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Multiphase Pumps Solve Liquid Loading

By Sven Olson

ALLENDALE, N.J.–An increasingly large number of producing gas wells are maturing. Operators must resolve a number of new problems that arise as late-life wells become more common, which will impact the total economics of their production.

The most common development for maturing gas wells is reduced bottom-hole pressure and increased production of liquids, predominantly water.

Hydraulic fracturing and other stimulation techniques are helpful. However, inevitably as a well matures, a number of decisions need to be made. Abandoning a mature well was once an option, but with higher gas prices and regulatory bodies appearing more and more hostile toward abandoning producing wells too early, producers are looking at new technologies such as multiphase boosting as options to maintain economical late-life production. Wet gas and high gas/oil ratios are field conditions familiar to today's multiphase pumping technology.

Principle Of A Multiphase Pump

Multiphase pumping technology is now 10 years into active service among producers all over the world. The principal benefits of the technology are:

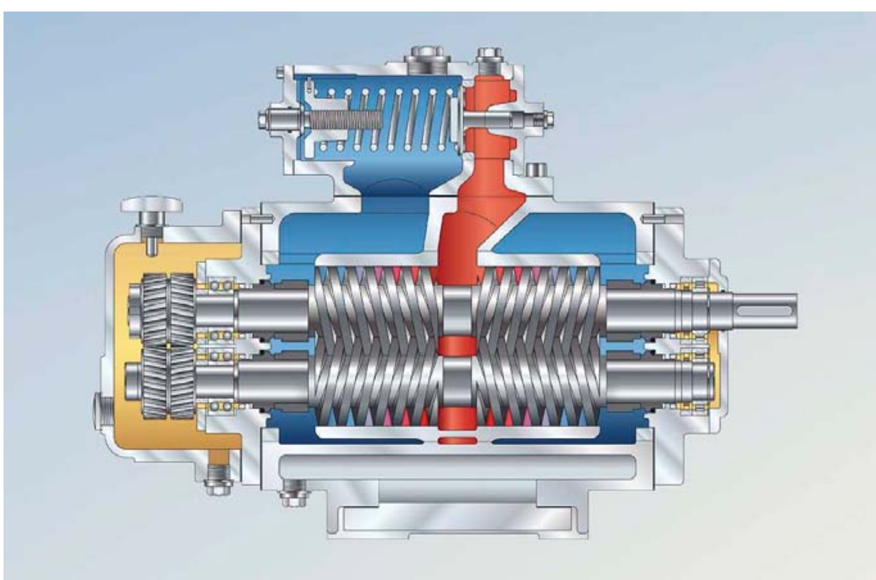
- It reduces back pressure on the well by boosting the untreated well flow, and by allowing the reservoir to accelerate production and the operator to delay abandoning a producing well.
- Facility requirements are reduced by eliminating separation and processing equipment such as separators, flares, pumps, compressors, flowlines, etc. With multiphase pumping, process facilities can be centralized and optimized for gathering a large number of producing wells, thereby reducing footprint and limiting environmental impact, as well as drastically reducing operating and capital expenditures.

Flow assurance is an equally important benefit of multiphase pumping. Increased liquid production, slugging–especially terrain-induced liquid slugging, which is very difficult to address–and surging are problems. Multiphase pumps have the advantage of catching and breaking up slugs and allowing first-stage production separation to work without liquid carry-over or other upset conditions. The same problems occur with risers, where slugs effectively can be mitigated by using multiphase pumps.

Equally important is the ability of a multiphase pump to draw down the flowline pressure below hydrate formation pressure, thereby saving on methyl ethylene glycol, methanol and other inhibitors, as well as permitting trouble-free startup of shut-in flowlines.

FIGURE 1

Twin-Screw Multiphase Pump



Multiphase Pumping

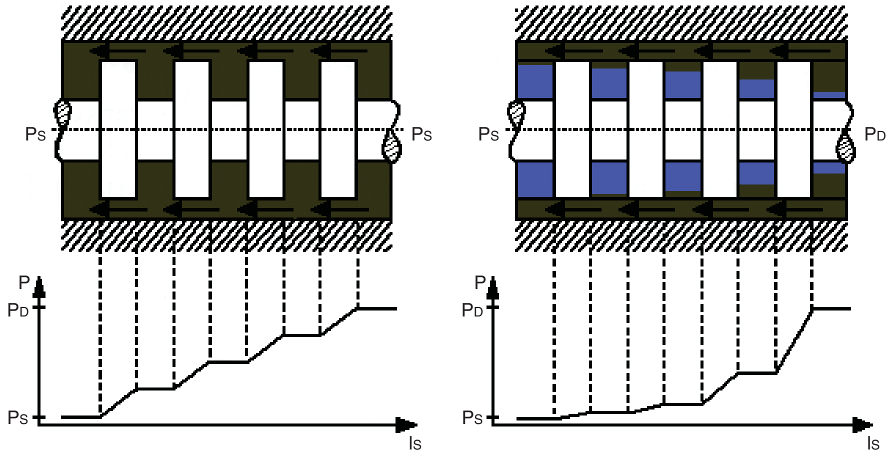
A multiphase pump by definition is a pump that is also able to transport gas. It is an isothermal machine in which the heat generated by compressing gas is carried away by the flow stream through the pump, contrary to a compressor, which is an adiabatic machine and requires additional cooling.

This article focuses on twin-screw, positive-displacement type multiphase pumps. There are other types of multiphase pumps referred to as helico-axial. These are dynamic machines that depend on density and inlet pressure. Twin-screw multiphase pumps, which are the most common, work with fixed displacement, where each pumping chamber formed when the two meshing screws rotate delivers a constant volume from inlet to outlet.

The liquid part of the multiphase flow

FIGURE 2

Pumping Compressible Gas/Liquids



becomes very important in compressing gas. As shown in Figure 1, the twin-screw pump uses two opposing sets of screw profiles to move inlet flow from opposite ends of the screw sets toward the middle, where it connects to the pump outlet. When the screws or rotors turn, the centrifugal forces cause the liquid phase to separate from the gas phase. The liquids concentrate in the perimeter of the screw set in the annulus between the liner and the screw tips, and between the screw tips and the root of the profile.

As the flow moves from the inlet toward the outlet, the liquid phase becomes more defined and a laminar stream of liquid travels in the opposite direction of the main flow stream. The reverse flow of liquids is a result of the pressure buildup from downstream lines or the separator pressure control.

When the back-flow of liquid–which as a result of pressure is practically dead–reaches and fills the next upstream pumping chamber, the liquid will compress the gas in the chamber. Overflow liquid will continue to fill preceding upstream chambers, and the gas compression will occur as the liquid continuously fills the chambers. Somewhere there will be equilibrium between gas and liquid pressures, and the combined liquid/gas flow will reach the discharge port of the pump and continue downstream.

As shown in Figure 2, the pressure buildup is progressive from chamber to chamber. However, compared to liquid (brown), it is in the last chamber before the outlet where most of the gas (blue) compression takes place. Although a typical twin-screw multiphase pump is a constant-displacement machine, the back-flow of liquid makes it a virtual variable-displacement machine, thereby allowing it to compress gas.

It is still a classic pump, which enables it to transport 100 percent liquid at any time, which is not possible in a variable-displacement machine such as a compressor or a pump with variable displacement in order to operate with solid liquid. Figure 2 shows the difference in pressure buildup between solid liquid and multiphase flow.

With that being said, it becomes obvious that the presence of liquid is critical to successful gas compression. The liquid normally needs to be 2-5 percent of the inlet flow for most twin-screw multiphase pumps to flow in a laminar regime, chamber to chamber, as described here.

At higher gas void fraction (GVF) (98-99 percent), the integrity of the liquid phase is no longer stable, and the liquid will foam and/or move in a turbulent flow regime. At this time continuous chamber-to-chamber back-flow is no longer possible, and the pump loses its ability to compress gas and move the compression heat away from the pump. As a result, the pump may vapor lock, causing a very fast-damaging heat buildup and the pump would have to be shut down.

Liquid Management

The previous discussion indicates the importance of liquids when compressing gas. The liquid is, however, both a blessing and a curse. It is critical to keep the required amount of liquid in the pump at all times and not have it flashed or lost. This requires incorporating a system to trap the liquid in the design. This is referred to as liquid management, which has to be complete and sized correctly for the flow regime the pump is expected to experience.

Proper liquid management brings the pump the "compression device," which allows the pump to work over a wide range of GVF. Liquid management also will allow the pump to effectively handle liquid slugs, which are normally the nature of multiphase flow.

GVF is an average number, and in real life a multiphase pump will encounter slug flow with GVF changing from 0 to 100 percent instantaneously, depending on the nature of the slug. Just as it is necessary to provide a safe liquid source, one can turn this into an advantage with a gas well by allowing the pump to compress the gas without worrying about the produced liquids.

Figure 3 shows a standard piping and instrumentation diagram with a liquid trap down stream of the pump. The liquid trap can be anything from a simple liquid knock-out boot to a cyclonic separator, or a high-efficiency two-phase separator with demister pack, liquid level control, etc. Figure 4 shows a standard configuration using a cyclonic separator to trap and retain liquids.

Because liquid management is so vital for multiphase pumping, it is also a

FIGURE 3

Standard Piping and Installation Diagram

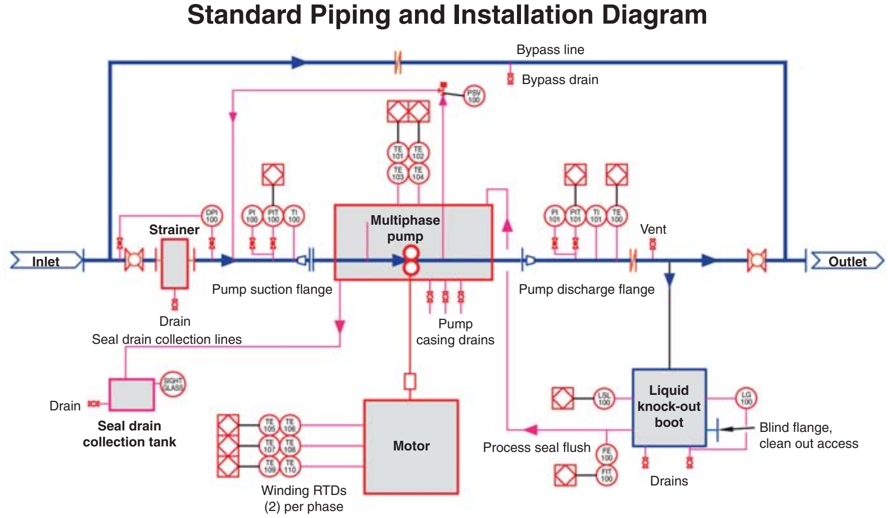


FIGURE 4

In a standard configuration, a multiphase pump uses a cyclonic separator to trap and retain liquids.

blessing that can be taken full advantage of when handling liquid-loaded gas wells. In other words, it is more than a tool to handle produced liquids.

The Liquid Advantage

An aging reservoir will gradually approach a point at which the liquids become a serious constraint. High bottomhole pressure increases the density of the gas, resulting in higher liquid saturation, which will help remove liquids efficiently with the gas stream.

With lower bottom-hole pressure, the gas velocity drops and the liquids are much more difficult to carry, to the point that wells become liquid locked fairly quickly. Under these circumstances the energy to overcome the back pressure at the wellhead is simply not available anymore. Moving the liquids out of the well bore now becomes the major challenge.

There are a number of techniques available, such as electric submersible pumps, rod pumps, jet pumps, gas lift, and combinations thereof. The main disadvantage is the inflexibility of these techniques to adapt to the changing conditions of aging wells. They are sized for narrow operating windows, and when the well moves off this point the equipment has to be taken off line, modified and reinstalled.

Downhole equipment will require extensive workovers, and the economics of the upgrade may become an issue–not to mention overall expenses, gas locks, cavitation problems, etc. Multiphase boosting is a surface technique for which the aim is to off-load the well from the flowline and separator arrival-pressure constraints.

By lowering the wellhead pressure, the velocity in the production tubing will again rise to a level where the gas can start moving the liquids. The lower wellhead pressure will, however, add substantially to the gas volume that the pump handles. The larger volume resulting in larger flow will in turn require larger pumps. The larger pump will be less efficient, requiring a larger driver and added capital costs. At some point, depending on the application, the question becomes whether the multiphase pump is a better solution than a compressor with adequate inlet separation and a blow case.

Working In Combination

The correct answer may be a combination of a compressor and a multiphase pump. The pump, as well as the compressor, can be gas-engine driven. Such combinations are used in the field where the free-water knockout is used to trap the liquids upstream of the compressor. The liquids, with some gas entrained, go through the multiphase pump. The pump also is taking the remaining liquids from the inlet scrubber of the compressor.

The compressor now handles the majority of the gas, reducing the size and the cost of the multiphase pump considerably. The gas and liquid streams can then be recombined for further transportation through a multiphase flowline. This combination eliminates liquid problems for the compressor, and because of the pump's gas handling ability, upsets or gas carry-under is no longer a problem.

Several subsea processing designs have used this concept where, of course, the liquid handling is much more complex and costly.

The advantage of multiphase boosting can be achieved with various types of producing wells. There is a fuzzy line between a liquid-producing gas well where the liquids are condensate and water, and an oil well with high GOR and water cut. Water production is an issue in both cases because gas is not very soluble in water, and gas entrained in condensate and oil is impossible to handle for a normal compressor.

The gas handling for an oil well normally is focused on removing annulus gas from the well bore, which results in increased liquids production. A very special case is cyclical steam production where vapors and gases need to be removed from the annulus at high temperatures to allow the liquid production, mostly bitumen, to continue during a prolonged pumping cycle.

This production scenario is prevalent in Canada where multiphase pumps have, for many years, successfully performed a job previously done by liquid ring pumps, vacuum pumps, separators, flares, etc. A dominant part of the total number of installed twin-screw multiphase pumps in Canada is used in cyclical steam production.

Collect Annulus Gas

Annulus gas gathering is also very important in conventional oil production. The conventional way of venting or flaring the gas is no longer an option in most parts of the world. Separate gas gathering systems are expensive, complicated, and often unreliable because of liquid upsets. They require separate gas lines, liquid separation controls, and compressors.

An alternative is to use a multiphase pump to collect annulus gas. This can be done economically on a single well basis where the annulus gas flows through the multiphase pump, and the liquids produced by an ESP or rod pump are recombined with the gas downstream of the multiphase pump.

A bleed of some liquids to the multiphase pump will assure proper liquid management for the pump in case the liquids in the annulus gas stream are insufficient.

The successful selection of a multiphase pump for conventional gas wells depends on flowing conditions, gas volume, liquid flow, whether flow is water and/or hydrocarbons, temperature, presence of hydrogen sulfide and carbon dioxide, slugging and slug regime (if known), inlet pressure, and required pressure boost.

Solids are another variable that needs

to be addressed. Sand from hydraulic fracturing has shown a bad habit of traveling with the gas stream and causing significant wear on rotating equipment. It may be necessary to include a desander in the system if trap sands are a problem. The liquids handling normally is less of an issue.

Liquids from an upstream free-water knockout can be used to supply the pump with a steady stream, using a small pump to inject the liquid into the inlet of the multiphase pump. Figure 5 shows an installation for Devon Canada, where an upstream free-water knockout catches produced liquids that are then supplied to the multiphase pump through small liquid pumps. This allows the multiphase pumps to run on 100 percent gas for extended periods. If the site has utilities such as water available, that is also an alternative.

Another way to approach liquid collection is to install a full two-phase separator downstream of the pump using the differential pressure to inject the liquid into the multiphase pump. This separator could have a demister pack for high separation efficiency, and liquid level control to dump excess liquids downstream.

All these solutions are successfully applied today in gas wells and annulus gas gathering.

So in summary, liquid loading is a problem in 80 percent of all producing gas wells in North America. The need to extend reservoir life and produce additional hydrocarbons is becoming a necessity both for the operator and the leaseholder. Regulatory agencies are becoming aware of emerging late-life production technologies that make this possible, and can be expected to pay increased attention to these issues.

Multiphase pumping is one of the emerging technologies that can offer an operator the correct tool. It is a straightforward technology based on a gas-tolerant pump design, which with its surface location, simplicity in operation, and reasonable capital cost is attracting increased interest. As with all machinery, multiphase pumps need to be appropriately applied, with proper installation and sizing to suit the actual flow regime.

Already successfully installed in many places, multiphase pumping has much more to give and is expected to be a major tool for producing late-life natural gas wells. ❒

FIGURE 5

Devon Canada's multiphase pump installation employs a free-water knockout to catch produced liquids, which enables the pump to run on 100 percent gas for extended periods.

SVEN OLSON

Sven Olson is president of Leistritz Corporation, based in Allendale, N.J. With headquarters in Germany, Leistritz manufactures screw pumps for the oil and gas industry. Before joining Leistritz in 1986, Olson spent most of his career with IMO in Sweden. He was involved in testing and introducing multiphase pumping technology to North America, and actively participates in applying and promoting the technology in the oil and gas industry. Olson serves as an advisory board member of the Multiphase Pump Users Round Table sponsored by Texas A&M University. He holds a degree in process engineering and an M.B.A. from the University of Lund in Sweden.