

Pad Automation Reduces Fiscal Risk

By Michael Machuca

AUSTIN, TX.—Unconventional shale production has many challenges. Rapid development and deployment of assets, accelerated production declines, and an evolving regulatory environment leave little margin for error and require effectively leveraging technology to achieve economically viable production.

An automation strategy based on surveillance, analysis, optimization and transformation provides a unique opportunity to reduce time to first production; lower operating and maintenance costs; improve health, safety and environmental performance; and increase production and yield in order to maximize the economic viability of the field.

A number of best practices have been developed for implementing an automation strategy for well pad facilities that improve insight into the key variables that impact the health of the reservoir and optimize oil and gas custody transfer. Field-proven solutions enable oil and gas companies to fully utilize measurement and control technologies that go beyond a "good enough" approach and manage facilities effectively. By utilizing innovative technology in a more systematic and cost-effective manner, operators can improve process unit operations and reliability.

With the rapid development of new fields, the variety and availability of facility management data are increasing dramatically in quantity and complexity. Yet, it remains a challenge to find the expertise to filter and interpret data in a timely manner. The complexity of automation integration, combined with managing different service providers, can put projects at risk. Oil and gas operators

need standardized and integrated systems and work practices that will improve capital efficiency, lower project risk, and meet challenging deadlines.

It is possible to use remote automation architecture and capability to transfer information from the field to the office in a way that provides the structure needed to readily access critical information regarding field equipment health, process-unit diagnostics, optimization opportunities, and resource utilization.

Many oil and gas operators are implementing a tiered automation strategy that consists of:

- Surveillance to obtain real-time

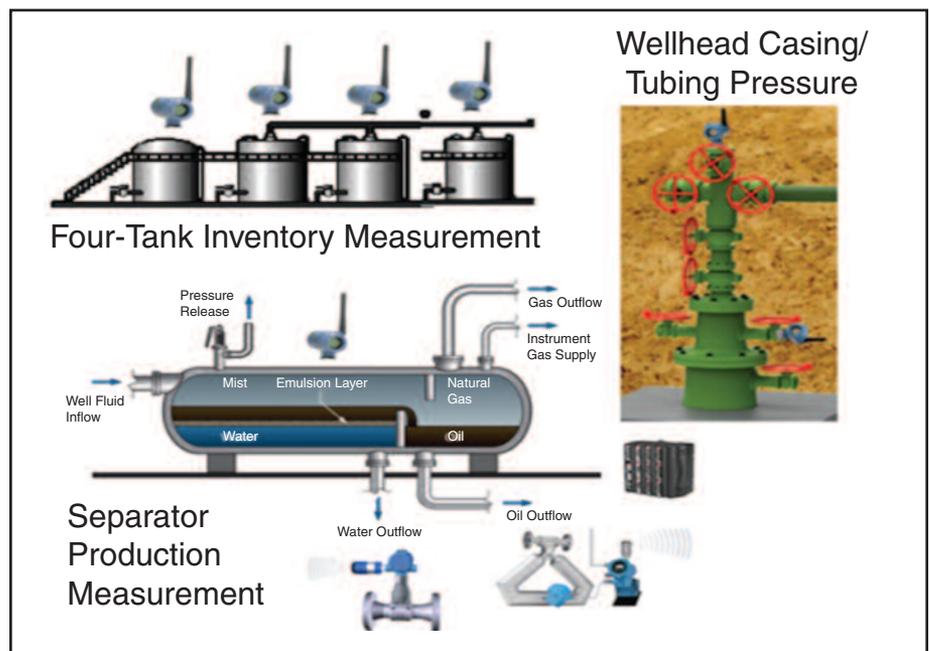
data to improve day-to-day asset management;

- Analysis that adds automatic data validation and migrates data to actionable information in real time;
- Optimizing real time intervention with automatic event detection and handling; and
- Transforming operations with innovative business solutions.

This automation strategy is being utilized effectively to help operators achieve their business goals in shale and other unconventional resource plays, including faster and lower-cost first production; reduced operating, maintenance and com-

FIGURE 1

Wireless Surveillance





pliance costs; optimal production with maximum yield; and better HSE performance.

Real-Time Surveillance

To build a foundation for analysis, optimization and transformation, access to real-time data is necessary to improve day-to-day asset management. This involves installing instrumentation and exploiting the breadth of technologies and telemetry that monitor key process variables in real or near-real time. As a best practice, technology selection should include devices that are designed to work together, offer a simple means of integration, and have diagnostic capabilities that will help to enable data validation and analysis.

A flexible architecture that is scalable and considers wireless technologies will reduce costs and allow for adding instruments as the field changes and more advanced control algorithms—such as artificial lift optimization—are required. Preconfigured software and hardware will increase standardization and facilitate getting production on line faster.

Examples of typical well pad surveillance applications include:

- Monitoring wellhead integrity (casing, tubing pressure, temperature), chemical injection, and sand/corrosion;
- Gathering separator/heater-treater production data and tank volumes; and
- Lease automatic custody control measurement.

Automation Best Practices

Figure 1 illustrates one well automation best practice: wireless surveillance. Being able to get on line quickly is a key challenge in shale development because of fast-paced drilling schedules. Increasingly, wireless technology is being adopted in the oil and gas industry to reduce startup time and installation costs, and to provide a simple way to add monitoring points and access stranded data in remote fields.

One such wireless surveillance project consisted of level measurements in a four-tank battery for inventory management, separator production measurements (pressure, and oil, water and gas flowmeters), and wellhead integrity monitoring (casing and tubing pressures). An economic analysis of the project concluded that taking advantage of a wireless—versus wired—infrastructure resulted in a 66 percent cost savings and an 80 percent reduction in startup time.

FIGURE 2

Real-Time Optimization



Sand production in shale plays also is a challenge that can cause damage to downstream equipment, and in extreme cases can cause erosion that compromises the pressure integrity of the wellhead and gathering pipelines. By taking advantage of nonintrusive, wireless acoustic sand detection, proper choke settings were determined to minimize sand production and the resulting equipment damage. Since the devices were nonintrusive and wireless, they were rotated to different wellheads after the appropriate choke setting was determined, thereby minimizing capital costs.

Real-Time Analysis

After a surveillance foundation has been established, the next step is to ensure the validity of data. As a best practice, operators should consider utilizing devices with diagnostics to confirm instrument health. This provides a means to ensure the integrity of measurement data.

Data management software tools allow easy visualization, trending and analysis in order to improve production planning, schedule proactive maintenance operations, and provide a means for effective remote collaboration and problem solving in order to make informed decisions on field management.

Many shale fields rely on production data measurements from the heater-treater. They may experience difficulty in ensuring accurate allocation accounting without sending someone to the field to validate the data. In many cases, the heater-treater

down-comer level is not controlled adequately. This results in gas exiting the down-comer pipe with the oil.

Many flowmeters will over measure liquid volumes because of this gas, which then must be reconciled with the tank volumes. This can lead to royalty disputes. In addition to the measurement error, the gas is often lost to the tank and flare system, if no vapor recovery unit has been installed.

By using diagnostic capabilities built into Coriolis technology, flow measurement data can be analyzed easily. A spike in oil production, combined with a drop in density and an increase in drive gain, indicates that gas is escaping with the oil during the dump cycle. One oil and gas operator estimated he could recover an additional \$72,000 a day in gas revenue on 1,200 wells in one field by using flow data dump cycle analysis to minimize gas lost to flare.

Fiscal Data Analysis

Accurate flow measurement is very important, since it is used widely for accounting in fiscal and custody transfer applications. The meter must maintain a specified level of accuracy in order to comply with industry standards and regulations. Meter performance is ensured through periodic proving and calibration cycles.

Modern flowmeters can be equipped with diagnostic tools that show deviations from base-line calibration values established at startup or at the calibration facility. In addition, alerts can be generated that show abnormal situations that will



affect meter accuracy.

These analytical tools provide added assurance of meter performance between proving cycles. The fiscal risk of an additional 0.1 percent uncertainty on a metering system going undetected between proving cycles can cost \$1,000 a day, which can be identified easily using analytical tools and meter diagnostics.

With a surveillance system, and data analysis and validation established, it is possible to close the loop and control real time in order to optimize processes and move to rapid intervention (Figure 2). Automating and integrating optimization software support closed-loop control in order to optimize well production, reduce production measurement uncertainty, and automatically optimize the field to ensure production targets are met and reservoir recovery is maintained.

Real-Time Separator

In order to meet production plans and maximize production and yield, reliable and efficient separator operations that provide accurate and timely production data are needed. This requires reliable level measurement, dependable level-control valve performance, accurate pressure control loops, and accurate flow-measurement solutions that have diagnostic insight to detect separator efficiency problems. All of these devices can be integrated in a remote terminal unit with software to perform and automate test sequencing, scheduling, and test validation that can

FIGURE 3

Scope of Integrated Operations Center



be operated remotely.

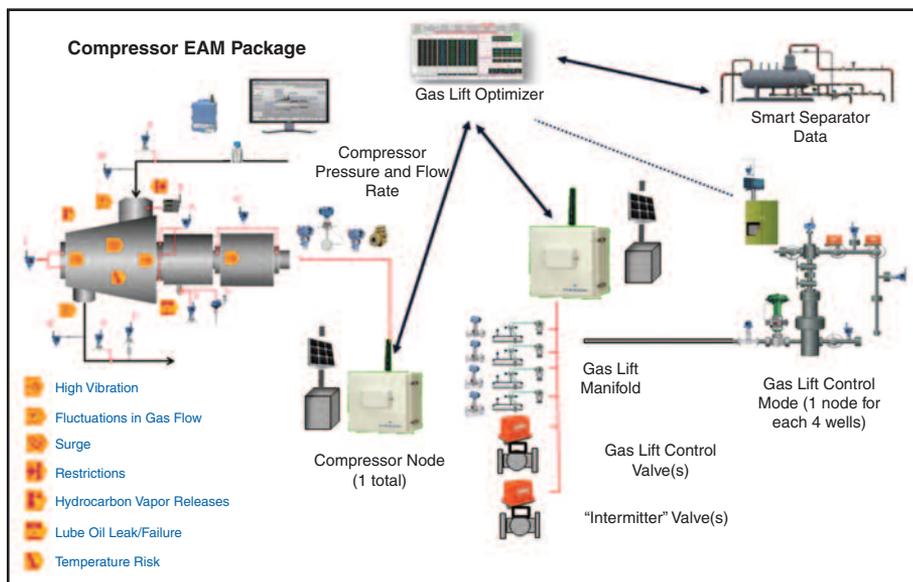
An optimized separator solution allows easy diagnosis of any separator problems. By using these diagnostic tools, one oil and gas operator estimated he could recover 3.4 percent more gas production by minimizing gas carry-under, which would go to tanks and flare. This has the potential to increase gas sales by \$3.3 million a year. In addition, production allocation errors are reduced and more accurate data are available to feed the reservoir model, which results in more

certain reservoir characterization.

Implementing surveillance, analysis and optimization completes the foundation for transitioning to transformation, or using innovative business solutions to change the way a field is managed and operated. It requires utilizing people, processes and technology in a collaborative and innovative way to solve complex business challenges. Oil and gas companies are looking increasingly to integrated operations centers to facilitate collaboration and sharing of information, as shown in Figure 3.

FIGURE 4

Gas Lift Optimization



Gas Lift Management

Optimizing gas lift to ensure optimal hydrocarbon recovery can pose significant challenges. It is difficult to maintain an optimal gas injection rate based on the ratio of the volume of gas injected to the volume of oil produced. Overinjecting reduces profitability because of the added cost of the gas and compression, along with diminished incremental oil production. In the event of limited gas supply, overinjecting in one well potentially starves another well of needed gas, which results in diminished production.

Underinjection simply increases the hydrostatic pressure, which can reduce the ability of bottom-hole pressure to push fluids to the top. With multiple wells and a limited gas supply, it is challenging to distribute gas to the most profitable wells so as to maximize recovery.

Managing gas lift requires integrating



multiple variables across the field, and is a key example of where people, process and technology can come together to provide an innovative solution. In order to maximize efficiency, operators must:

- Automatically optimize gas lift injection flow rates to each well;
- Prioritize gas lift supply to the wells with the highest profitability; and
- Protect the compressor from common failures and trips that threaten gas lift supply.

Figure 4 shows an ideal gas lift architecture for accomplishing these goals. Using this architecture, specialized gas lift optimization software gathers real-time data from the field and tests the var-

ious combinations of lift-gas rates against operating constraints.

The software then converges on an optimum set point and automatically sends new lift gas rates to the automation system either as an advisory or as a new set point. This makes the most of available gas and allocates it to wells where it makes the most money. One oil and gas operator experienced a 16 percent increase in oil production by using this solution. □

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