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New Technology

Multiphase Pumps Offer Simpler, More Economic Method For Producing Oil And Gas

Multiphase Pumps Provide New Option

By Sven Olson

ALLENDALE, N.J.–Conventional methods for producing oil and gas can now be replaced by a simpler, more economic method using multiphase pumping technology. Multiphase pumping does not require separation of oil, gas or water, so the entire production stream from the wells can be gathered and boosted to a central processing facility without requiring separate flow lines, separators, heater treaters, intermediate storage tanks, gas flares, compressors or separate pumping facilities. Eliminating this equipment means substantially reduced facilities and a much more economical installation for pressure boosting production so it can move farther downstream for processing, which makes it ideal for marginal field developments.

Multiphase pumps also can handle very low inlet pressures, which makes them suitable for lowering the wellhead backpressure. In most wells, particularly those on artificial lift, substantial gains in production can be achieved with even a modest drop in the surface flowline pressure–enough to pay off the installation cost within only a few months, in many cases.

Multiphase pumping technology is relatively new, however, and has only recently gained acceptance as an oil field production tool. The first step to field test multiphase pumps started less than 10 years ago. Two dominant pump technologies are being utilized: the helicoaxial principle, and the twin screw principle. Both pump types today have been installed onshore, topside and in subsea applications with good results. Other pump types, such as piston pumps and progressing cavity pumps, also have been applied for multiphase service, although in limited numbers.

The manufacturers of all these different pump designs have spent a lot of effort and money to perfect the designs, and have now reached, in most cases, a level of reliability equal to or better than similar pumps and compressors.

Driving Forces

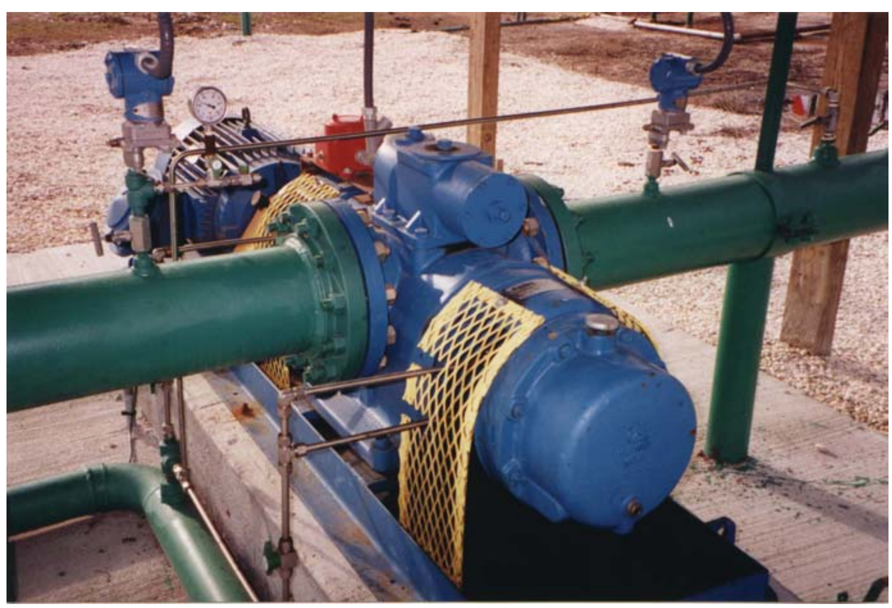
The forces that are driving progress in multiphase pumping usage are sometimes hard to identify. The traditional sales pitch, which most manufacturers advocate–namely the increased or accelerated production scenario by reducing wellhead pressure–may not appeal to all operators. It seems operators are much more conservative when looking at expected revenue increases from higher oil production compared to the economic benefits of lowering operational costs. Therefore, it is not always easy to establish the net present value of an installation. There have been actual cases where predicted production increases have been matched by offsetting risk factors and doubling safety margins simply because of the young age of multiphase pumping technology.

For the operator, the economical justification for using multiphase pumps is, of course, a top priority. However, it is more credible to the argument to show savings in both capital and operational costs, rather than focusing on estimated revenue increases from higher oil production. So where do we go to find the cost savings, and in what type of installations could they have the highest impact?

With the industrywide predictions of lower-quality crude oils produced and coming to the market in the future, multiphase pumps are expected to be an important tool to handle well fluids such as emulsions, waxy crudes, bitumen and the extra heavy crude laden with sand. In wells subject to declining reservoir pressure and increased water and gas production, multiphase pumps are guaranteed to bring production to the processing facility independent of wellhead pressure.

Multiphase pumps, with their ability to flow any untreated well stream without slugging or surging, above all, are flow assurance tools. As an example, hydrate control in Canada is being done using multiphase pumps where the entire production would otherwise have to be shut in during the cold season. Also in Canada, multiphase pumps are being used to draw vent gas and steam from well casing in cyclical steam production, while enhancing total recovery by lowering the casing gas pressure.

In all of these cases, the economics are focused on the flow assurance aspect of multiphase pumps. The benefits of these installations apply to all types of oil production, whether in major-sized fields or marginal remote fields.



A multiphase pump was installed in the Humble Field north of Houston in 1998 to produce to a facility three miles to the south. The field was already more than 60 years old, and was barely flowing from beam-pumped wells. Today, the field is still in operation, with the multiphase pump continuing to extend the life of the mature property by boosting the pressure to reach the process facility while lowering the production manifold pressure.

Facilities Reduction

The most powerful driving factor for using multiphase pumps, however, is the reduction of production facilities. During the producing life of a typical reservoir, various amounts of processing facilities are required. Initially, natural reservoir pressure drives production flow from the wells, with gas lift or artificial lift equipment added later in field life as reservoir pressure declines. The location of facilities in relation to the producing field is set so that production can arrive at the processing facility at an acceptable pressure and flow.

As the field continues to age, added reservoir pressure support is usually required, mostly through water flooding. The result is a change in water cut and gas-to-oil ratios, both of which add requirements to the facilities. The operator, of course, desires to delay field abandonment as long as possible to maximize total recovery. In conventional production, all of this means either high upfront costs to cope with the ever-changing production scenario over the history of the field, or alternatively, stepwise gradual equipment additions needed to flow the wells, such as free water knock-outs, low-pressure separators, heat treaters, etc. In a marginal field, these costs may be prohibitive at the outset, so the field may never get produced. Or, because of the cost of increasing facilities needs during the field's productive life, wells may be prematurely plugged and abandoned.

This is where multiphase production comes in. Thanks to its large operating window, which comes from design and operational flexibility of the pump itself, the operator now has the means to economically produce smaller fields or even fields that have been abandoned because conventional production facilities requirements have rendered them uneconomical to operate.

The key term is "facilities reduction." The cost impact of being able to produce a marginal field back to an existing or centralized process facility instead of processing in the field is enormous, resulting in substantial savings not only in capital costs, but also maintenance, energy, and perhaps most importantly, manpower. The producer who can eliminate satellite facilities–including flow lines, separators, pumps, compressors, and free water knock-outs in the field–and bring the multiphase flow though a single flow line into a centralized processing facility stands to gain the most. This is especially true for remote fields.

In the 25-year-old San Francisco Field in Colombia, multiphase pumps were installed in remote parts of the field, where wells at lower elevations could no longer flow back to the processing facility, located at the highest point of elevation. Not only did the low-flowing wells come back onto production after installing the multiphase pumps, but the lower pressure on the wellheads also resulted in a significant increase in oil and gas production.

The twin screw multiphase pump has a high degree of operational flexibility thanks to its design principles and the possibility to vary speed, thereby flowing between 30 and 110 percent of rated capacity using an electric motor with variable-speed drive.

Typical low-pressure pumps operate with up to 450 psi pressure boost, and high-pressure pumps go all the way up to 1,200 psi boost. In multiphase pumping, the gas and liquid phases have to be brought together under a common denomination. This is simply done by converting the gas flow from standard cubic feet (scf/d) to actual cubic feet at pump inlet pressure and temperature conditions (acf/d) using the gas formulas. The gas volume is recalculated into barrels per day and the liquids are added to the gas. The result is an inlet flow expressed in barrels per day equivalent. Multiphase pumps can flow all the way up to 300,000 bbl/d equivalent, depending on pressure boost.

Pump Sizing, Selection

An important factor in sizing the pump is the gas flow at inlet conditions. The principle of multiphase pumps requires a small amount of liquid to be present within the pumping elements. On average, the gas volume fraction (GVF) is limited to 95-98 percent at inlet conditions. The liquid is necessary for sealing and compression of the gas phase, and has to be maintained also during slugging or surging conditions. Pump manufacturers use different methods to gather liquids, either from inlet flow conditioning or through liquid recirculation. With internal recirculation, a pump can handle short gas slugs, and with external recirculation, larger gas slugs up to 30 minutes or more.

The gas handling aspects of multiphase pumping is more critical in a remote or marginal field development. With a gas-to-liquids ratio over 1,000 and no makeup liquids easily available, the point could be quickly reached where multiphase pumps would not be the best solution because of pumping efficiency and growth in pump size. A bad combination of low pressure and high GLR can be an obstacle for taking advantage of all other multiphase pumping benefits, and the cheapest way to produce may be a compressor with a blow case. The optimum equipment solution can be designed by analyzing marginal field production flow.

It is important when selecting the equipment for marginal field production to look at not merely the pump itself, but the entire package. A first step, of course, is to size the pump for coping with low and high flows, depending on the number of wells producing or shut in, allowing for margins for unexpected future upset conditions. With variable-speed control, a pump can typically be selected to pump the rated flow at 75 percent of synchronous pump speed. The packaging should include a variable frequency drive/programmable logic controller (VFD/PLC) combination that allows the pump to run at a speed that corresponds to a desired inlet pressure independent of the number of producing wells. The VFD/PLC combination also protects the pump, driver and auxiliary equipment, and provides input to a supervisory control and data acquisition system.

A typical unmanned multiphase pump package also includes a suction strainer, block valves, PSV and a bypass line to allow product flow in case of a pump shutdown. The liquid recirculation system is also very important. As mentioned, the external system, which relies on liquid trapped in a boot just downstream of the pumps discharge, will allow the pump to function during very long gas slugs of up to one hour and will not trip due to a lack of liquid and overheating. In a remote, unmanned field, frequent automatic shutdowns are not wanted because pump restarting is a manned operation that requires dispatching personnel to the site. Successful remote marginal field operations rely on a complete and rugged multiphase pump package with built-in redundancy to cope with all the unknowns that tend to show up when least expected.

Field Applications

There have been a number of field applications where multiphase pumps were installed with the sole purpose of boosting production flow from remote locations. A case in point from a marginal property is the Humble Field north of FM 1960 outside Houston. In 1998, Texaco decided to install a multiphase pump in the field to produce back to a facility three miles south. The field was already more than 60 years old, and was basically depleted and barely flowing from beam-pumped wells, most of which were on timers. The multiphase pump was able to efficiently boost the pressure to reach the process facility, and also lowered the production manifold pressure all the way down to 5 psi. The installation is small, but it is still in production, continuing to extend the life of this old field for the benefit of the operator.

On the other end of the scale, in Chad, Africa, ExxonMobil (Esso Exploration and Production Chad Inc.) relies on centralized processing, bringing production from four different fields into a central processing facility using multiphase pumps. This production system efficiently uses single-flow lines, minimizing impact on production sites and the environment. A total of 14 multiphase/emulsion pumps are installed in the four fields. The pumps, which are driven by electric motors from 500 to 1,600 horsepower, have complete packages with seal/lube oil systems and discharge manifolds to recirculate small amounts of liquid to the pump. The concept of centralized operation and processing for remote fields is demonstrated in a large scale, which very well can set a standard for future developments.

The San Francisco Field in Colombia is another remote field. It has been producing for more than 25 years. The terrain is mountainous, and when the field initially was planned, the processing facility was placed on the highest elevation to accommodate the export flow line, whereas the producing wells with satellites and well testing were located in the valleys at the lowest elevation points.

With good reservoir pressure, later assisted by electric submersible pumps, there were no problems producing back to the battery facility on the hilltop. However, when the water cut started creeping up with increased use of water reinjection, the more remote wells could not flow back and some had to be shut in. It was decided to install multiphase pumps in lieu of upgrading the satellites with two-phase separation, compressors and new flow lines. Three multiphase pumps were installed in remote parts of the field, and not only did the low-flowing wells come back to production, but the lower pressure on the wellheads resulted in a significant increase in the oil and gas production.

Again, as needed in this environment, multiphase pumps are packaged and installed for unmanned remote operation with only weekly inspections by the operator according to the current schedule. The reduction in manpower was also very favorable compared to conventional production. Well testing has also been centralized using a selector valve at each multiphase pump site.

These are only a few examples of successful operations of marginal fields using multiphase pumps. Even with all the technology's success, however, multiphase pumps are still not being applied as frequently as they could be, often because of a lack of knowledge about the benefits the technology can really bring to the operator. In North America, declining and marginal fields are becoming much more important for future oil production. It is necessary that operators and asset managers start looking to introduce new technologies. Multiphase boosting is such a technology that has already been through its "shakedown cruise" and now is ready to be applied.❒

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Sven Olson is president of Leistritz Corp., 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 the first testing and introduction of multiphase pumping technology in North America, and is actively participating in applying and promoting multiphase pump technology in the oil and gas industry. Olson serves as an advisory board member to the Multiphase Pump Users Roundtable, sponsored by Texas A&M University and held annually in Houston. He holds a degree in process engineering and an M.B.A. from the University of Lund in Sweden.