Combining Plunger Lift and Gas Injection in Low-Rate Gas Wells

Plunger lift and gas injection are two common methods used in gas wells to unload liquids. As the productivity of gas wells in the western Canadian sedimentary basin continues to decline, these methods used alone are no longer sufficient for many wells. Combining plunger lift with gas injection by use of newly developed and innovative tools and techniques can provide a solution for many low-rate gas wells that otherwise could not be cost-effectively produced.

Introduction

The maturing of the western Canadian sedimentary basin and the decline in average gas-well production rates, combined with strong demand and high commodity prices for natural gas, has led to a need to find ways to produce gas wells at lower and lower rates before they are shut in and abandoned. As a result, tools and techniques to remove liquids from these gas wells have become increasingly important.

Both plunger lift and gas injection are techniques that have been used for many years to remove liquids from gas wells. Although there are several synergistic effects that occur when plunger lift and compression are combined, there also are a number of operational issues that make it challenging to combine the two technologies.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 100590, "The Tools, Techniques, and Advantages Involved in Combining Compression and Plunger Lift in Low-Rate Gas Wells," by ***R.A. Schmitz,*** *SPE, and* ***G.D. Steele,*** *SPE, VaporTech Energy Services Inc., prepared for the 2006 SPE Gas Technology Symposium, Calgary, 15–17 May.*

Liquid Loading

Liquid loading in a gas well is caused by the inability of the produced gas to remove the produced liquids from the wellbore. The point at which liquid loading will begin to occur in a producing well can be estimated by calculating the critical gas velocity, which can be translated into a critical gas flow rate. Various methods are available to estimate the critical gas flow rate, but the most important variables that determine the critical gas flow rate are gas production rate, inside diameter of the tubulars through which the gas is flowing, and the pressure and temperature of the gas.

If the produced gas is flowing at a rate less than the critical rate at any point in the wellbore, liquid loading will occur. The produced liquid will start to accumulate in the wellbore, which often leads to erratic slugging flow and to decreased production. Eventually, the liquid buildup will cause the well to cease production entirely.

Plunger Lift

Fig. 1 shows a basic plunger-lift system. The primary function of the plunger is to provide a semisealing interface between the gas and the liquid, enabling the gas to lift the plunger along with a slug of liquid. The gas flow rate required for a plunger-lift system to function effectively depends on many of the same factors as the critical rate, but it also is affected by other factors such as the amount of liquid produced, the depth of the well, and the sealing efficiency of the plunger. As a result, prediction of gas-well performance with plunger lift is not an exact science.

Gas Injection

The injection of gas reduces the flowing pressure, which increases the productive capacity of the well. The increase in production depends on the inflow-performance relationship for the individual

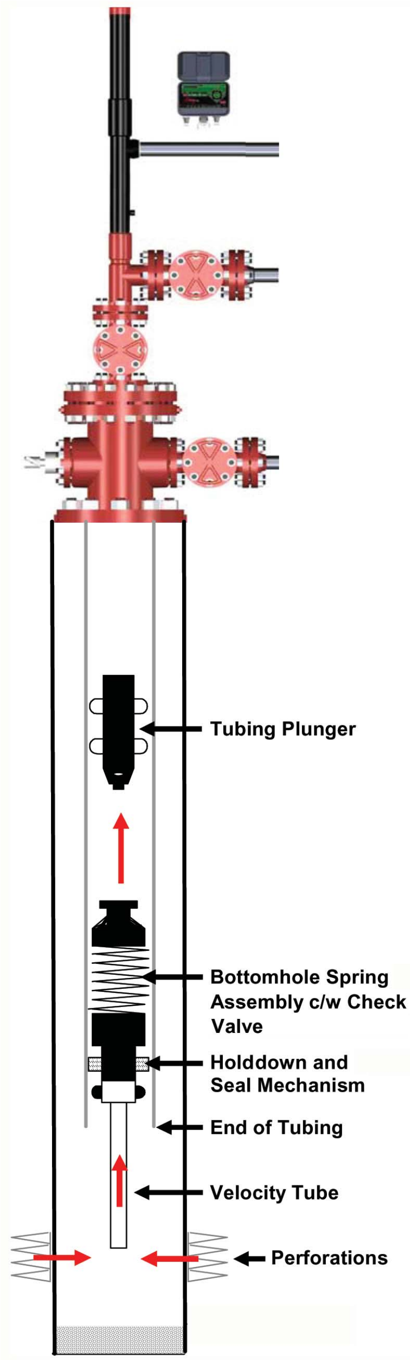

Fig. 1—Basic plunger-lift system.

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well. At the same time, decreasing the flowing pressure of the well decreases the critical gas flow rate. Gas injection or recirculation can be used if a well-site compressor or some other source of higher-pressure gas is available. In this scenario, some of the gas discharged by the compressor would be recirculated down the annular space of the wellbore to mix with the gas being produced from the reservoir to increase the gas flow rate up the tubing to a flow rate greater than the critical gas flow rate. As the well continues to decline, increasing volumes of injected or recycled gas are required to maintain a sufficient gas flow rate in the tubing, with the practical limit reached at the point where the net gas being produced no longer justifies the costs involved in compressing the produced gas plus the recycled gas.

Combination

The synergistic effects of combining plunger lift with gas injection and with compressed-gas recirculation can be shown by an example scenario. Starting at some initial conditions with the gas flow rate less than the critical rate, plunger lift could be installed to enable the well to continue to produce at a lower rate. Compression then could be added, resulting in decreased flowing pressure and increased production. When the well reaches the point where significant shut-in time would be required to cycle the plunger, gas recirculation could be implemented to produce the well at even lower rates until the economic limit was reached. Depending on the specific application, gas recirculation could be used on either a continuous or an intermittent basis.

Operational Challenges

Numerous operational challenges can arise when combining plunger lift and gas injection. For example, if a conventional plunger-lift tool is used, the well must be shut in for a significant amount of time, especially deeper wells, to allow the plunger to drop to the bottom of the well because a conventional plunger cannot fall against the flow of gas. During the shut-in times, there is no flow from the well and thus no feed for the compressor, which can be difficult to handle with a typical compressor installation.

Two tools can be used to address this challenge. The first is the use of a "fast-trip" plunger. These plungers are designed to fall against the gas flow and require very short shut-in times (less than 10 seconds). They also fall very quickly and are able to travel to the bottom of the well in a relatively short time period. When this type of plunger is used, the very brief shut-in often can be accomplished with minimal disruption to compressor operation. Significant gains in well productivity often can be achieved, as well as an increase in producing time.

The second tool to manage shut-in times is a control system on the compressor that enables the compressor to handle extended shut-in periods without the need for start/stop operations. There are numerous options available, depending on the shut-in time required and other application-specific factors. For example, for short shut-in times, a variable-speed drive system that can slow down the compressor may be sufficient. For longer shut-in times, a recycle system that is capable of cooling the recycled gas sufficiently may be an option. However, such a system has the disadvantage of wasting a significant amount of energy compressing the gas that is recycled, and the extra cooling required can add significantly to operational complexity and to capital cost. Probably the best option is to include a system that can "unload" the compressor during the shut-in periods. Such a system enables the compressor to continue to rotate without actually compressing any gas. Because the gas is not being compressed, only the energy required to operate the compressor in idle mode is used, and additional cooling is not required.

Another issue is the speed at which the plunger is traveling when it reaches the surface. As the flowing pressure of the well is reduced, the speed at which the gas and the plunger are traveling increases. At lower pressures, the plunger can be traveling sufficiently fast to cause serious impact damage to the plunger and/or the surface equipment. To avoid this, a control system can be installed that allows some of the flow to come up the annular space. The control system is used to regulate the flow up the tubing to a rate sufficient to operate the plunger effectively. This is accomplished by using a control valve on the annulus to adjust the amount of gas that is allowed to flow up the annular space. This system also has the added advantage that flowing some of the gas up the annulus results in reduced frictional pressure losses up the tubing, lower bottomhole flowing pressures, and an increase in gas production.

Other Tools

There is a great deal of work being done on new and innovative tools not yet in the public domain to help in the effort to maximize recovery from low-rate gas wells. While the concept of unloading compressors is not a new one, unloading systems that can be used with plunger-lift systems are only now starting to be developed and improved. Different types of compression (e.g., reciprocating compressors vs. rotary-screw compressors) operate in very different ways, and different systems are being developed to operate each of these compressors in an unloaded state for extended periods of time. There is work being done as well on the challenges involved in controlling the plunger operation and the compressor simultaneously.

Tool-development work also is being done in the area of gas recirculation. In a well where there can be no communication from the tubing to the annulus (e.g., a sour well with a packer installed), gas recirculation would not be an option. One tool being developed to address this situation requires an annulus pressure that is higher than the tubing pressure before it will open, ensuring that gas can flow only from the annulus into the tubing and not in the opposite direction. It includes a sealing mechanism and could be set across a sliding sleeve or a perforated section of tubing. In the sour-well example, because no sour gas would be allowed in the annular space, compressed sweet gas could be injected down the annulus, to enter the tubing through a one-way flow valve to supplement the gas production from the well so a plunger could be cycled effectively.

Another tool being developed to improve the application of gas recirculation is what might be termed a "fan packer." This tool is meant to be run on wireline and landed below the bottom of the tubing and above the perforations. The fan packer can be thought of as an upside-down umbrella that would spread out and provide a seal against the casing like a packer when flow was initiated down the annulus. An example of the application of this tool is a situation in which simple gas recirculation would result in significant losses into the formation. Depending on the application, this tool also could be used in conjunction with the one-way-flow-valve tool for intermittent operation instead of continuous gas recirculation. JPT