Gas Lift Proving Effective In Gas Wells

By Robert P. “Boots” Rouen

SUGAR LAND, TX.–Gas lift has not historically been used in natural gas wells. But a combination of experience and opportunity over the past decade has led to advancements in gas lift technology that represent cost-effective and viable options for gas wells. As a result, a unique new artificial gas lift system has been developed that has field-proven results in dewatering and dramatically increasing production for liquid-loaded gas wells.

The system incorporates standard gas lift technology in an innovative, yet simple completions architecture that enables gas lift across long perforated completion intervals below a production packer. The system was developed in the field through an evolution of applying and modifying conventional gas lift methods and technology, so that gas could be injected below the production packer, deep in the perforated zone, where well-killing liquid loading problems occur.

Every gas well has a critical gas velocity required to effectively transport liquids from the well bore. When a well falls below this critical rate, liquids settle and build in the bottom of the tubing, decreasing production and often eventually killing the well.

Why gas injection? In general, gas lift has a number of benefits over other artificial lift methods. It is the most flexible, forgiving and cost-effective option. It can be used in remote locations, with highly deviated wells and wells with multiple completions. It performs reliably where sand is a problem and in high gas-to-liquid ratio (GLR) wells, regardless of depth. It is a good high or low volume option.

For gas wells in particular, continuous flow gas lift is the only artificial lift method
that fully uses the energy from the produced formation gas. In traditional applications, gas is injected continuously into the production conduit to the maximum possible depth based on the available gas pressure. It provides an extension of the natural gas flow by supplementing the formation with additional high-pressure gas.

In addition, gas lift helps the liquid-loading problem common in gas wells by aerating the liquid and reducing the weight of the fluid column. The injection gas mixes with the produced well fluids and decreases the flowing gradient of the mixture to establish additional drawdown, improving the flow from the formation into the well bore. Gas lift also increases the velocity in the production conduit to maintain the critical velocity needed to move the fluids to the surface and helps prevent liquid loading. But if the gas cannot be injected deep in the perforated interval, below the production packer, liquid loading can still become a problem in many wells.

**System Design, Benefits**

The new gas lift system was designed to address the liquid loading problem in the perforated zone. The ability to inject gas through the packer and deep into the perforated zone means reduced bottom-hole pressure and increased drawdown, thereby increasing the critical velocity to move the water up the hole and out of the well (in water-drive reservoirs, drawdown is typically 50 percent, but it is common to reach 70-80 percent drawdown with the new gas lift technology).

The system employs a series of gas lift components in tubing strings above and below a dual-ported or parallel flow production packer (Figure 1). The string above the packer uses conventional side-mounted mandrels. The lower string ranges in size from 1½ to 2½ inches, depending on casing and packer sizes, and features internally-mounted gas lift mandrels and valves (required for operation below the packer) sized for the tubing. The end of the injection tubing is capped with a bull plug.

The packer itself is a standard, field-proven design that has been modified with two parallel ports—one for the production tubing, and one for the injection tubing. The injection port was opened to a larger diameter to avoid pressure drop through the packer, which allows adequate gas volume to lift the well in the perforated zone.

The system operates in all three standard casing sizes, 4½, 5½, and 7 inches. All three sizes of the system have been tested extensively with excellent results. The system has been further refined to include the use of 2½-inch tubing below the packer for all three casing sizes. Originally, 1½-inch tubing was used, but the larger diameter takes up more cross-section, reducing the amount of injection gas needed.

The system was designed for use in liquid loaded gas and coalbed methane wells, and for gas-lifted oil wells. It can be used in all three standards casing sizes in any well configuration, and can be particularly beneficial in:

- Oil and gas wells with low bottom-hole pressures;
- Gas wells with very low productivity indices (PI);
- Gas wells with long perforation intervals;
- Wells with bad casing;
- Wells with liners and small casing completions; and
- Below deviations where it can be risky to run packers.

The system is installed with a traditional workover rig. It can be particularly cost effective in gas wells, because it is typically an addition to the completion already installed in the well.

The technology offers all the general advantages of gas lift, while also providing the ability to lift below the packer across the perforated zone. In addition, it keeps injection pressure off the formation, provides the infrastructure and ability to chemically treat in perforations, and provides the ability to produce all zones in the well bore.

**Evolution Of The Technology**

Using gas lift on gas wells was not common practice until about 10 years ago. The genesis of this system stems from a gas-driven rod pump that was used in wells with low bottom-hole pressures to reduce bottom-hole pressure to zero to help the wells flow. This method was effective and produced good results, but elastomers and other key elements were not as advanced as they are today, so a lot of time was spent pulling the pumps from the hole and repairing them.

The next step in the evolution was dual annular gas lift injection, which involved running 1½-inch tubing in the existing 2½-inch production tubing and flowing gas back up both the annulus formed between the two tubing strings, and the annulus between the 2½-inch tubing and the casing. This method was first used to de-water coalbed methane wells in the Black Warrior Basin in Alabama, and was later used in deeper intervals for some gas wells in East and South Texas.

The gas wells of East Texas provided motive and opportunity, so to speak, for using gas lift on gas wells. The fracturing technology commonly used to improve production on wells in the area also produced a great deal of water, with two main outcomes. First, there were many wells of this type with a good deal of production left in them, but they were shut in by excessive liquid loading. Second, conventional mechanical lift methods, such as plunger technology, are not effective in these highly liquid-loaded wells.

Progression moved to casing flow injection, where the gas was injected down the production tubing and back up the casing annulus. This method allowed injection into the perforated zone and yielded some good results, but it required a tremendous amount
of gas to be effective.

The next step was a large one toward the current design. Coiled tubing fitted with internally-mounted mandrels was run inside existing pipe so that gas could be injected deep in the perforated zone, through the tubing, and back up through the pipe. Specifically in one example, 1¼-inch coiled tubing fitted with three internally-mounted gas valves in the perforated zone was run inside existing 2¾-inch pipe. The well featured a long perforation interval of 2,538 feet (from 9,658 to 12,196 feet TD) and was a rigorous test of this method in such a long and deep perforated interval. The results were quite good, restoring production from this previously dead well to 400 million cubic feet a day.

Many more wells were lifted using this coiled tubing-in-pipe configuration with similarly dramatic and consistent results, thereby proving the basic design concept for the new system. But to make the system more efficient and cost effective, it had to be done using conventional, off-the-shelf gas lift technology without the need for a coiled tubing unit. This led to the development of the system.

Case Studies

The system has been tested extensively in all available casing sizes for many configurations and operating environments. Case studies from actual field applications provide some details of the operating environment, system configuration and general results.

In one case study (Figure 1), the system was used on a gas well in Southeast Kilgore, Tx., with a TD of 10,600 feet and where the perforated zone extended from 9,636 to 10,600 feet. The well had previously been on plunger lift and soap injection, and neither improved production.

The new system was run in 4½-inch casing with 2½-inch tubing above the packer and 1¼-inch tubing with 1¼-inch internally-mounted mandrels below the 4½-inch bypass packer, which was set at 9,598 feet. Prior to injecting with the new system, daily production rates were 40 barrels of water and 43 MMcfd of gas. Current production rates since injecting with the new system show a 50 percent increase in water (to 60 bbl/d), 1.5 bbl/d of oil, and a five-fold increase in gas production (to 225 net MMcfd), with an injection rate of 200 MMcfd.

The production chart (Figure 2) shows that early production was erratic. As noted, the operator upgraded the production system and replaced a pipeline. Following that upgrade, gas and water production increased as expected, in a predictable manner, with the new system increasing critical velocity to remove liquid from the well bore and increase gas production.

In another application (Figure 3), the system was installed in a gas well in Wyoming with a TD of 13,340 feet and a 1,002-foot perforated zone (from 12,338 to 13,340 feet). The well had previously been on conventional gas lift with no production improvement. Again, because of its unique configuration, the system can inject gas across long perforated intervals deep into the well, where liquid loading problems occur.

The new system was run in 7-inch casing with 2½-inch tubing above the packer and 2½-inch tubing with 2¼-inch internally-mounted mandrels below the 7-inch packer, which was set a 12,090 feet. Previous production rates were 79 bbl/d of water and 146 MMcfd of gas. Since injecting with the new system, production rates have doubled to 159 bbl/d of water and 367 net MMcfd/day of gas with an injection rate of 300 MMcfd.

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