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Multiphase Enables 'Minimal Approach'

By Stuart L. Scott

HOUSTON–Pad-based horizontal drilling techniques have revolutionized development of onshore unconventional reservoirs. In shale fields that often require drilling and completing hundreds of wells within relatively small geographical areas, the ability to "batch" drill and stimulate multiple laterals on a single pad dramatically improves operational efficiencies and overall cost structures for both constructing horizontal wellbores and completing them with multistage hydraulic fracturing treatments.

However, the focus on improving efficiency should not stop when wells are completed and turned to production. By deploying game-changing advances in surface production technology, operators can adopt a "minimal" approach based on a multiphase production facility (MPF) to move almost all production equipment from the individual pad site to a concentrated, centralized location, which provides a number of cost savings and operational advantages–particularly given the size and scale of resource plays.

Prior to the oil price collapse in late 2014, the application of MPFs for pad-based unconventional field development was limited by the intense focus on drilling and fracturing wells, and on acquiring and holding leases. High initial production rates hid the impact of long-term production issues and production facility optimization.

With lower prices and curtailed drilling activity, operators are looking to understand how costs can be reduced and how pad compression can be utilized to better maintain production from low-permeability reservoirs with steep decline rates in their first few years of production.

Simply put, utilizing an MPF, with pad-level multiphase pumping and metering, provides a step-level change that can differentiate a company as a top-tier performer in several key areas. The strategy a company employs for its surface production facilities has an enormous impact on long-term operating expenses, recovery rates, and relationships with stakeholders in the local community. Given advances in technology, the industry can do things differently now in ways that have a significant impact on full-field development costs and realize long-term asset value.

Multiphase production has been used elsewhere in the oil and gas industry to eliminate flaring/trucking and to reduce development costs, and has the potential to provide several other critical advantages–ranging from well testing to gas well deliquification–for pad-based onshore developments.

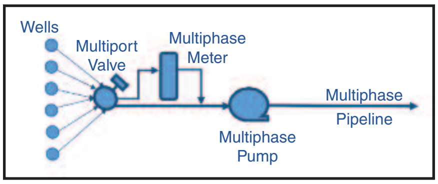
The Case For MPF

Figure 1 illustrates an example equipment layout at an individual well pad using the MPF approach. The "minimum facilities," multiphase production concept offers several strategic advantages over traditional production facilities, including:

- A dramatically smaller operational footprint;

FIGURE 1

Pad Site Multiphase Production Facility Layout



- Lower capital and operating expenses;
- Reduced health, safety and environmental risks;
- Enhanced artificial lift performance; and
- Improved well and reservoir management and surveillance.

The small-footprint MPF approach requires only a multiphase meter and pump at the pad, rather than the stock tanks, water tanks, production and test separators, and associated manifolds typical of a traditional production facility. That not only reduces the total amount of equipment required, but also allows much of the equipment that is now installed on individual pads to be concentrated on a centralized facility serving multiple pads to substantially reduce the space occupied on each pad site and lessen the visual impairment/community impact.

The MPF approach also enables operators to proactively reduce HS&E risks by eliminating pad separators and tanks on pads, reducing hydrocarbon storage on each pad and the associated risks of spillage. Also moved from well pads are vapor recovery systems, tank vents, flare systems, and the permits/inspections associated with these production vessels. Trucking to each pad, with its enormous community impact and risk, is eliminated also, since all produced fluids are pumped to a central facility for processing.

Applications using the MPF approach have reported a 30 percent or greater reduction in capital expenditures. The cost savings come from eliminating the amount of equipment that must be designed and installed on each individual pad site. For example, one multiphase export pipeline can be installed instead of a traditional facility's two single-phase pipelines leaving each pad.

Note that when tank venting is not allowed and a vapor recovery system or flaring is required, the savings are often orders of magnitude compared with a conventional production system. For example, Aera Energy in California was able to decommission an entire gathering center and pump production to another facility using multiphase pumps.

Moreover, an MPF means installing less equipment, so there is less equipment to operate and maintain. When operating dozens of pads, automating well testing and operations provides a greatly simplified production system with a substantial impact on operating costs that impact the life of the field. In addition to the benefits for surface facilities, multiphase pumps and meters enable other improvements in operations that have significant impact on the value extracted from a given asset.

Improved Recovery

The multiphase pump is integral to an MPF. This provides pad/wellhead compression, which is considered the "first form of artificial lift." Reducing wellhead pressure translates directly into improved recovery. Also, for wells experiencing liquid loading, lowering the wellhead pressure using a multiphase pump often can restore production by increasing wellbore gas velocities to allow liquids production from the well and extend its life.

In regard to reservoir management, an MPF provides improved well/reservoir management and surveillance through frequent automated testing. The multiphase meters utilized as a core element of the MPF require far less time for each test. Conventional well tests using a test separator require time for the separator to stabilize once a well is placed on test. This is eliminated, or at least reduced, for multiphase meters.

As has been demonstrated in multiphase meter field applications, more frequent well tests with better accuracy improve reservoir analysis and forecasting.

Finally, the MPF approach gives operators the ability to take a "full life cycle" view of operating expenditures. While initial production from hydraulically fractured shale wells is strong, more than half of the reserves are recovered over an extended period, which may be 20 years or longer.

Field developments utilizing a MPF provide value for the long-term operation of the field through lower operating costs. The automated nature of an MPF reduces visits from field staff, and there is far less equipment to maintain, inspect and permit.

That said, it should be noted that the higher-level pumping and metering technologies used in an MPF often require field staff to be trained to a higher level.

Multiphase Pumping

Multiphase pumping has become the standard production method in several key oil and gas producing arenas. For heavy oil, multiphase pumping is used for pad-based development in Canada, California and Venezuela. Off shore, seafloor multiphase pumping is used widely and has established a strong track record of reliability.

There are several types of multiphase pumps, but they fall into two main categories: rotodynamic and positive displacement pumps.

While rotodynamic systems such as electric submersible pumps and seafloor helico-axial pumps dominate subsea applications, positive displacement pumps dominate on shore. The key for utilizing them in MPFs is the gas-handling ability of the pump.

The majority of wells drilled in U.S. shale plays produce multiphase streams. In fact, pad horizontal wells in tight oil plays typically exhibit gas volume fractions (GVFs) of 80 percent or higher at the wellhead. Positive displacement pumps such as twin-screw pumps (TSPs) and progressing cavity pumps (PCPs) better lend themselves to high-gas-fraction production.

The results of research projects examining the performance of both PCPs and TSPs under high-GVF conditions indicate that both technologies are able to boost pressures, even when GVFs are greater than 90 percent.

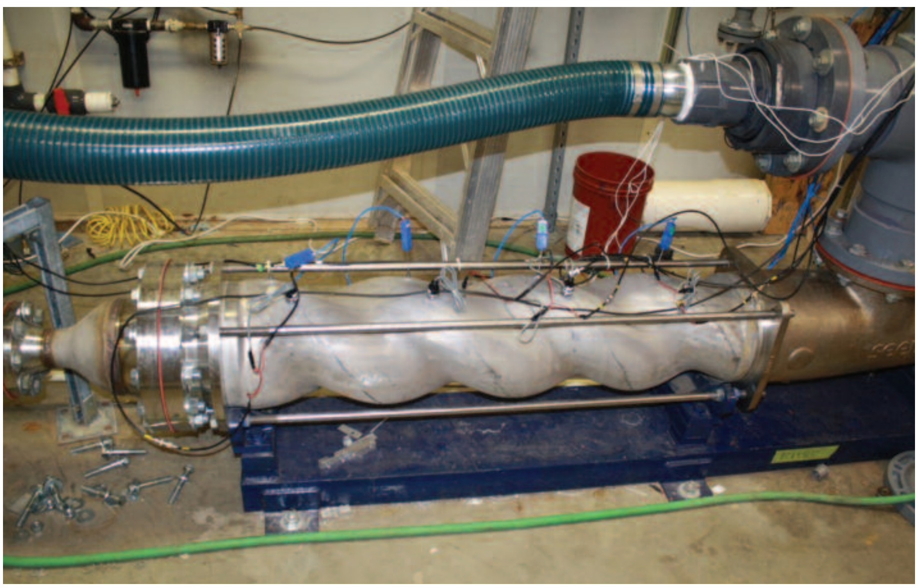
Figure 2 shows a SEEPEX PCP on the test stand during research conducted at Texas A&M University. The PCP has equal-wall-thickness stator technology, which with a close fit between the metal rotor and rubber stator, was able to reach high volumetric efficiency. While the system achieved volumetric efficiencies above 95 percent for all test conditions at full speed, it is believed that adding a liquid recirculation system would allow the pump to achieve higher efficiencies even when the process fluid entering the pump is at 100 percent GVF.

Virtually no field installation of a PCP recirculates fluid from the pump discharge to the pump suction. Trapping and cooling a small amount of liquid at the pump discharge and routing it to the pump inlet should improve the run life of the stator and allow better dissipation of compression heat generated when GVFs are continually in the 90-100 percent range.

Another Texas A&M research project tested high-GVF operation using a Leistritz TSP, and successfully demonstrated the ability of a surface twin-screw pump to

FIGURE 2

Progressing Cavity Multiphase Pump Testing at Texas A&M University



provide wet gas compression. With this design, compression is generated by the backflow of liquid from the pump discharge to the pump suction though chambers created by the intermeshing of the two screws.

As shown in Figure 3, a small vessel is utilized to trap a small amount of liquid and re-circulate it to the pump discharge. This allows the pump to run without liquid flow for some time, if needed. Cooling the recirculation stream with an in-line passive air cooler (not shown) improves efficiencies for periods when the GVF exceeds 90 percent.

FIGURE 3

Twin-Screw Multiphase Pump Testing at Texas A&M University

Keys To Success

Multiphase pumps utilized for a pad-based MPF need to tolerate some amount of solids from the flow back of proppant used in the fracturing treatments. PCPs handle solids well, and are even utilized as slurry pumps in other applications, but the life of the replaceable rubber stator is reduced. For TSPs, higher-strength materials have been shown to extend the life of the metal screws.

The keys to the success of a multiphase pump as part of an MPF are correct sizing, and cost-effective packaging and auxiliaries. Most multiphase pumps for wet-gas service have been oversized. Properly selecting the motor is a key to unlocking the benefits of the MPF and reducing costs. Typically, pad applications have high production rates early in well life and require little boosting. In later life, the boost requirement increases, but rates are lower.

It is important that the maximum expected rate and the maximum expected boost not be paired when calculating power. This can result in a motor that is one or even two frame sizes larger than required.

Speed control is another area that has driven up costs. The variable frequency drive housing needs to be fit-for-purpose and appropriate. For instance, in arid and relatively mild temperature conditions such as in California, housing can be simple coverings rather than air-conditioned buildings. A hydraulic torque converter is an alternative method for speed control that can be of benefit for applications where power exceeds 250 horsepower. Torque converters have been used successfully with TSPs in both laboratory settings and in the field.

The multiphase meter is another key component at the heart of the MPF approach. Multiphase metering has become a best practice for deepwater developments, but these three-phase meters often are considered too expensive for use on shore. Methods utilizing compact separation are most affordable, and are very effective under the high-GVF conditions normally seen in shale pad production.

The compact separator-based metering approach uses conventional gas, liquid and water-cut meters to reduce cost, and a compact gas-liquid cylindrical cyclone separator concentrates the liquid so that it can be measured more accurately.

Automated well testing is made possible by a multiport selector valve (Figure 4). This valve enables a compact testing manifold, which greatly reduces piping/valves. It uses a single actuator to route one well at a time to the multiphase meter for testing.

Flow Assurance

The improvements in efficiency and reductions of cost derived from an MPF depend on solving the unique flow as-

FIGURE 4

Multiport Selector Valve for Well Testing

surance issues associated with multiphase flow in surface flowlines. There has been great progress in four, broad, flow assurance categories:

- Flowline leak detection;
- Flowline blockage detection and prevention;
- Flow pattern management; and
- Corrosion/erosion.

A pad-based development will have a gas flowline connecting the pad to a gas gathering system or central processing facility. Therefore, some leak detection method is required, typically a mass-balance method or a safety pilot. Multiphase flow complicates leak detection since mass-balance methods are not responsive.

Several methods are possible for multiphase flow. Internal flow-based methods use pressure/temperature sensors and flow meters to quickly detect leaks with minimal additional costs. External, diffusion-based methods allow very small leaks to be detected that are not detectable with traditional methods. Periodic pigging also can be used to inspect flowlines to mitigate risks. The bottom line is that leak detection is possible to enable using an MPF.

Hydrates, wax, scale and other blockages can occur while transporting a full-well stream flow of unprocessed fluids in a multiphase flowline. Fortunately, blockage detection methods are available to monitor flowlines and detect blockages before they become a critical issue. Blockage prevention usually is addressed by using chemical inhibitors and periodic pigging.

In regard to managing flow patterns, slugging is the most troublesome flow pattern, and large slugs can fill separators at the central processing facility. Multiphase pumping generally results in smaller flowlines than systems designed for natural flow, which must be sized to minimize frictional pressure losses from the pad to the central facility.

Slug diameter has been shown to be directly proportional to pipe diameter, so smaller-diameter flowlines reduce the lengths of slugs and the troubles they generate. In addition, any slugging from wells will be mitigated by the PD pump, which will supply a constant volume into the flowline regardless of GVF.

Material selection and inhibition can mitigate most risks associated with corrosion/erosion. Sour service parameters, such as hydrogen sulfide and carbon dioxide content are needed as the MPF equipment is specified and the flowline is designed.

Northern Alabama Project

In early 2015, a project was begun for Crosbys Creek Oil & Gas LLC, an independent producer in northern Alabama's Choctow County. The goal of the work was to restore flow for mature wells that were struggling to overcome a line pressure of 700 psig. A Leistritz L300™ twin-screw multiphase pump was designed to reduce back pressure on the wells to 200 psig. Liquid rates of 300-1,000 barrels a day and gas rates from 500,000 to 1 million cubic feet a day were typical for this field. At the new, lower pressure, this translates to 6,000-14,000 bbl/d equivalent rate (gas and liquid) and a 95 percent GVF.

A complete skip with recirculation piping and liquid knock-out boot downstream of the pump was delivered with a 400-horsepower, 1,800-rpm motor and VFD. The system was designed for remote, unmanned operation with a completely self-supported power supply. Figure 5 shows the boosting system during installation. Installation and commissioning took place during second quarter 2016.

It is now possible to use multiphase pumping and metering as a cost-effective alternative to the traditional production facility designs the oil and gas industry has installed for decades. An MPF has the ability to reduce costs and HS&E risks/impacts, while also improving recovery (through pad compression) and well/reservoir/facility management (through frequent automated well testing). These advances are so significant that they have the potential to differentiate an operator in the areas of production excellence and lowest life-cycle cost. ❒

FIGURE 5

Northern Alabama Mature Field Multiphase Pump Application

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Stuart L. Scott is director of technology at Petroleum Emerging Technology Corporation (PetroleumETC). From 2008 to 2016, he managed Shell's deepwater artificial lift technology program and served for several years as Shell's global artificial lift/pumping principal technical expert. Before joining Shell, Scott held the Bethancourt Professorship of Petroleum Engineering at Texas A&M University, was a faculty member at Louisiana State University, and worked for Phillips Petroleum Company in a variety of roles. He is a distinguished member of the Society of Petroleum Engineers and received the American Society of Mechanical Engineers Henry R. Worthington Medal for "eminent achievement in the evolving field of multiphase pumping." Scott holds a B.S. in petroleum engineering, an M.S. in computer science, and a Ph.D. in petroleum engineering from the University of Tulsa.