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Benefits of best practice maximize production and profits

Applying best practices for measurement control means better production management decisions can be made based on more accurate and timely data coming from separators and heater treaters.

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Production management decisions are based on field measurement data and are intended to drive well optimization, sustain reservoir life and result in long-term profitability.

In most oil and gas operations, the production measurement data used to make decisions come from the separator and/or heater treater. By applying proven measurement control best practices, operators can prevent data anomalies, diagnose and avoid production issues, drive uncertainty out of the operation, and maximize production and yield.

The importance of well testing

It's important to know how a well and field are producing to maximize the efficiency of hydrocarbon recovery operations. Most wells start out free-flowing and, over time, decline in production. As the well ages, steps need to be taken to improve oil and gas recovery such as implementing artificial lift, secondary recovery or EOR—all of which add cost.

No matter which technique is used, it is important to understand how much oil, gas and water is being produced from each well to maximize output while minimizing recovery costs. In addition to suboptimal recovery operations, unexpected flow assurance issues like paraffin buildup, water breakout or scaling can cause production decline or result in wells being unavailable for production.

Well testing can determine decline rates and provide the critical data needed to maximize net revenue over time from the well, field and reservoir. In many regions the well measurements taken are used to determine royalty payments to the mineral rights owner and, if these measurements are not correct, it can lead to over- or underpayment, disputes, legal actions and potential fines.

Growing complexity

Traditionally, onshore production measurements were not taken at the heater treater or separator but at the tank. Today operations have become more complex due to the focus on unconventional plays.

Operators are moving toward larger well pads with longer laterals that may have multiple lease holders per pad and tank. Larger facilities are now requiring commingling of production into a single tank or pipeline. As a result, it is necessary to measure production at the separator or heater treater to ensure proper allocation of royalties to the land owner and to fully understand how each well is producing.

It is also common practice to use a test separator that only provides production data on a periodic basis. Production rates must be assumed to be constant until the next test. It is therefore important to get measurements correct during each well test since it may not be checked again for an extended period of time.

Because of these increasingly complex requirements, ensuring proper separator and heater treater production measurements has become increasingly important. Traditional mechanical control and measurement devices are now being displaced with more accurate and reliable technology as well as remote monitoring to provide diagnostic insight.

Separator and heater treater selection challenges

It is challenging to implement best practices for separator and heater treater production measurement. Rapid deployment of facilities, limited information on expected production rates, accelerated production decline and constrained resources can lead to equipment selection that may not be best suited to provide accurate and reliable production measurement.

The separator and heater treater act as a complex flowmetering system where accurate accounting of oil, water and gas is measured. When measurements don't meet expectations, the root causes can most often be traced to:

- Poor level control;
- Inaccurate pressure control;
- Inadequate retention time;

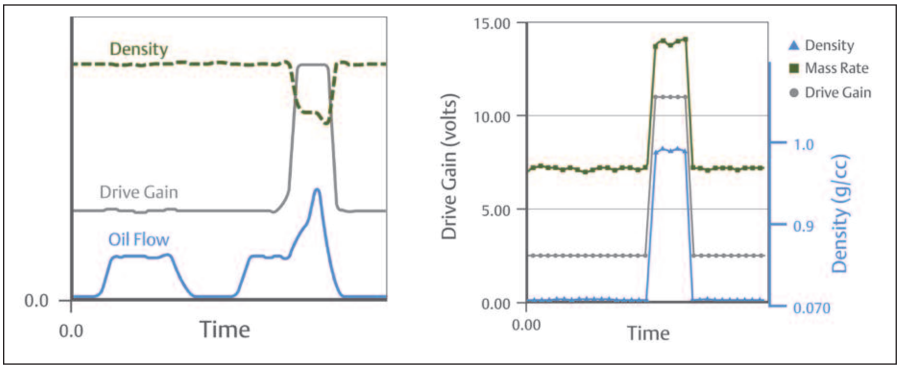


FIGURE 1. Flowmeter diagnostics using density can detect gas carry-under into the oil leg (left) and liquid carry-over into the gas leg (right) of the separator or heater treater. (Source: Emerson)

- Poor temperature control;
- Flow control (valve sizing, stuck dump valves, etc.);
- Flow measurement errors;
- Operating error; and
- Poor well test management practices.

It can often be a daunting task to select the best technology to most effectively manage separator and heater treater operations with so many technologies available to choose from. The unique characteristics of each production field and the constraints that come with operating remote facilities only make this task more challenging.

Best practices

The following are some best practices to instrument and control the separator and heater treater.

Use sophisticated flowmeter diagnostics to detect gas carry-under, liquid carry-over, oil/water contamination and device health: Gas carry-under and entrained gas in the oil that flashes in the flowmeter presents one of the most significant challenges to separator operations. Entrained gas can result in flow measurement errors, can damage the meter and will lead to royalty disputes. In addition, high levels of entrained gas going into the stock tanks will increase costly emissions and flaring and loss of associated natural gas that potentially could have been sold to increase profit.

Some Coriolis flowmeters have diagnostic capability that uses the density and a measure of the energy consumed to keep the meter tubes vibrating called "drive gain" to detect entrained gas in the oil or water leg of the separator or heater treater. A drop in density associated with an increase in drive gain indicates free gas passing through the meter (Figure 1, left).

Similar diagnostic capability also can be used to detect liquid carry-over into the gas leg (Figure 1, right). In this case, it is an increase in density coupled with an increase in drive gain that indicates liquid carry-over.

A third diagnostic capability is realized when a density measurement that is higher or lower than expected on the oil or water leg, respectively, is used to identify oil/water contamination (Figure 2).

For line sizes 2-in. in diameter and larger, ultrasonic meters can use speed of sound and flow profile diagnostics to detect both gas carry-under and liquid carry-over.

Vortex meters have the ability to detect the change on the water outlet from a liquid flow measurement to gas flow measurement. This can be an indication of a stuck dump valve that is allowing high volumes of gas to pass into the water tanks. By taking advantage of flow measurement diagnostic tools, separation inefficiencies can be detected and corrective action can be taken such as adjusting the level controller, separator pressure, temperature or dump cycle flow control to reduce the risk of HSE incidents and production measurement errors.

In addition to using these diagnostic tools to detect separator problems, it is important to take advantage of diagnostics that ensure the health of the flowmeter itself. Diagnostic tools are available to verify the health of the flow sensor and transmitter *in situ* without the need to remove the flowmeter from the line. This is a powerful tool that can help eliminate the meter as the source of the measurement error while troubleshooting the process.

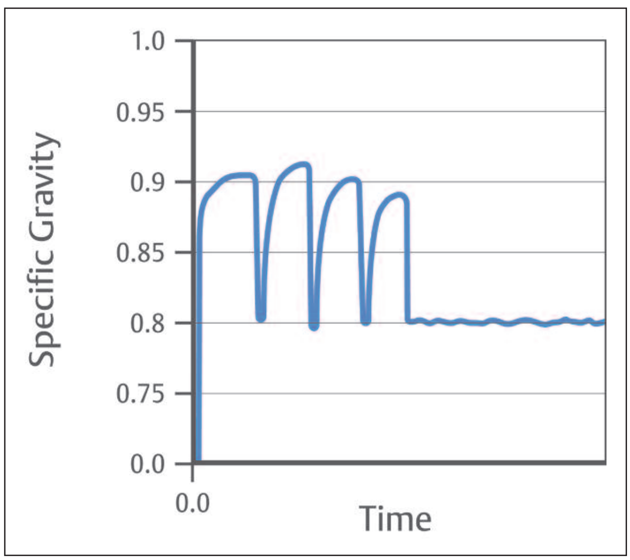


FIGURE 2. Flowmeter diagnostics also can measure density to help detect oil/water contamination in the oil or water leg. (Source: Emerson)

Implement reliable pressure control. Pressure control at the separator is required to ensure the optimal amount of light ends are either released to the gas leg or stabilized in liquid form.

If the separator operating pressure is too high, too many light components will stay in the liquid phase at the separator and will later release as gas in the tank, resulting in production loss due to venting or flaring. A high operating pressure also can increase backpressure on the well and decrease production. If the pressure is too low, fewer intermediate hydrocarbon components will remain in the liquid, resulting in a decrease in the quality and volume of the produced crude oil.

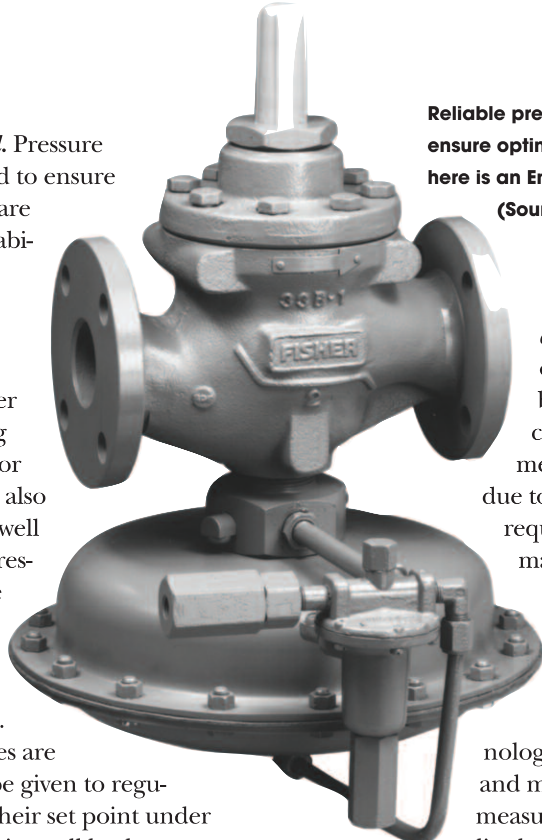
Not all pressure regulator devices are equal, and consideration should be given to regulators that more tightly maintain their set point under highly variable flow rates to minimize well backpressure and ensure higher crude stabilization.

In addition to pressure control, pressure relief valves or rupture disks are required per ASME pressure vessel code to protect against dangerous vessel over-pressurization. Using a relief valve with a position monitor or acoustic sensor provides an alert if the valve opens that can help in estimating vented gas volumes, ensuring safety and reducing emissions-related costs.

Connect reliability with remote automation solutions and innovative software. Having diagnostic information capability in the devices is a start, but the real power for improvement comes from the ability to automate and operate remotely.

Bringing all the device information into a RTU/SCADA system allows operators to gain better insight to separator and heater treater operations (Figure 3). Configurable systems that do not require complex programming and are designed to easily interface with field devices provide reduced startup time and ensure easy access to diagnostics. Simple cause-and-effect programming logic can be used to detect upsets and send alarms to allow scarce resources to go where they are needed the most.

Using well test management software to automate well testing allows for reduced well test cycle times and reduced risk of well test error due to manual operations. Accessing all of this information to remotely control and supervise assets enables significant improvements in operational efficiency.



Reliable pressure control at the separator is vital to ensure optimal measurement performance. Shown here is an Emerson Fisher brand pressure regulator. (Source: Emerson)

Use fit-for-purpose flow measurement devices. As there are many flowmeters on the market today, selecting the best technology for the application can be a challenge. Traditionally mechanical devices have been used due to their low cost and low power requirements. However, due to high maintenance costs, flow measurement errors and lack of diagnostic insight, these technologies are being displaced by more reliable meters that have no moving parts. Many operators are adopting technology such as Coriolis, ultrasonic, vortex and magnetic flowmeters for separator measurements. Each has advantages and disadvantages that should be evaluated based on the specific application requirements. Consultation with suppliers that offer a broad portfolio of measurement technologies will facilitate selecting the best meters that will provide diagnostic insights into how to improve separator and heater treater performance while minimizing total cost of ownership.

Implementing these separator and heater treater best practices will result in accurate and timely production data to enable reduced uncertainty in critical production management decisions and drive well optimization, reservoir life and long-term profitability. E&P

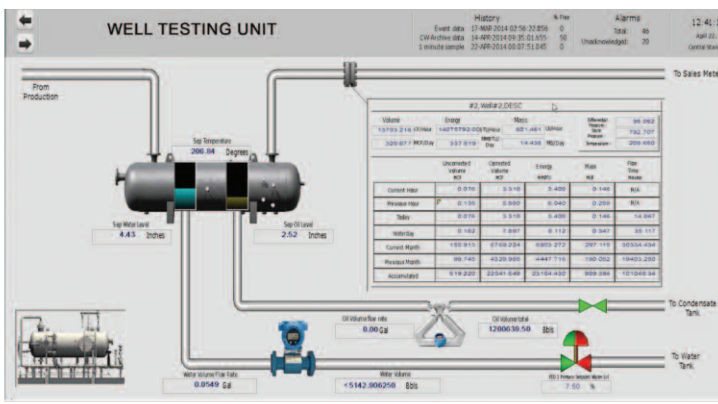


FIGURE 3. The ability to automate and remotely operate a well testing unit with all the diagnostic data available enables significant improvements in operational efficiency. (Source: Emerson)