

HOW TO INCREASE REVENUE IN GAS-LIFT APPLICATIONS

All facilities are under mounting pressure to maximize revenue and improve efficiency. For many applications, installing intelligent valve technology can lead to significant increases in productivity with minimal initial investment and short payback periods. This is especially true in the oil and gas industry.

In gas-lift applications, standard manual valves typically used result in inefficiencies, while complicated automated systems can be difficult to install and expensive to maintain. However, installing integrated automatic flow control systems can boost oil production and reduce gas usage in such applications without the inefficiencies of manual valves or the complication and expense of automated systems.

Installation costs for these integrated flow control systems can be realized in a matter of days and, over time, revenue can increase dramatically.

GAS LIFT INCREASES OIL PRODUCTION

Gas lift is a process by which gas, usually natural gas, is injected through a tubing-casing annulus. The process is not new—it was used in wells in Pennsylvania as early as 1864. In those early days, the working fluid for the gas lift was compressed air. Later, natural gas was used. While many modern gas-lift applications use automated gas injection, some continue to use manual control of gas injection.

For gas lift processes, a casing pipe is drilled down into the oil deposit at depths of up to 15,000 feet. The casing surrounds a second, tubing pipe, which creates a space between the two pipes called the annulus. Pressurized natural gas, which in most applications is a

Today's industry needs to use every available means to increase productivity and decrease costs. For gas lift processes, a tool for accomplishing that goal is to use an integrated flow control system.

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byproduct of the production process, is pumped down through the annulus at pressures typically near 2,000 pounds per square inch with higher pressure sometimes used as needed for the specific application. This injected gas aerates the oil-water fluid and reduces specific gravity. The formation pressure is then able to lift the oil-water column and force the fluid out of the well bore (Figure 1). To prevent waste, the gas is recovered from the oil.

The amount of gas injected to maximize oil production varies from well to well based on the well's geometries. The amount also varies over time because of changing well conditions. Too much or too little gas leads to inefficient production. The wrong amount also can cause upsets, such as surging and slugging, which in turn cause inefficiencies. The result is less-than-optimal oil recovery and injection of excessive amounts of gas.

Gas lift is useful throughout the life of a producing well—it can be used continuously from start-up to improve efficiency but is most often implemented as the well ages to improve production when less reservoir pressure is available to lift the stream.

MANUAL CONTROL INCREASES COSTS

Standard manual gas-lift valve configuration includes a manual choke valve on the gas injection line (Figure 1). This valve controls the flow of gas down through the annulus, the gas-lift mandrels (retrievable side-pocket mandrels are typically part of a gas injection system) and the valves. These poppet-style, down-hole, on/off valves open on differential pressure. They are part of any gas-lift system, whether that system is operating in manual gas-lift mode with the manual choke valve or whether the gas-lift operation is set up with an automatic flow control system.

As the gas begins to flow, the top gas-lift valve opens and the fluid lifts as the gas bubbles travel upward (Figure 1). As the gas continues to travel down the annulus, the second gas-lift valve opens and the first valve closes. This sequence continues until all of the gas exits from the bottom valve, at which point oil is flowing from the formation reservoir into the tubing, and up and out of the well.

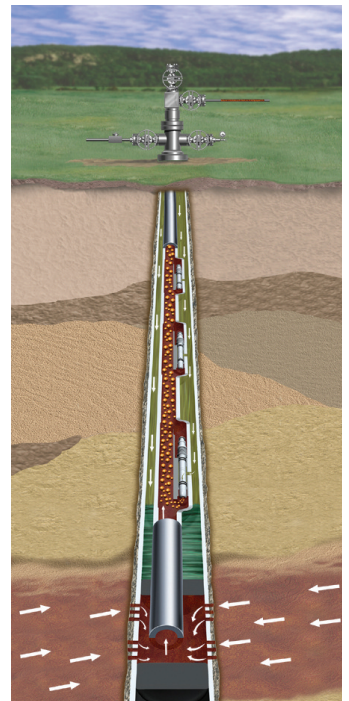


Figure 1. Formation pressure lifts the oil-water column and forces fluid out of the well bore.

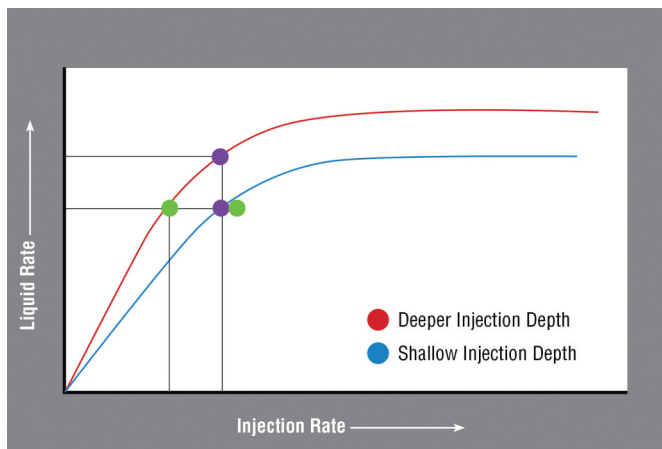


Figure 2. Injection vs. recovery

As the gas injection rate increases, so does the liquid recovery rate. However, there is a point of diminishing return (Figure 2). While the recovery rate climbs beyond this point with additional gas injection, the amount of gas (and therefore energy) required rises rapidly, while the recovery rate increases only minimally. This situation results also because the ratio of the gas being recovered becomes excessive and displaces the oil, causing fundamental changes in the flow inside the tubing. The goal in this application is to operate at the knee of the curve, at which point a maximum amount of oil can be retrieved using a minimum amount of gas.

In a manual gas-lift system, the manual choke valve is semi-fixed, meaning that an operator sets it periodically, usually with a handwheel. As the inlet gas pressure or the back pressure to the

this wide variation and subsequent upset is significant. These swings in pressure can be due to compressors going up or down, wells being shut in or started up, and other anomalies that periodic manual manipulation cannot account for.

If the pressure shifts far enough, the gas-lift poppet valve may close until the pressure builds and relieves. When this happens in spurts, it causes surging and intermittent flow. Following a gas burp, the well then begins to flow with a slug of liquid—a process that is repeated constantly until the pressures change or the manual choke valve position is reset. The result is a migration from optimal liquid flow rates as well as inefficient use of natural gas. Excessive slugging also can cause pressure spikes in the well strata, culminating in damage to the well.

Over the long term, manual control results in a wide variance of natural gas

injected into the well (Figure 3). The barrels of oil produced will vary significantly over time (Figure 4), and surging (intermittent flow) from shifting gas injection rates can also occur. These conditions lead to excessive use of natural gas, which increases costs and reduces oil production, thereby decreasing revenue.

Field data has shown that these fluctuations in flow rate in a manual choke valve can vary by as much as 40% of desired flow rate. As with any process dependent on flow rates, the potential impact of

AUTOMATIC CONTROL IMPROVES ON MANUAL

An operating oil field is a dynamic, interwoven system—what happens in one well impacts every well in the field. If one well is shut down, idled or brought online, the dynamics of the entire system can change. Consequently, to maximize oil production, each gas-lift system now requires different pressure or flow rate. To achieve smooth, efficient operation, the change in down-hole gas injection must be seamless. This is why balancing a field at optimal performance with manual valves is impossible—each change that occurs results in changes to every other well in the system.

One way to smooth out the process of controlling the flow of injection gas in gas-lift applications is to use automatic control coupled with a conventional system of sensors, an automatic control valve and a controller.

The heart of a conventional automated system is a control valve (Figure 5), which automates the process of setting the injection rate. The control valve is coupled with an automation package that consists of a flowmeter, a pressure

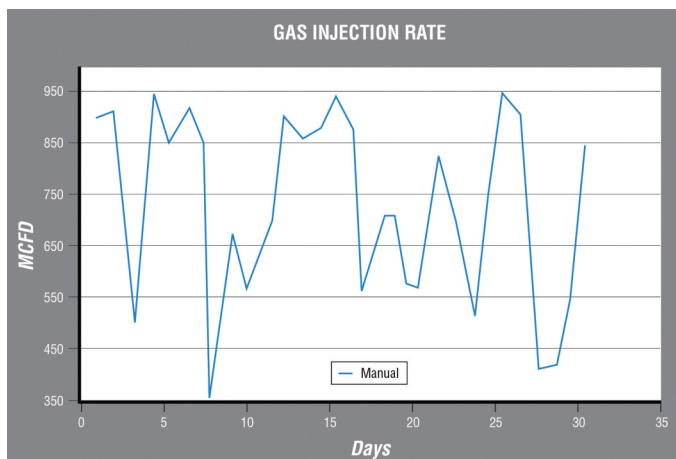


Figure 3. Long-term variance of natural gas produced

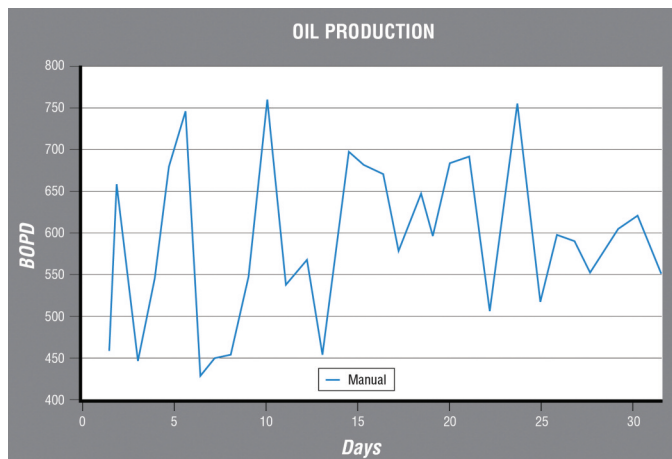


Figure 4. Long-term variance of oil produced

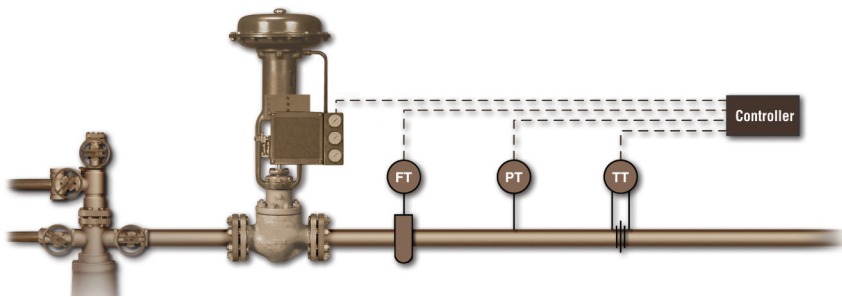


Figure 5. Conventional automated system

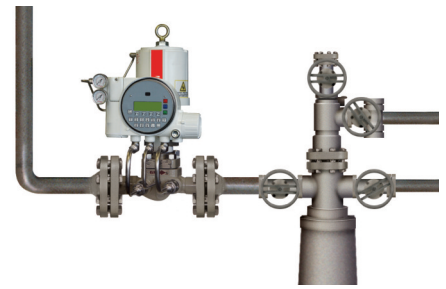


Figure 6. Automatic gas lift system

transducer and a temperature sensor, which are all equipped with transmitters and typically connected to a distributed control system (DCS) or a programmable logic controller (PLC). This process allows operators to control and monitor these critical indicators remotely and change the flow control of the injection gas accordingly.

Automating the injection of natural gas into the down-hole annulus has numerous advantages over manual control. For example, automation stabilizes the natural gas flow, leading to less slugging of the process and a more consistent flow of oil to the surface. This is accomplished by controlling the flow of natural gas down the well rather than having the choke valve in a fixed position, pressure on a natural gas regulator or a control valve.

Eliminating surging and intermittent flow means less maintenance because it becomes possible to maintain the optimal flow rate for each well in the system. The increase in overall production of oil and decrease in overall injection of gas not only helps the

bottom line, but also reduces the environmental impact.

INTEGRATED CONTROL MAXIMIZES REVENUE

Conventional automatic control systems are superior to manual control in gas-lift applications. However, they require complex, multiple installations of equipment that is expensive to put in place, program, maintain, tune and communicate with. Conventional automation systems also add significant weight and require more space.

Conventional automation also requires multiple instruments so each one of those instruments must be installed and connected to the other instruments. To provide maximum performance, communication between these instruments must be established, and the entire system tuned. All of this takes time and requires training, experience and significant resources. These costs and the resulting production delays are the most common reasons wells are not updated to automatic controls.

Facilities should consider installing

an integrated gas-lift automatic gas injection system to optimize the gas-lift and realize the largest return on investment (Figure 6). An integrated solution contains all elements needed for flow control in one package.

Such a system contains a control valve, pressure and temperature sensors and an on-board PLC. Any such system requires compensation for turbulence. A properly tuned system correctly measures flow with elbows installed just upstream or downstream. Using calibrated pressure measurements and valve position information, the flow rate is calculated, then the system can control the valve position to maintain optimal flow rate (Figure 7).

Typically, the connections required for an integrated solution are supply pressure (instrument air or natural gas), power (24 VDC) and a 4- to 20-milliamp setpoint signal. Such a system also can provide valuable information on pressures, temperatures, flow rates and other data that can be used to optimize the field along with each individual well.

Once all the wells in a system are on

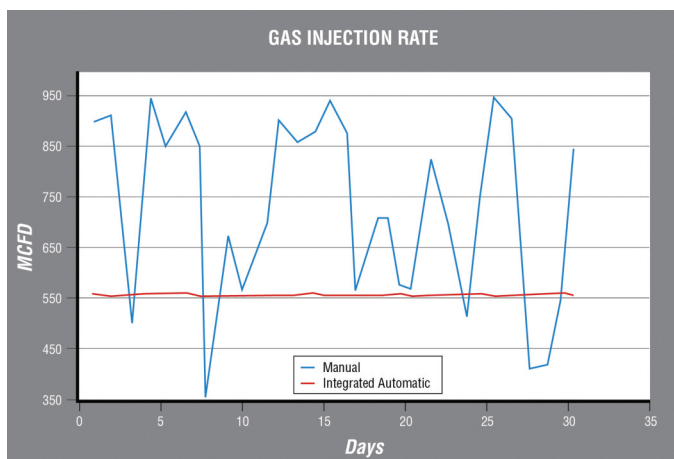


Figure 7. Injection rate—manual vs. automatic

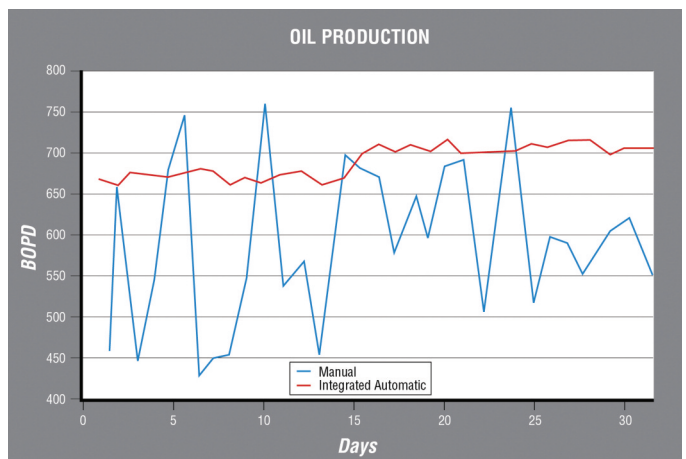


Figure 8. Production—manual vs. automatic

automated flow control, each can be controlled individually. The field is optimized because changing the set point of one well does not affect the set point of the rest of the wells. This optimization helps to balance the use of natural gas, lowering the overall gas usage and increasing field oil production (Figure 8).

Unlike conventional automated gas-lift natural gas injection systems, an integrated system fits into existing piping through replacement of the manual choke valve with a single piece of equipment. This is in contrast to the multiple pieces and separate network of a conventional system. By using one piece of equipment installation, time and complexity is significantly reduced. Most integrated solutions are also pretuned and ready to receive a setpoint signal, and some include advanced diagnostics to troubleshoot any system issue. Often, the face-to-face dimensions of the integrated solution match the manual valve, which eliminates the need for re-piping.

As a consequence of the simpler

installation and setup, the facility reduces downtime and minimizes lost productivity, which directly affect the payback period of the installation. No complex systems for data acquisition and transmission are required, speeding up control to eliminate the surging and slugging still common with conventional automated gas-lift systems.

The effectiveness of such a system can be seen in an oil and gas facility in Angola. There, an integrated system was installed at a rate of eight hours per unit and cost about \$47,000, which included lost production. However, because the gas injection rate and tubing pressure in the pipe casing were stabilized, the facility raised overall production by 465 barrels of oil per day while reducing gas usage by 200 million cubic feet per day. Once the entire field was automated, oil production was further enhanced as the field was tuned for optimal performance.

This chain of events generated a revenue increase of \$23,250 per day, enabling the facility to realize initial return in two days. Over the year, the

incremental increases in revenue topped \$8 million.

INTEGRATED CONTROL VALVE SYSTEMS BOOST ROI

With "easy oil" diminished and the price of oil trending upward, it makes good engineering and business sense to optimize the gas-lift process by installing an integrated flow control gas injection system over manual choke or conventional automated control valve systems.

This is because an integrated solution decreases the consumption of gas and energy while increasing the recovery rates of the oil and gas. Under the right circumstances, a return on investment can be realized in a matter of days, paving the way for a boost in revenue and reduction of costs. **VM**

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