Larry Rhodes
and Russell Brown

BERTHOUD, CO.–The costs for all aspects of operating an oil and gas field have gone up, and the same is true for automation. Producers are striving to find ways to bring these costs under control. One way is to optimize the automation equipment used in the field. In any automation system, the major costs are in purchasing, installing and maintaining the field equipment.

The latest trend in the automation industry is to find a way to reduce the cost of automation. This also has been the challenge for field automation equipment providers as well as automation companies. This is even more important during this economic downturn because producers need to accomplish the same work for less cost.

Automation is a key mechanism for doing this. However, unlike other downturns in this industry, producers are looking to automation providers to deliver the same amount of field automation protection more economically.

Automation has become a more important part of the oil and gas field. Most of the easy oil and gas plays have been found, and what is left is harder and more expensive to extract. To economically produce today's wells, companies must cut their daily production and maintenance costs.

This puts the onus on automation to provide a less expensive and safer way to operate. One of the ways to do this is to combine automation solutions such as in a multiwell pad, or to combine automation for wells, compression and tank batteries.

Pad Automation

Multiwell pad automation is not new. It has been a popular automation method within the coalbed methane community. In most instances, the method for providing multiwell automation was to combine automatic gas measurement at a central distribution point (CDP). In this structure, the wells are drilled in proximity to the CDP, and the gas is piped to the CDP, where a single meter house typically holds all the meters.

Initially, these installations required one meter per well, even though all the measurement was done at a single location. Other equipment was still needed at the wellhead, which also needed automation. The goal of this type of automation was to reduce both traffic to the wellhead and the time required to maintain the gas measurement equipment.

Although the initial attempt was to provide a common automation location, this was only partially successful. The next evolution in providing a common automation location came in the automation equipment.

Automation manufacturers–mostly gas measurement companies–began to develop multitube electronic flow meters. This meant that one piece of hardware could measure multiple gas runs. This was the first real step toward providing a more consolidated automation effort.

One problem that still existed with this design, however, was that the wellhead was still a considerable distance from the CDP, which meant that plungers, submersible pumps, or other equipment was still needed at the wellhead. This also meant that additional automation equipment was needed at the wellhead.

In a number of instances, producers abandoned the CDP design and went back to placing all their automation at the wellhead.

Rockies Gas Rush

Meanwhile, the rush was on in the Rocky Mountains to produce more natural gas. The increase in gas prices made it economical to find and produce previously uneconomic reserves.

On Colorado's Western Slope, one of the major drilling concerns was leaving as small a footprint as possible. The old-school way of drilling single wells and having thousands of individual well sites was unacceptable. This meant producers had to rethink their traditional method. Facing this pressure, the only acceptable method of drilling was directional, where multiple wells were drilled from a single pad in one location. This also meant that all the automation for those wells could be placed on the pad.

With multiple wellheads at a single location, it is possible to consolidate all the automation for those wells. This can include the gas measurement equipment, plunger lift automation equipment, tank battery automation equipment, and other automation equipment. In some instances this all may be the same device.

Traditionally, most automation equipment has had a single function: a gas meter only measured gas flow data, a plunger lift controller only controlled a plunger-equipped well, or a pump-off controller only controlled a pumping unit. Today, manufacturers are expanding beyond their initial expertise and are trying to provide more capabilities within a single device.

There are pros and cons for manufacturers that incorporate more capability into a single device. The obvious advantage is that producers get more automation for less cost. When a single device can measure multiple wells, control the plungers for those wells, and also monitor tank levels and other pad information, this optimizes the producer's automation dollar. The downside is that one piece of equipment now controls all aspects of that pad, and a failure can be considerably more serious and costly.

Realizing Cost Savings

The cost savings for multiwell automation are not a direct ratio. In other words, if a company installs automation around an eight-well pad, it won't save seven-eighths of its automation cost by installing a single piece of automation equipment. Each meter run still requires a multivariable transmitter, which then ties to the single measurement device. If plungers are involved, the well still requires the plunger equipment, and there typically is an electronic controller at the well. In most cases, the devices at the wellhead or meter run then have to be connected to the central processing unit for that type of measurement.

Although there is a definite cost savings to this method of automation, the bigger savings is in centralizing the equipment, which reduces maintenance time and travel costs. Other benefits are reduced environmental footprint and increased safety.

There are disadvantages to consolidating a lot of wells into a single piece of automation equipment as well. If 10 wells are producing into a single EFM and the main processor board fails, all measurement will be lost at that location. If it is a catastrophic loss, all the data will be lost for the month for that location, assuming it isn't regularly downloaded to a central data collection system.

If the device is a multitube plunger controller, it would be possible for all production on that location to stop. If critical pad data, such as tank battery monitoring, is tied to the failed piece of equipment, critical alarming may be lost. This opens the producer to a potential liability and environmental issue.

A compromise to this design is to use more pieces of automation equipment. Some producers opt to use tried-and-true gas measurement equipment to do that job, while they have other equipment to monitor their plungers, and yet more equipment monitors their tank batteries. These pieces of equipment can be tied together on a multiwell pad, allowing them to provide needed data to one another. This way, if one piece of equipment fails, the entire facility doesn't go down.

The other compromise is how many wells are automated with a single piece of equipment. How much production is an operator willing to lose on a single fuse? Each producer has to weigh these concerns and decide what its risk tolerance is when designing field automation systems.

Noble Automation Scheme

The multiwell automation scheme has caught on with producers, and this design is starting to move into conventional oil and gas fields. Northeast of Denver, Noble Energy has begun an aggressive move to automate an older oil and gas field. After acquiring this field a few years ago, Noble implemented an aggressive drilling program, and has since started to add automation to a field that had none.

Although most of its wells are individual locations, Noble has worked to centralize its automation wherever practical. Since a good portion of this area is farmland, the company wants to minimize its footprint in the fields, and bring the flowlines to a central point where it measures the gas, controls plungers, and monitors and controls tank batteries.

With this design, Noble is automating multiple wells at a single location, be it gas measurement or plunger lift control. Information is then sent to its centralized supervisory control and data acquisition system.

Noble has opted to keep gas measurement separate from the other automation equipment, such as plunger lift controllers and tank battery management. This is a common architecture, since most measurement departments need to protect their gas measurement and typically do not want other automation tied to those devices. Additionally, this allows Noble to change and upgrade the wellhead automation equipment as well dynamics change and as new automation technologies are developed.

Noble does deliver all the data from a typical pad site to a single radio. This provides a single point of failure, but only to the radio network, not to the automation on site. The automation equipment on site is designed to work autonomously from the radio system. Thus, if the radio fails, the wells continue to produce. The radio system also is monitored so that any failure will be detected and a technician will respond.

Noble's design provides it with a good cost ratio of automation equipment to well count. With a final well count in the thousands, this design will enable the company to provide a maximum amount of automation while keeping costs in check.

Autonomous Automation

Another example of optimizing automation can be found in the Texas Panhandle, where a major oil and gas producer has taken a new approach in an established oil and gas field. This field has been producing oil and gas for decades. It was automated, but the company needed more information and protection. Its new design has been to consolidate automation equipment within a wellhead tank battery system.

Wells are produced to a centralized tank battery in this field. At the wellhead, which can be relatively close to the tank battery or miles away, there typically is a beam pump unit equipped with a pump-off controller. For safety and production reasons, the company has been focusing its efforts on making the wellhead and centralized tank battery a single, autonomous automation system (Figure 1).

There are two main concerns at the wellhead: monitoring the pump-off controller, and controlling the electrical control panel. The pump-off controller is a specialty automation device that controls the pumping unit, based on detecting fluid down hole. If the controller detects no fluid down hole, it communicates to the electrical panel, telling it to shut off the pumping unit.

This producer has taken this a step farther by replacing the relay-controlled electrical panel with a smart PLC-based controller. The PLC can take a control from the pump-off controller, which instructs it to start or stop the pump as needed.

In addition, the producer now monitors tubing and casing pressures, as well as other critical data such as indications of a stuffing box leak or the presence of hydrogen sulfide. If there are any problems on site, the smart electrical controller instructs the well to shut down and sends an alarm to the host SCADA system.

System Functions

The electrical panel at each of the wellheads in this Texas Panhandle configuration is tied to the tank battery PLC through a spread-spectrum radio. The tank battery PLC monitors all the information at the tank battery, looking at tank levels, monitoring pumps, and checking data from each of the wellhead controllers.

If the tank battery monitor detects a high volume of fluid, it sends a command to each wellhead, telling those controllers to shut down. If a single well has a problem and needs to shut down, it does so and relays that information to the PLC at the tank battery. This data is then relayed to the central SCADA system, allowing the operator to promptly respond and restore production.

This design concept allows the wellhead and tank battery to operate as a small, centralized automation system. It does not rely on the connection to the central SCADA system to provide a connection between the wells and the tank battery. Instead, the system has its own localized radio system and can run even if something takes out a main communications trunk.

The system is designed to shut down any well that loses communication to the tank battery. This information also gets relayed back to the central SCADA system. In a worst case scenario, such as in an ice or snowstorm that knocks out the main radio towers, the field will continue to produce as long as it can within safe parameters.

Automation in the oil and gas industry has evolved to the point that optimization has taken on new meaning. It no longer is good enough to put stand-alone equipment at each wellhead.

In today's oil and gas field, producers are running smarter, and are doing so with their wellheads and central tank batteries becoming integrated pieces. Whether it is a multiwell pad or multiple wells producing into a single tank battery, automation is smarter and works together to help producers better protect their people and equipment as well as become better stewards of the land, and to do so in a more economical manner.❐

BIOS

LARRY RHODES

Larry Rhodes is owner of Insight Automation Inc. and Insight Technical Services Inc. He has worked in the oil and gas automation industry since 1980. Under Rhodes' leadership, Insight Automation and Insight Technical Services have been providing comprehensive field automation solutions, including field automation equipment, radio systems, and SCADA automation software, since the early 1990s.

RUSSELL BROWN

Russell Brown is sales manager for Insight Automation Inc. and Insight Technical Services Inc., and has considerable experience in all aspects of the oil and gas industry. Previously, Brown worked as regional sales manager for Ferguson Beauregard, where he specialized in plunger lift control and automation. Prior to that he worked many years for ConocoPhillips.