for scale inhibition, corrosion control, or bacteria treatments should be tested for compatibility to the stator elastomer materials.

The presence of CO₂ has been the cause of many PCP failures in CBM operations. As a general rule, CO₂ levels above 8-10% will be incompatible with PCP use. Levels below 8% might work with the proper elastomers, but success has been very limited above 4%.

For wells making high volumes of gas (1, 2, even 4 MMSCF/d) with small amounts of liquid production (~30 bbl/d), it becomes difficult to control a fluid level over the pump and in these applications PCP's have not performed well.

Gas separators should be considered in any application where the gas may be produced through the pump. The amount of gas passing through the pump has a direct effect on the pump's volumetric efficiency. There are several gas separator designs currently available, each having specific advantages and disadvantages. Although the conventional "poor boy" style separator is one of the most common in the field, it is among the least efficient. The best separation technique is to set the pump intake as far below the perforations as possible. This allows for the gas to rise into the casing annulus before reaching the pump intake.

If the pump is allowed to produce gas, the adiabatic compression (Equation 5) can quickly generate enough heat to damage the rotor elastomer. Since lubrication is reduced, friction plays a role in stator heating, but may be small compared to instantaneous compressed gas heating. See Table 1 below for the calculated PCP outlet temperatures for various conditions. The discharge temperatures predicted are very harmful to the PCP stator elastomer. If little or no liquids are being pumped to carry away the heat, the high gas compression temperatures will damage the stator in a short time.

$$T_{out} = T_{in} \left(\frac{P_{out}}{P_{in}} \right)^{\frac{k-1}{k}} \dots \dots \dots \text{Eq 5}$$

Pump-off control should be avoided with PCP's in CBM operations. The pumps have a very poor ability to cold-start with solids piled above the pump and wedged between the rotor/stator and stator damage is very likely. It is common to have to unseat the pump and add soap lubricant to get the pump to restart.

Gas Lift

Of all artificial lift methods, gas lift most closely resembles natural flow and has long been recognized as one of the most versatile artificial lift methods. Because of its versatility,

gas lift is a good candidate for removing liquids from gas wells under certain conditions.

BHP (psia)	1,000 ft	2,000 ft	3,000 ft	5,000 ft
50	495°F	653°F	760°F	913°F
75	408°F	551°F	649°F	787°F
100	351°F	485°F	576°F	705°F

Table 1: Compression temperatures for $k=1.31$, 15 psia atmospheric, $T=100^\circ\text{F}$, and 30 psia wellhead pressure

Advantages of gas lift include flexibility in design rates, wireline retrievable, handling solids, the full tubing area is open, low profile at the wellhead, one compressor can service several wells, and it can be used with multiple or slimhole wells. Disadvantages include the need for a high-pressure gas source, poor performance with high viscosity liquids, and it will not bring the wellbore producing pressure to as low a value as most artificial lift and pumping systems. Gaslift will significantly lighten the gradient in the tubing by primarily reducing the average density of the water/gas mixture and by a velocity effect of the bubbles “scrubbing” the liquids. However, no matter how well designed for oil wells, or CBM wells, the producing bottom hole pressure typically cannot be lowered to values achievable for most other pumping systems. Therefore for CBM wells handling solids is a plus, but the inability to bring the formation to a low pressure is a negative. Before considering gas lift, the achievable producing bottom hole pressure must be evaluated to see if it will be low enough to produce at the rates desired.

Gas lift of gas wells can be thought of in the conventional manner of adding gas to establish a minimum or economical gradient in the tubing. However it can also be thought of as adding enough gas to the tubing to keep the velocity above a “critical rate” so liquid loading will not occur [10]. Stephenson[11] et al., present a study of gas lift compared to other lift methods to de-water gas wells with results of the final gas lift installation.

Johnson[12] et al., present a study of using gas lift for de-watering a CBM field. Johnson points out that single-point injection down the tubing with returns up the annulus is a common clean-up method in the Black Warrior Basin as it is in other CBM fields. A conventional gas lift system is described with gas lift valves in 1 1/4” tubing, with liquid and gaslift gas returns up 4 1/2” tubing and reservoir gas production up 7” casing. A system of reeled tubing to inject gas into mandrels in tubing, with gas production up the tubing/casing annulus is described and thought to be a successful operation. This system was at times operated intermittently and brought on when pressures increased. Thrash[13], in an older paper, describes gas lift with gas down a small string inside tubing, and the completions described would seem possible for CBM production if gas were allowed to flow the tubing/casing annulus.

Boswell[14] et al., describes a system of gas lift bringing injection gas down the annulus and returns up the tubing. This is a simple de-watering completion, but it would, again have to be evaluated to see what producing pressures could be obtained. For fairly high produced-liquid rates, the producing pressure at the bottom of the tubing could be too high for CBM applications.

Gas lift is a flexible method of lift that is not troubled with gas interference or solids for the most part. However it will not bring the producing pressure down as far as a pump system can. It is not troubled with solids wear and gas interference to a great degree. The NPSHr for gas lift can be estimated using Nodal Analysis (TM of Schlumberger). For instance with water from 2,000’ in 2” tubing, the lowest producing bottom hole pressure using gaslift is around 350 psi for 1000 bwpd and around 275 psi for 500 bwpd.

Jet Pumps

Downhole jet pumps have been used in oil fields since the 1950’s, but successful use in gas wells is very recent. Jet pumps use a high-pressure liquid pumped through set of convergent/divergent nozzles (Figure 5) to transfer momentum to formation liquids. The power fluid in oil fields is stock-tank oil, and in gas fields it is produced water.

Traditional jet pumps are seated in a packer. Power liquid is pumped down the tubing/casing annulus and the combined stream is returned up the tubing. These pumps are rarely effective in gas wells because the internal ports are too small for low-density compressible flow. There have been attempts to use gas as power fluid with large-capacity pumps in CBM fields, which have been unsuccessful largely due to solids plugging.

Tubing pumps are more suited to gas fields. With these pumps, two tubing strings are run (either dual or concentric strings) without a packer. This allows gas production up the tubing/casing annulus and liquid production through the jet pump. Tubing pumps can be configured to move up to about 75 bbl/day. Liquid production less than about 15 bbl/day is difficult to configure because of cavitation concerns.

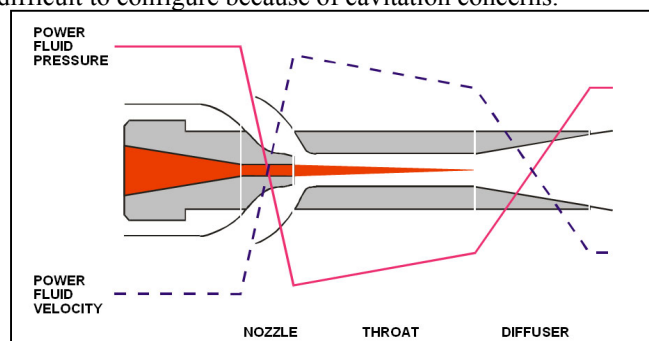


Figure 5: Jet pump schematic (courtesy, Weatherford)

Surface pressures over 3,000 psig plus hydrostatic pressure (0.433 psi/ft for water) are required for power fluid. Wellhead pressure plus hydrostatic head determines exhaust pressure. The pressure drop across the nozzle provides motive power.

Total head developed is the difference between flowing bottom-hole pressure and exhaust pressure. A “compression ratio” (i.e., exhaust pressure divided by bottom-hole pressure) more than 5-7 will starve the throat and cause cavitation. Cavitation damage to the throat disrupts the power-fluid flow and quickly destroys the pump’s ability to move suction fluid. Six ratios in a 1,200 ft well sets the minimum NPSHr at 200 ft (86 psig) plus the wellhead pressure. An NPSHr this high is inconsistent with required bottom-hole pressure in most CBM wells, and jet pumps have only been successful early in the life of the wells when there were still significant pressures.

Jet pumps have a poor ability to handle coal fines. Flow over control surfaces in the pump can generate enough static electricity to start coal fines clumping. The ports are so small that clumps rapidly stop formation-fluids from flowing into the pump and initiate cavitation.

Pump-off control is quite easy with jet pumps—when the surface-pump discharge pressure decreases, the jet-pump discharge has become gassy. The most effective pump-off control is a “constant-pressure” valve that recycles a portion of the surface-pump flow to maintain a constant power-gas pressure at the jet-pump. For surface pumps with auto-start ability, a turbine meter can be used on the recycle volume to shut the process down when the recycle gets too high. A stop-clock can be used to restart the process.

Compression

Compression contributes to artificial lift in three ways: (1) lowering surface pressures lowers flowing bottom-hole pressure and increases inflow rate; (2) increasing gas velocity improves its ability to carry liquid water to surface; and (3) at lower pressures, natural gas can carry more water as water vapor. Every successful CBM operation includes a considerable amount of compression.

The predominate compression technologies used in CBM are reciprocating compressors and flooded screw compressors. Other technologies such as liquid-ring, centrifugal, and dry screws have found niches in various CBM fields, but their use is not widespread.

Reciprocating compressors use a piston moving within a cylinder to pull gas into the compression chamber and then raise the gas pressure to the required level when the piston reverses. Recips are the most common compressors in oil & gas operations and operators are extremely familiar with their operation and maintenance. They are limited to about 4-5 compression ratios per stage by acceptable forces on the piston rods and by allowable gas temperatures. Single-stage recips are the most efficient compression technology available. Two and three stage machines are progressively less efficient. A recip can be designed to move any particular volume from a given suction pressure to a specific discharge pressure. Proper performance is only achieved when the suction pressure is within $\pm 5\%$ (in psia) of design conditions. This narrow suction range makes efficient use of recips on well sites very difficult since wellhead pressure swings with water level in the wellbore. The narrow suction range is usually not a problem on booster or mainline compressor stations because these stations are generally designed for a narrow suction range.

Flooded screw compressors have a pair of helical screws that mesh with each other as they rotate to compress gas. Oil is flooded into the compressor chamber to seal around the rotors, prevent metal-to-metal contact between the rotors, lubricate metal parts, and remove the heat of compression. Moving the oil requires some power, and a flooded screw is about as efficient as a two-stage recip. Since screws don't have rods and since oil is a much more effective heat-transfer medium than gas, 10-12 ratios are a reasonable performance expectation. Each manufacturer specifies a maximum suction pressure for their machine, but the flooded screws work very well anywhere below that maximum.

Compression can be used to move 4-6 bbl/day of water depending on bottom-hole pressure (the lower the pressure, the more water you can move with a compressor).

Pump-off control is not an issue with compression since compressors do not have a minimum NPSHr and actually have better success when they don't have to deal with liquids. Too much liquid above the formation can seal the formation-gas away from the compressor suction and prevent inflow. Because of this, compression is the least effective lift technique for recovering from excessive liquid inflow. Water transients have been responsible for taking compressed CBM wells from very high gas rates to no flow in very short periods of time (recovering from these transients generally requires installation of other lift techniques).

Eductors

Eductors are classified as thermocompressors and are in the same family as jet pumps, sand blasters, and air ejectors. They use a high-pressure fluid (either gas or liquid) for motive power. Eductors using gas can impart up to two compression ratios, using liquid they can impart more ratios.

One successful configuration has been to use a flooded screw compressor to pull the tubing/casing annulus down to 8-10 psig. A portion of the gas discharged by the compressor is used to drive an eductor to pull the tubing down to 1-5 psig. The exhaust of the eductor is combined with the casing gas and sent back to the compressor. An eductor sized to provide adequate velocity in 2-3/8" tubing (to stay above the Turner[10] required critical gas unloading rate, Equation 5) requires less than 20 hp. This configuration has maintained nearly constant liquid levels for years without any additional lift.

$$q_{MMCF/d,critical} = \frac{17.197PA(67 - 0.0031P)^{1/4}}{TZ(0.0031P)^{1/2}} \dots\dots\dots \text{Eq 5}$$

Like compression, eductors don't have a minimum NPSHr and are capable of moving 6-10 bbl/day.

Electric Submersible Pumps

Electric Submersible Pumps (ESP's) are typically reserved for applications where the produced flow is primarily liquid at a high inflow rate. Significant gas entering an electrical pump can cause gas interference if the ESP installation is not designed properly. Free gas dramatically reduces the head produced by an ESP, and may prevent the pumped liquid from reaching the surface. In gas reservoirs that produce high volumes of liquids, ESP installations can be designed to effectively remove the liquids from the wells while allowing the gas to flow freely to the surface.

The ESP system[16] consists of a downhole motor connected to a seal-section which in turn is attached to a centrifugal pump. A high-voltage electric cable connects the motor to the surface where either a high voltage transformer or a VSD (Variable Speed Drive) transformer supplies the electrical power. It is imperative that the motor be cooled by the produced fluid passing its outer casing. In the event that large quantities of gas pass the motor, the heat transfer from the motor to the produced fluid will be drastically reduced, potentially causing motor damage. The seal section houses a pump thrust bearing and restricts the well bore fluids from entering

the motor. The pump has an intake where the fluid enters the pump at the bottom of the pump. The intake can be replaced by a rotary gas separator, which separates gas to the annulus while nearly all liquid enters the pump. The pump itself consists of a stack of impeller/diffuser combinations that generate head and pressure. The amount of head required to bring the liquids to surface dictates the numbers of impeller/diffuser pairs and the flow rate required determines what type of stages to use.

For shallow low-rate coal bed methane wells, the industry has adapted small water-well pumps and motors that are fairly inexpensive, normally with plastic stages or stamped stainless steel stages. The units last for a while and then are discarded when they fail or wear and are not rebuilt. Single pumps are used and there is no way to tandem the discardable pump equipment. For deeper, higher-rate wells, oil-well equipment is used, often using the special trim required to handle solids or sand.

Solids, depending on their shape and hardness, can cause excessive radial wear in the top and bottom of the pump, which can cause leakage across packing glands. Wear can cause excessive stage downthrust wear and even cut through the impeller. Erosive wear of particles passing through the pump will reduce the stage head generation. Manufacturer's combat solids problems [9] by using stabilizer bearings in the pump, coated stages and impellers, special materials for impellers and diffusers in the pump, fixed stages (compression pump) to reduce stage/impeller wear, and use of special hardened modules to carry thrust to eliminate wear. Also there are screens, filters, and swirling devices to eliminate solids from entering the pump. Operations are easier if solids can be carried through the pump so periodic bailing operations are not necessary as would be required if solids are filtered at the pump intake.

In summary, ESP installations are expensive and usually consume more power than a beam pump system for the same rates. Of course they should be compared only when the rates are well within the good operational ranges for both the beam and ESP systems. In addition, the efficiency of an ESP system is significantly reduced (similarly for a beam system and other systems excluding gas lift) when gas is allowed to enter the pump. These shortcomings limit the use of ESP's for gas well de-watering applications. Also ESP's show accelerated wear in the presence of solids and this is a minus when using ESP's with CBM applications. As mentioned, the solids that do the most damage are often flow-back of fracturing sands as opposed to coal fines. The industry has made economical use of water-well discardable pumps to depths of about 1000 ft and low rates. For higher rates and deeper depths, typical oil field grade ESP's are used with gas handling or separation methods and often trim to handle solids is added.

The NPSH of an ESP in all liquid is low and may be only 20-30 psi (46-70 ft), but with realistic expectations for gas inflow in tends to be well over 30 psi. When gas is present, a larger pressure is required at intake to allow the pump to perform near its head curve. If the gradient is much below 0.28 lb/ft, the pump will probably see gas interference regardless of the amount of head (due to the vapor pressure of liquid that light).

Pump-off control should generally be avoided with ESPs in CBM because solids will quickly settle out of the static discharge stream and can stick a pump. Any ESP in CBM should have an easy way to monitor current draw, and dataloggers have been used with good results.

Dew Point

At normal gas-field operating pressures, the amount of water that can move as water-vapor is small. At the pressures CBM requires, this is no longer true. As figure 6 shows, with 100°F water at 30 psig bottom-hole conditions you can move 6 bbl/MMCF of water as vapor. Since most CBM wells produce less than 6 bbl/MMCF, just providing low pressures can often be an adequate artificial-lift technique.

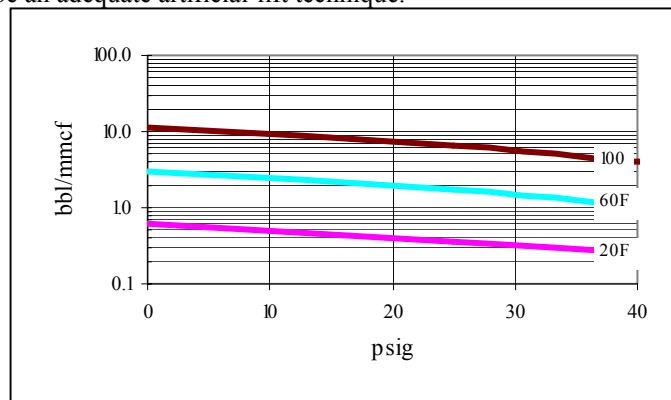


Figure 6: Water-carrying capacity of natural gas

Pressure or temperature drops up the tubulars can shift the position on figure 6 and cause liquid water to flash or water vapor to condense. Neither of these conditions is particularly stable and both cause significant production problems.

Consequences of flashing water

Formation water typically has something on the order of 10,000 mg/l of total dissolved solids (TDS). If you flash a barrel of this water, you will leave 3.5 pounds of solids somewhere. Since phase-change is not instantaneous, liquid water will generally stay liquid for a time after the phase envelope would indicate that it should be vapor. When the water experiences a large pressure drop across a short distance (e.g., the wellhead piping configuration can cause a 0.5 psi drop across 4 feet), the water drops too far outside the phase envelope and flashes—leaving behind the solids. Phase-change solids accumulate in control valves, tortuous piping, and separator mist pads. The nature of the solids deposition is a function of the solids that are dissolved.

Frequently, sodium salt (NaCl) makes up a significant portion of the TDS. Salt blocks form quickly in control valves or mist pads. As the salt collects, the pressure drop increases. As the pressure drop increases, even more salt collects. Salt can completely close piping. If salt forms in the valves of a reciprocating compressor it starves the cylinder and significantly increases the compression ratios (increasing cylinder temperature and rod loading). In screw compressors, salt can collect inside the compressor frame and increase rotor wear. Salt is soluble in hot water, but not quickly. Small accumulations can be treated with large quantities of hot water (e.g., up to 20 bbl of 180°F water is required to dissolve 1 lb of salt). Disassembling piping and breaking the salt out of the lines

mechanically is generally required to remove large accumulations. Frequent pressure surveys are required to find salt accumulations before they become large.

When the formation water is buffered with bicarbonate (HCO_3) and has sodium salt, phase change can form nahcolite (NaHCO_3), which is very hard and not soluble in water. Strong acid or mechanical scraping is required to remove nahcolite.

Different contaminants in formation water form other solids aggregations—none of which are desirable. So far no one has developed a preventive approach to dealing with phase-change solids. Scale-prevention chemicals add mass to the stream and when the water eventually flashes, the additional mass remains behind. Some operators have tried injecting water to wash solids out of lines as they form. Since cold water has a limited ability to dissolve a limited number of the types of solids that can form, this technique has been less than totally effective.

Condensation in piping

Condensing water in vertical pipes significantly increases the total pressure drop up the well. A downhole pressure survey clearly shows where there is condensation—the pressure gradient can nearly equal a water gradient in the condensation region, which can be vertically above a gas gradient (Figure 7).

Techniques to reduce condensation downhole have included insulated tubing material and heating the tubing with

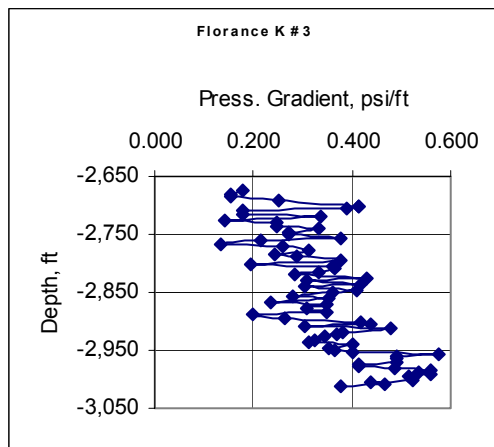


Figure 7: Downhole pressure gradient

electrical coils. There is not enough data on either of these techniques to assess their effectiveness or general applicability in CBM.

Condensing water in horizontal piping collects in low points. This water reduces the effective pipe diameter, increases pressure drop, and provides a suitable environment for accelerated corrosion. You can't prevent water from condensing as gas reaches ground temperature, so you have to design piping systems to allow removal of standing water. Pigging facilities are very effective at removing water, but not all lines were designed to be pigged. Retrofitting pigging facilities can be difficult and expensive.

Gas velocities above 13 ft/sec have proven effective at keeping water from collecting in horizontal pipes. Pipes tending toward vertical require somewhat higher velocities. Some

operators install a single large flow line across location from the wellhead to the separator. When the large line is dry, it provides good pressure performance. When the large line fills with water, the pressure drop can become unacceptable both because of reduced flow area and because the gas has to do work to shift the surface of the water. The traditional way to remove water from wellsite flow lines is to blow the lines to atmosphere to sweep the line. With large flow lines this works until the liquid level falls enough to drop the gas velocity too low to have any sweep efficiency. At that point the gas just blows over the top of the water without moving any water. A more effective design has been to lay multiple lines from the wellhead to the separator. Together the lines provide similar flow area to one large line, but you have the option of sending the entire well stream down any one line to sweep liquids from it.

Water removal from production equipment

Low wellhead pressures translate to even lower separator pressures. An API standard 400 bbl tank is 20 ft tall so a dump line into its top would require separator pressure to be at least 12 psig (to account for friction drop). Water-gathering lines tend to have even higher backpressure. Many jurisdictions allow CBM operations to surface-discharge produced water. In these operations, there still needs to be enough pressure to operate dump valves and to overcome friction drops in the piping to collection points.

When a dump valve opens and the downstream pressure is higher than separator pressure then either a check valve will stay shut or the downstream fluid will flow back into the separator—neither situation is effective at removing water from the separator. Underground tanks can be used, but they tend to be fairly small and have to be emptied frequently which increases cost and raises the risk of produced-water spills.

Options for removing water from production equipment

Blowcases provide an effective technique for shifting water from a low-pressure separator. A blowcase is a vessel that has two distinctly different modes of operation. In the "fill" mode, the separator drain is connected to the blowcase and the blowcase is vented to the separator. During fill, both vessels are at the required low pressure. When a level switch is activated, the blowcase goes to "drain" mode. During the transition to drain, the blowcase vent shuts, a power-gas supply valve opens, the blowcase fill/drain line is isolated from the separator (usually with a check valve), and a blowcase dump valve opens. This allows a high-pressure source (such as the compressor discharge) to empty the blowcase to a tank or a gathering system. When the level switch resets, the dump and power-gas supply valves close, and the vent opens to equalize the pressure and allow water to flow from the separator into the blowcase. Blowcases have proven to be effective in CBM, but have been susceptible to plugging from the collection of coal fines so any blowcase installed on a CBM well should have cleanout ports.

Pumps can also be used to move water from separators. Since the accumulation of liquid in a separator is intermittent, any pump used must be able to start and stop automatically. Typically this is a low-head application that must take liquid from under 10 psig up to less than 100 psig. The most effective pump technology in this range has tended to be diaphragm and centrifugal. Positive-displacement pumps are a poor

choice in any environment where solids accumulation or freezing can dead-end the pump and build excessive pressure.

The local environment often limits choices of prime movers for a pump. Electric motors are often the best choice if there is adequate electrical power available. Gas diaphragm pumps have proven effective in many situations, but the exhaust gas can be a significant cost and pollution source. Natural-gas fueled engines have not proven to be very satisfactory because auto-start capability has been difficult to implement in 3-5 hp sizes.

Often wellsite separation causes more problems than it cures. Several CBM operations rely on central compression and omit wellsite separators. This technique increases the amount of water that can collect in gathering lines, but is very effective if the gathering line can be regularly pigged. Removing wellsite separators is not a good idea with wellhead compressors.

Conclusion

CBM can remain profitable at reservoir pressures much lower than the economic abandonment pressure in a conventional gas reservoir. These low pressures can create an environment that can be very difficult, but the extra work is often justified by the field's income.

Solutions to problems in CBM often cause new problems that are at least as bad as original problem. Successful CBM operations have enough flexibility built into equipment design to allow creative people to find solutions. For example, recently a rod-pumped well salted up in the tubing/casing annulus and the operator was able to redirect valving to send the rod-pump discharge down the annulus to break the salt bridge. The salt bridge broke, but this technique put a significant amount of water into the wellsite fuel-gas system and the operator spent several hours restarting engines and drying out control gas lines. This technique was not anticipated by anyone, but the valves, interconnects, and cross-connects that the wellsite design included allowed this procedure (and the subsequent drying evolution).

Techniques that worked in the past may not continue to work at the next set of downhole conditions. For example, soap was an important deliquification tool when reservoir pressures were over 200 psig. Somewhere under 200 psig, the soap stopped activating (i.e., the soap would dissolve without ever foaming) and it gave no relief from water accumulation. Lab testing with surfactants can save money vs. expensive trials.

The essential point is that you must design your operation with a definite strategy in mind, and the strategy must include enough flexibility to allow for emerging technologies, new ideas, and new problems.

A lift strategy is crucial to an overall strategy. Various types of lift perform differently in CBM (really at low bottom hole pressure, moderate water rate, and a solids-rich environment). The techniques reviewed in this paper have been:

	Typical Capacity (BBL/day)	NPSHr (ft)	Failure method
Eductor	6-10	0	Plug off
Compressor	4-6	0	Plug off
PCP	4-600+	60-100	Heat of Compression
Beam Pump	20-500+	75-100	Gas Lock
Gas Lift	1,000+	200-500	Erosion
Jet Pump	10-45+	450-1,000	Cavitation
ESP	70-1,000+	150-2000	Cavitation

Table 2: Summary

Nomenclature

A = cross-section of pipe open to flow, in^2

bbl = Standard oil-field Barrel (42 gallons or 0.159 m^3)

c_p = Back Pressure constant (MCFd/psi²)

B_g = Formation volume factor (BBL/MACF)

D = Inside diameter of a pipe (inches)

h_{vp} = Vapor pressure (ft)

k = Isentropic exponent (no units)

L = Length of a pipe (miles)

MCF/d = Thousands of Standard Cubic Feet per day (28.3 m^3/day)

$MMCF/d$ = Millions of Standard Cubic feet per day (28,317 m^3/day)

n = Non-linearity term in back-pressure gas flow equation

\bar{P} = Average Reservoir Pressure (psia)

P_{bh} = Flowing bottomhole pressure (psia)

P_{dn} = Downstream pressure on a pipe (psia)

P_i = Initial Reservoir Pressure (psia)

P_{in} = Suction Pressure (psia)

P_{out} = Discharge Pressure (psia)

P_s = Standard Pressure (psia)

q_{gas} = gas flow rate, bbl/day or MMSCF/d as indicated

T_{in} = Suction temperature (R)

T_{out} = Discharge temperature (R)

Z = gas compressibility factor, dimensionless

γ_{liq} = Specific Gravity (relative to water)

ϕ = ESP performance correlation

References

- Stephens, Maynard M.: *Natural Gas Engineering, Second Edition*, Mineral Industries Extension Services, School of Mineral Industries, The Pennsylvania State College (1948), page 169
- Petrie, H.L., Wilson, P.M., Smart, E. E.: *Jet Pumping Oil Wells, Part I*, World Oil, Production '83, November, 1983, page 51
- Schraufnagel, D. G., Hill, D.G., McBane, R.A. Gas Research Institute, *SPE 28581, Coalbed Methane - A Decade of Success*, Society of Petroleum Engineers Library, Prepared for 69th Annual Technical Conference & Exhibition, New Orleans, LA, September 25-28, 1994
- McCoy, J. N., Podio, A. L., "Improved Downhole Gas Separators", Southwestern Petroleum Short Course, Lubbock, Texas, April, 7 & 8, 1998.
- Clegg, Joe Dunn: "Another Look at Gas Anchors," proceedings 36th Annual Meeting of the Southwestern Petroleum Short Course, Lubbock, TX (April 1989)
- Stanley Filter Company, 4444 E. 146th St. North, PO Box 130, Skiatook, OK 74070

7. Parker, R. M., "How to Prevent Gas-Locked Sucker Rod Pumps", *World Oil*, June 1992, 47-50
8. Lea, J. F., "New Pump-Off Controls Improve Performance", *Petroleum Engineer International*, December, 1986, pp 41-44.
9. Klein, S. T., "Selecting a Progressive Cavity Pumping System", *Southwestern Petroleum Short Course*, Lubbock, Texas, April 20-21, 1994
10. Trammel, P., & Praisnar, A., "Continuous Removal of Liquids from Gas Wells by use of Gas Lift" *SWPSC*, Lubbock, Texas, 1976, P. 139.
11. Stephenson, G. B., and Rouen, B., "Gas-Well Dewatering: A Coordinated Approach", SPE 58984, presented at the SPE International Petroleum Conference and Exhibition in Villahermosa, Mexico, February 1-3, 2000.
12. Johnson, K. J., Coats, A., and Marinello, S. A., "Gas-Lift Technology Applied to Dewatering of Coalbed Methane Wells in the Black Warrior Basin", *SPE Production Engineering*, November, 1992.
13. Thrash, P. J., "What About Gas Lifting Tubingless Completions", *The Petroleum Engineer*, September, 1960, p. 33-38.
14. Johnson, K. J., Coats, A., and Marinello, S. A., "Gas-Lift Technology Applied to Dewatering of Coalbed Methane Wells in the Black Warrior Basin", *SPE Production Engineering*, November, 1992.
15. Boswell, J. T., & Hacksma, J. D., "Controlling Liquid Load-Up with Continuous Gas Circulation", SPE 37426, presented at the Production Operations Symposium, Oklahoma City, OK, March 9-11, 1997.
16. Adair, R. L., Kramer, T., "New Technologies for Progressive Cavity Pumps", *Southwestern Petroleum Short Course*, Lubbock, Texas, April 25-26, 2001.
17. McCoy, J. N., "Analysis and Optimization of Progressing Cavity Pumping Systems by Total Well Management", paper presented at the 2nd SPE Progressing Cavity Pump Workshop, Tulsa, Oklahoma, November 19, 1996.
18. Griffin Pumps Operators Manual, 5654 55th Street, S. E. , Calgary, Alberta, Canada, T2C 3G9
19. Weatherford ALS Progressive Cavity Pump Manual
20. Saveth, K.J., "Field Study of Efficiencies Between Progressing Cavity, Reciprocating and Electric Submersible Pumps", SPE 25448 presented at the Production Operations Symposium , Oklahoma City, OK, March 21-23, 1993.
21. Centrilift Submersible Pump Handbook, 6th Edition.
22. Schlumberger-REDA bulletin on the Advanced Gas Handler (AGH) stages.
23. Lea, J. F., Turpin, J. L., & Bearden, J. L., "Correlation of Performance Data for Electric Submersible Pumps with Gas-Liquid Flow", presented at the SWPSC, Lubbock, TX, April 23-25, 1986, pp 267-281.
24. Hebert, D. W., "A Systemic Approach to Design of Rod Pumps in Coal Degasification Wells", SPE 19011, presented at the SPE Joint Rocky Mountain Region/Low Permeability Reservoirs Symposium and Exhibition, held in Denver, Colorado, March 6-8, 1989