May/June 2014

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Gas-Handling Devices Boost Mississippi Lime Production

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ESPs with added technology can successfully provide artificial lift in this play, despite its water challenges.

Artificial lift is giving the Mississippi Lime play a new lease on life, allowing production companies to tap a wealth of resources that would otherwise be inaccessible because of the formation's high water content. Spanning more than 17 million acres across northern Oklahoma and southwestern Kansas, the oil-rich Mississippi Lime has been producing for more than 50 years from vertical wells. Today, operators are applying horizontal drilling and hydraulic fracturing to recover the remaining hydrocarbons, estimated to range from 5.4 to 5.9 billion barrels of oil equivalent. Of the play's more than 32,000 wells, about 2,500 are horizontal, and the number is growing.

Although not a shale play, the unconventional carbonate formation is similar to shales. It is highly fractured and has a complex and varied geology of layered chats, cherts, dolomites and limestones that change vertically and horizontally. Reservoir evaluation methods using petrophysical and seismic data to characterize faults, fractures, porosity and thickness have proved useful for maximizing production—which is a multiphase flow consisting of oil, gas and water—and placing closely-spaced wells.

Unlike other prolific unconventional plays, such as the Bakken and the Eagle Ford, the Mississippi Lime does not demand a high degree of advanced drilling and completion technologies. Wells are shallow—ranging from 3,000 to 7,000 feet deep—and laterals are relatively short, typically around 5,000 feet, making them cost-effective from a drilling perspective. Thickness of the play ranges from 300 feet to 500 feet as it moves to the east, with the pay zone ranging from 100 to 300 feet in thickness. Initial production rates can be as high as 5,000 barrels per day in the core operating area of north Oklahoma. Recovery potential declines as the play moves into Kansas.

Flow rates are generally higher, and production declines slower, than those in other unconventional North American plays. Wells also tend to be cooler, 130 to 160 F, compared to an average 260 F in other formations because of the shallow geology. Drilling and completion costs average $3 million to $3.5 million per well, compared to $6 million to $8 million in other formations.

On the Cover: Engineers install an ESP motor as part of a downhole system.

Lifting Water, Gas & Sand

Mississippi Lime wells produce as much as 98 percent water in some cases, a phenomenon that impacts overall project economics. The higher water cut results in higher lifting costs per barrel and drives the operation companies' objective to maximize production from day one. To achieve maximum production, operators rely on artificial lift methods—such as sucker rod pumps, electric submersible pumps (ESPs) and gas lift.

The steep production decline—often further aggravated by high sand concentration and high gas content with the produced fluids—poses serious challenges to the operation of wells in unconventional plays. Unfortunately, this is not always evident during the first stages of development and can lead to discouraging run times when using conventional artificial lift systems. However, operators and service companies are quickly learning that a successful production development phase in unconventional formations requires fit-for-purpose artificial lift design, equipment configuration, measurements, real-time control and operating procedures. This approach often implies a transitional artificial lift method, such as an ESP, initially, followed by a lower-rate artificial lift system, such as a gas lift or sucker rod pump, for the late stage of the well life cycle.

Within the continuous improvement process, operators in unconventional plays work with service companies and understand that these operational challenges must be considered in the well design and construction phase so that the wells can support the operator's production goals. For example, typically an ESP or a sucker rod pump is set in the vertical section of the well, right above the kick-off point (KOP), because of restrictions—such as a smaller diameter above the KOP, high dogleg severity (DLS) or absence of a tangent or low DLS section to set the ESP. The production of the proppant or sand used in hydraulic fracturing can sometimes determine the artificial lift method that will be used because, even if the well has a tangent section in which the ESP can operate, the risk of having the system stuck in the well is too high.

The gas volume fraction (GVF) at intake conditions is high in this play, especially at low pump intake pressure. Gas can negatively impact ESP performance and run life by causing rapid changes in density that compromise the hydraulic lift capacity of the pump, sometimes causing gas-lock. The nature of the long, horizontal sections of unconventional wells can also lead to gas slugs, which increase the GVF even more.

Standard ESPs rely on centrifugal force to transfer energy to the liquid and gas mixture. However, the liquid and gas can separate, even with a free gas content of just 10 to 20 percent in the pump, resulting in a less efficient transfer of energy. If enough gas accumulates, the pump will gas-lock and prevent fluid movement.

ESP systems equipped with an advanced gas-handler (AGH) device can mitigate these limitations and improve overall lift efficiency by reducing the degradation effects of centrifugal pumps and maintaining the higher gas-to-liquid ratio in the tubing string. The AGH can tolerate multiphase mixtures up to 45 percent free gas and is

The multiphase helico-axial pump system can operate at lower intake pressures with GVF in the pump up to 75 percent, delivering incremental production and improved reserve recovery.

installed as a component of the ESP string, right below the pump.

The AGH reduces vapor bubble sizes and changes the gas-bubble distribution, homogenizing the gas-liquid mixture so that it acts like a single-phase fluid before entering the pump. By processing and conditioning the multiphase gas and liquid mixture before delivering it to the pump, the device allows further drawdown, improves pump uptime and accelerates production.

A more robust multiphase gas-handling device is required with higher GVF. A specially designed, multiphase helico-axial pump safely handles mixtures of up to 75 percent free gas, enabling the ESP to operate at a lower intake pressure without gas-locking. Depending on the application, the system can be installed in conjunction with a standard intake or with a gas separator.

ESP technology has been effective in addressing these challenges when configured with the proper technology and adequate operational practices. A Mississippi Lime operator recently pulled an ESP after 16 months of operation. The operator successfully managed a steep production decline from 5,000 barrels per day (bpd) to 500 bpd with the same ESP system before the workover rig returned to the well.

Extended Pump Life

As the most common technique of artificial lift in North America, sucker rod pumping is often the method of choice. Operators are familiar with the pumps' operation, which can be a visible and efficient artificial lift option for shallow wells, similar to those in the Mississippi Lime. However, because of the additional challenges of unconventional plays and the operators' requirement to accelerate the production of horizontal wells, sucker rod pumps are not always the best option for operation across the whole well life cycle.

For an increasing number of applications, operators are installing ESP systems early in the life of the well, sometimes immediately after drilling out the fracture plugs. ESP systems are used as a transitional artificial lift method until they are replaced with a sucker rod pump for the late life cycle of the well. Upon withdrawal from the well, the downhole components of the ESP are inspected and repaired as needed, then transferred to the next well on transitional artificial lift.

Well cleanout of long horizontal sections is a challenging task, and often, the ESP is used to complete the cleanout operation. However, the high, sustained production of abrasive solids in the well can shorten the run life of the pumps. When the volume of sand and other foreign materials is too large to be transported with the fluid stream, the pumps, and sometimes several joints of tubing above, become completely plugged shortly after the installation.

Fit-for-purpose pumps designed with abrasion-resistant radial bearings and stage materials, coatings and compression construction components are successfully extending the run life of ESP systems in this environment, as long as the sand can be carried with the produced fluid. Real-time surveillance and optimization service and appropriate operational procedures complement the system and maximize the effectiveness of the artificial lift in line with the operators' goals.

New technologies are rejuvenating old formations. As operators look to tap the tremendous potential of the Mississippi Lime, they are relying on advanced artificial lift methods to boost flow rates and overcome the challenges of multiphase production, ensuring the long-term viability of this important and prolific play.

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