Optimizing Chemical Injection of Natural Gas Wells

The use of intelligent controls can optimize the injection of chemicals and natural gas production from wells. Rather than the use of a timer to energize chemical pumps, the controls run the pumps based on well and line conditions.

Maintaining Well Production

In newly drilled wells, the oil, water, and gas fluids usually flow freely to the surface through the well casing. When the fluid flow drops to a point known as the critical flow rate, an oil/liquid slug often forms and blocks further flow. Operators can then install a concentric tube within the well casing. The narrower tube increases the flow velocity to restore a free flowing well.

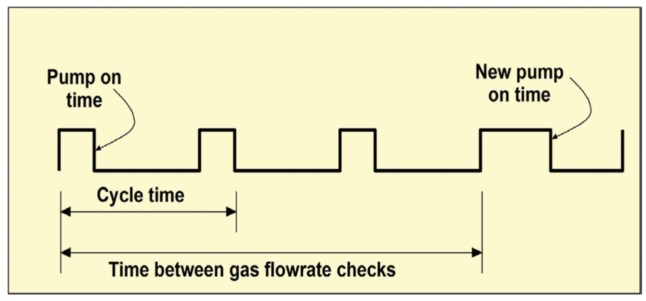
With time, however, the natural pressure within the well reservoir begins to fall. Production declines, following a well-known decline curve. Backpressure resulting from the buildup of an oil-and-water slug in the tubing slows production or even brings it to a halt.

Companies may resort to one or more strategies to improve production. Some of these techniques include:

•Intermittent Lift-a main valve completely shuts off flow through the production tubing, permitting bottom hole pressure (BHP) to build. At some point the BHP builds sufficiently to overcome the liquid slug backpressure. The valve is opened and flow restarts, lifting the liquids out of the wellbore. Flow will continue until liquid accumulation causes bottom hole pressure to drop off again, decreasing the flow rate.

•Plunger Lift Systems-here a piston-like plunger sits at the bottom of the well tubing and serves as the interface seal between liquid buildup in the tube and the BHP below. Again, the main valve shuts off all flow through the tube until the BHP below builds to a level that's about 1.5 times the line pressure, and can lift the plunger to the surface. The plunger brings the liquid oil and water with it, relieving the liquid backpressure to permit gas flow.

•Gas Injection-various techniques introduce gas to the bottom of the well casing. The gas supplements the BHP, helping to lift liquids and/or plungers in the tube to the surface.



Using pump on/off time as a proportioning technique. Pump on time increases as gas flow decreases.

Solar chemical pumps are environmentally friendly and suit remote locations with limited or no power. (Photo courtesy of TXAM Pumps.)

•Submersible Pumps-positioned at the bottom of the well and typically electrically powered, these units artificially lift liquids to the surface to increase gas production.

Chemical Injection

Another technique to improve well production is to inject a surfactact-based chemical into the well that foams and lightens the liquid slug to the point the BHP is sufficient to restore flow.

The foamer reduces the density and surface tension of the liquid slug because of entrained gas. The lower density results in a reduced critical velocity. Often, however, companies simply time the injection of the foaming chemical with no regard to actual well conditions. A better way: set up the controls to inject more surfactant chemical as well flow decreases.

As an example of how simply timing the injection can go wrong, the first installation of this control strategy cut chemical usage at a well by 85% and increased production by 35%. This extraordinary result indicated that the timing system was injecting too much chemical.

Too much or too dense a foam can increase friction in the production tube, resulting in a foam block. A foam block defeats the whole purpose of chemical foamer injection. It can also result in foam accumulating at the surface, requiring chemical defoamers. More generally, controls will improve production by 4% or 5% and eliminate any need for defoamers.

Continuous Control

As in the example above, this control strategy operates the chemical pump based on the gas flow rate.

Typically, the gas flowrate measurement is by a differential pressure element such as an orifice, coupled with a multivariable transmitter and flow computer.

The lower the flow rate, the longer the pump will run within a one-minute cycle. The idea is to operate the chemical pump at a rate inversely proportional to the well gas flow. Since the pump is an on-off device, on-off time can be used as a proportioning technique.

For example, suppose the gas flow measures 500 MCF. That flow rate may be considered high enough so that the chemical pump stays off.

The operators can set up several flow set points that trigger the pump on for set times as the flow rate falls.

As the gas flow falls to a set point of 475 CFM, the system may run the pump for two seconds within a one minute cycle.

As gas flow falls further below a 450 CFM set point, that pump may run for four seconds within the cycle, and so on.

The continuous control strategy can be adapted to many other chemical injection operations.

The chemical injection rate can be based on rising or falling well flow rates or even temperature, depending on the chemical and its purpose. The table below shows various well operations that involve chemical injection, along with the appropriate rising or falling control technique.

For example, a hydrogen sulfide scavenger operation would inject more chemical as well gas flow increased to strip more H_2S out. In cold climates some wells can experience the formation of gas hydrates. In this case ice encapsulates the natural gas molecules and tends to block flow. Here the continuous control system would increase methanol injection with falling temperatures.

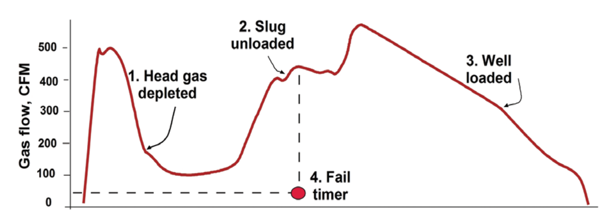
Best practice for chemical injection in a continuous system is to run a capillary tube for the chemical down into the well near the bottom. In this way the chemical immediately exits the tube when the pump is energized, and it begins to interact with the liquid slug.

If the injection takes place at the surface, the chemical will generally fall at a rate of 2500 ft/hour. So it may take several hours for the chemical action to take effect. Injection by capillary tube is mandatory for the batch control system explained below or for injection in combination with plunger lift systems.

Batch Control

In this case the program starts with an open well and the chemical pump off. As the well gas flow drops below a set point, the control system closes the well and calculates a new pump run time based on liquid slug size, the required chemical to foam the slug, and the pump rate. The system turns the chemical pump on for the calculated interval.

After this time interval, the system turns the pump off for a time period set by the user to allow the chemical to mix with the liquid to produce foam. After the mix time expires, the program checks to ensure that the BHP exceeds a set-point prior to opening the well. Once the well opens, gas flow continues until liquids again begin to slow gas flow.



In batch control, a system of flowrate setpoints determines chemical pump on and off times.

Flowrate set points determine when the cap gas is depleted, when the slug is unloaded, and when the well is starting to load up.

The figure shows a system of gas flow set points that determine chemical pump on and off times for a typical batch cycle. While the well is open the flow rate set points are selected:

1. To provide time for the cap gas to be depleted.
2. To provide time to allow the liquid slug to unload.
3. To detect buildup of the slug.
4. To close the well if set point 2 is not reached within a settable timed interval.

Software Control Functions

Totalflow functions for virtually all well-pad control operations have been pre-engineered, including continuous and batch chemical injection. Hardware modules for input/output signals come in DIN mountable enclosures that employ Phoenix contact technology for field wiring. The modules also interconnect with each other to provide the necessary power and interface signals along their bus. Generally, only the enclosure size limits the capacity of these I/O modules. The flexible and modular nature of these systems provides a complete set of proven solutions for the oil and gas industry. The systems are scalable, allowing adaptation for well-pad additions, retrofit, and upgrades.

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