A Method for Identifying and Reducing Errors in Wet Gas Measurement with Coriolis Meters

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1 Introduction

Effective reservoir management over the life of a field demands regular measurement of individual producers and injectors. However, the capital cost to enable continuous, high-accuracy measurement is difficult to justify for many assets, and often, measurement is facilitated through permanent or mobile test separation units that provide a snapshot of production character once a month or even less frequently. Whether in its initial production or late in life, a single well's production could change suddenly or dramatically, leaving production engineers scrambling through scarce data to find the culprit well and identify an action plan to return asset production to target rate and/or specification. These searches for the source of a water breakthrough or a failed downhole completion can be tedious and cost up to months of production as data is examined and well tests trickle in. To an increasing degree, operators are driven to consider direct wellhead measurement options to ensure optimal recovery and quick response to individual well production issues.

2 Direct wellhead measurement

As attractive as true multiphase meter measurement can be, multiphase meters typically represent a significant investment for the average asset in both initial spending and in maintenance (particularly for nuclear based devices). To date, the adoption rate of multiphase measurement has been significantly higher for subsea applications thanks to the greater initial investment and expected rate of return. Alternate methods to capture this measurement have included partial separation skids in which a gas-liquid separation is employed on a skid-basis allowing inherently single phase devices to more accurately gauge gas and liquid rates. Oil and water are then often differentiated either via a density-based net oil calculation when possible or use of a water-cut probe. While partial separation skids can offer reasonable accuracy, these meters often have a narrow operating range and represent a significant footprint and investment.

In an effort to gain insight into well performance without the investment in multiphase meters or partial separation skids, some operators have turned to inherently single phase technologies, such as Coriolis meters, for multiphase measurement with mixed success. Proper examination of well production characteristics and expected changes over the life of the asset can greatly increase the success rate of Coriolis technology in this application.

3 Coriolis measurement in multiphase flow

Coriolis meters are, like most other flow measurement technologies, designed to measure single-phase processes. Coriolis technology is unique in that it measures the mass flow and density of the process fluid simultaneously. If there are only two phases that need to be independently measured in a process (i.e. liquid and gas) and the densities at process conditions of the two phases are known, this would be enough information to provide an overall mass flow rate along with phase fraction. However, when multiple phases are present, some of the basic assumptions made in Coriolis measurement break down. Primarily, the fluid no longer vibrates in sync with the flow tubes, resulting in measurement errors. This section focuses on the two primary error sources in multiphase Coriolis measurement: decoupling and velocity of sound, or compressibility effects. These errors and their sources are only briefly discussed in this paper; additional discussion can be found in Weinstein [2]. The decoupling examples in this paper and cited references focus on liquid-continuous flow regimes. Although more study is needed in gas-continuous flow regimes, there no indication in studies to date that suggest that decoupling is substantially different in gas-continuous processes.

3.1 Decoupling effects

During Coriolis sensor operation, if a single-phase gas or liquid moves in the transverse direction exactly with the flow tubes, the center of gravity of the fluid remains fixed in the middle of the tube. However, the presence of two phases with different densities causes a decoupling of the transverse fluid motion from the tube motion. This causes mass and density measurement errors due to changes in the location of the center of gravity of the fluid mixture inside the tube. The term "decoupling" refers to relative motion between two components of differing density in the direction of tube oscillation, which is perpendicular to the direction of bulk fluid flow, as shown in Figure 1
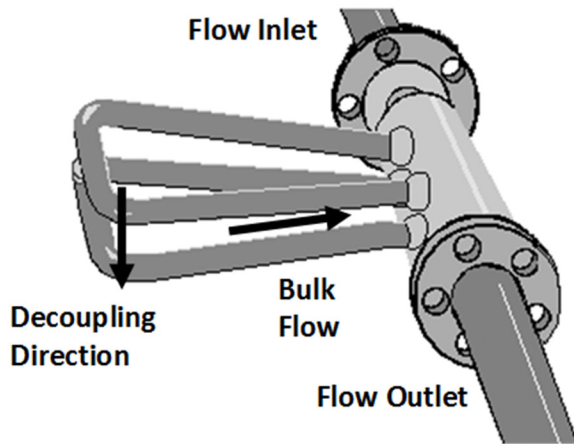
Figure 1: Direction of decoupling and bulk flow

Figure 2 shows a cross-sectional view of a single vibrating tube at two instances during a vibration cycle. At the point of maximum deflection, the bubble has moved further than the liquid, by a factor defined as the decoupling ratio: A_p/A_f. The amplitudes are defined with respect to the distance from the midpoint of tube oscillation. In the example of a sand particle, where the density of the particle is greater than that of the fluid, the particle would move less than the fluid, also imparting decoupling.
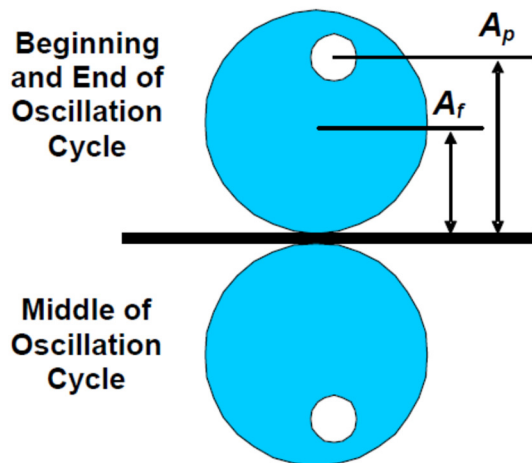

Figure 2: Decoupling ratio definition

Decoupling causes some of the liquid mass in the tubes to move so that it is undetected by the flow meter. This causes the density to read lower than the mixture density in the case of a bubbly fluid. For example, if a mixture consists of 10% volume fraction gas in a liquid of density 1000 kg/m^3, then the meter

density should read 10% lower than the liquid, or 900 kg/m^3, assuming the gas density is negligible. However, due to decoupling, the meter erroneously measures perhaps 898 kg/m^3. The further the bubbles or particles decouple from the fluid on each oscillation of the tubes (i.e. greater A_p/A_f), the larger the undetected mass of fluid will be and the larger the resulting density error.

Mass flow is also affected by decoupling. Mass flow errors are the result of asymmetric damping and mass between the two sides of the meter caused by two-phase conditions. Depending on the orientation of the meter, this error can be either positive or negative. For example, if a meter is installed tubes down, then because of gravity, more gas will be trapped on the inlet side of the meter, Figure 3. This will result in more mass on the outlet side of the meter, and increased damping, due to decoupling effects, on the inlet side of the meter. Both of these effects will result in mass flow error.
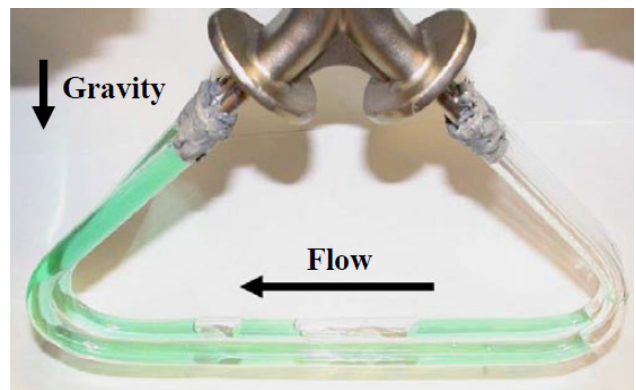

Figure 3: Asymmetric phase distribution

It may be intuitively unclear why a bubble moves further than the bulk fluid on each oscillation of the flow tube. To understand this, consider the simple case of a bubble flowing with a fluid inside a pipe. Relative movement of the gas phase in pipe flow is typically known as the slip velocity and is a measure of how fast the gas phase moves with respect to the liquid phase. This is similar to the case of decoupling in oscillatory motion, except that the acceleration is caused by a pressure gradient, instead of tube motion.

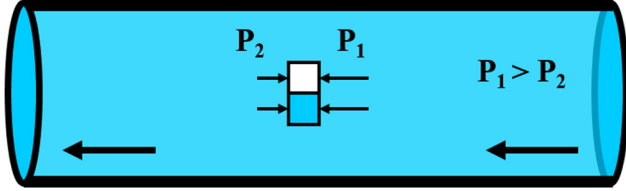Consider two equally sized cubes of fluid flowing through a pipe as shown in

Figure 4.   The first cube is an air pocket and the second is a fluid of the same density as the surrounding fluid. The same pressure force is exerted on the upstream and downstream faces of both cubes, and all pressure forces exerted on faces in the direction perpendicular to flow cancel out. Therefore, with the same pressure force exerted over the same area, each cube will experience the same net pressure force in the downstream direction. Bubble slip occurs because the gas cube is less dense than the liquid cube and Newton's law requires that, under the same force, the lighter gas cube must have higher acceleration.
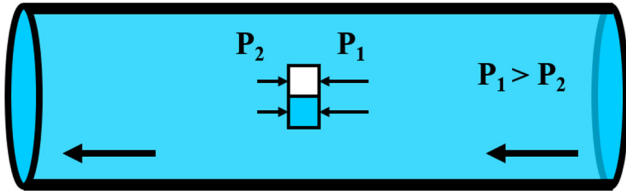

Figure 4: Bubble slip velocity in pipe flow

To better understand where decoupling errors come from and how to better mitigate them, the density ratio and inverse Stokes number are considered. The inverse Stokes number and density ratio are non-dimensional numbers used in the equation that describes oscillatory motion of a spherical particle in a viscous fluid. The density ratio is the ratio of fluid and particle densities, equation 1, where ρ_f represents the fluid or liquid phase, and ρ_p represents the particle or gas phase. The density ratio indicates the importance of the inertial difference between the phases which is the driving force for decoupled motion.   The inverse stokes number, equation 2, represents the viscous effects of the fluid where, ν_f is the kinematic viscosity of the fluid, ω is the frequency of the fluid oscillation or the drive frequency of the flow meter, and a^2 is the radius of the particle, liquid droplet, or gas bubble.

$$Density\ Ratio = \frac{\rho_f}{\rho_p} \qquad 1$$

$$Inverse\ Stokes\ Number, \delta = \sqrt{\frac{2\nu_f}{\omega a^2}} \qquad 2$$

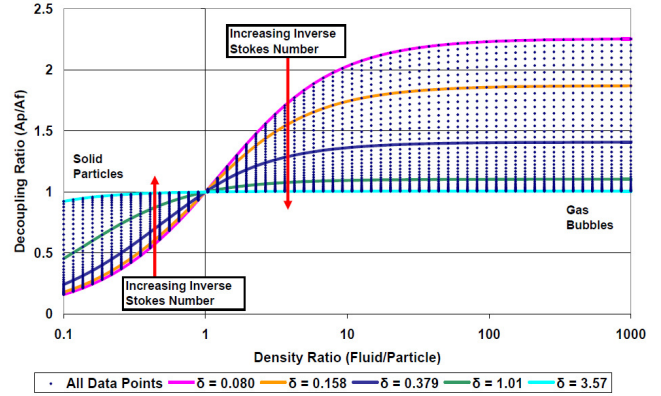Figure 5 below relates the decoupling ratio to the density ratio and inverse Stokes number.

Figure 5: Decoupling Ratio vs. Density Ratio vs. Inverse Stokes number

The inverse Stokes number, δ, shows that it is the balance between fluid kinematic viscosity, particle size, and frequency that is important, not any one of these variables alone. By increasing inverse stokes number the decoupling ratio can be significantly reduced, resulting in smaller mass and density errors. While viscosity is often not under a user's control, meter frequency and bubble or droplet size are. Equation 2 shows that low frequency Coriolis meters are less prone to decoupling errors and should be used in applications where two-phase conditions may be expected. Equation 2 also shows that because particle size is the only variable that is squared, small changes in bubble or droplet size overwhelm changes in viscosity or frequency. Increasing pipe pressure by adding a pump or increasing back pressure will decrease bubble size, and in liquid-continuous applications, may even force gas back into solution and return the process to single-phase. In gas-continuous processes, increasing the pressure may cause there to be more liquid condensate, causing higher measurement errors; in applications where an increase in pressure is unlikely to cause phase change, increasing pressure can reduce errors by reducing the difference in density of gas and liquid, which reduces decoupling.   Also, keeping pipe velocities high and using mixing devices can effectively decrease bubble or droplet size and dramatically improve measurement performance.

3.2 Decoupling error test results

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The examples below focus on liquid-continuous processes, but in the case of gas-continuous processes, the results are similar: increasing liquid content in the gas causes higher magnitude errors, and decreasing droplet size causes lower magnitude errors. Figure 6 shows percent mass flow error from true mixture mass flow in a Coriolis meter due to entrained gas. Pressure inside the meter is held constant at 210 kPa (30 psig) for all tests, while flow rate and the amount of gas injected are varied. For each test at constant mass flow rate, increased gas volume fraction results in increased measurement error. However, performance improves with increasing flow rate with as little as 1% error at 10% gas void fraction because the gas phase is broken down into very small bubbles rather than the larger slugs of gas which occur when pipeline velocities are low. As described by the inverse Stokes number, this results in a more homogenous fluid mixture with smaller bubbles that decouple from the fluid phase to a lesser extent.
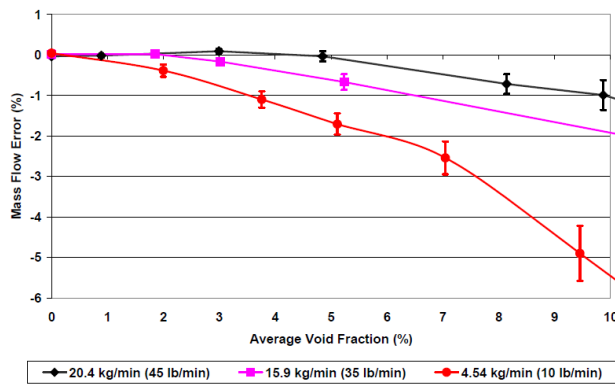

Figure 6: Mass flow error due to entrained gas

Density error from true mixture density is shown in Figure 7 for the same conditions. As expected, performance degrades with increasing void fraction and improves with increasing flow rate. Sizing and installation of a meter to minimize bubble impact can dramatically improve results.
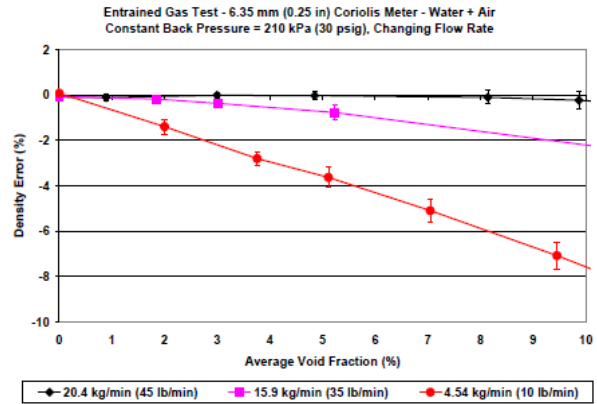

Figure 7: Density Error due to entrained gas

3.3 Velocity of sound effects

In addition to problems caused by the relative motion of bubbles, droplets, and particles, Coriolis meters experience velocity of sound effects when the sonic velocity of the measurement fluid is low or the oscillation frequency of the meter is high. Gases have lower sonic velocities than liquids, but the lowest velocities result from a mixture of the two. The addition of even a small amount of gas to a liquid results in a dramatic reduction in the velocity of sound of the mixture below that of either phase.

The oscillation of the flow tube produces sound waves that oscillate in the transverse direction at the drive frequency of the meter. When the velocity of sound of the fluid is high, as in a single-phase fluid, the first acoustic mode for transverse sound waves across the circular conduit is at a much higher frequency than the drive frequency. However, when the velocity of sound drops due to two-phase conditions, the frequency of the acoustic mode also drops. When the frequency of the acoustic mode and the drive mode are close, meter errors result due to the off-resonance excitation of the acoustic mode by the drive mode. For low frequency meters and typical process pressures, velocity of sound effects are negligible with respect to the specified accuracy of the meter. However, for high frequency Coriolis meters, the velocity of sound can be low enough to cause significant measurement errors due to interaction between the drive and fluid vibration modes.

A more physical explanation of velocity of sound effects in Coriolis meters is that the fluid in the tube is compressed against the outside wall of the tube on

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each oscillation when the compressibility of the mixture is high enough to allow for such motion. In this way, velocity of sound effects are similar to decoupling effects in that the actual error is caused by movement of the location of the center of gravity. The difference is that velocity of sound effects result in heavier fluid pushed to the outside walls of the tube while decoupling results in heavier fluid pushed to the inside walls of the tube. For this reason, velocity of sound errors are positive and decoupling errors are negative.

This is confirmed by a recent model by Hemp & Kutin [1], which quantifies density and mass flow errors due to velocity of sound effects. The closed form expressions are given as percentage increases from true mixture values, where d is the inner diameter of the Coriolis meter flow tube, ω is the angular oscillation frequency, and c_m is the mixture velocity of sound.

$$\rho_{vos,err} = \frac{1}{4}\left(\frac{\omega d}{2c_m}\right)^2 * 100 \qquad 3$$

$$\dot{m}_{vos,err} = \frac{1}{2}\left(\frac{\omega d}{2c_m}\right)^2 * 100 \qquad 4$$

4 Improving Coriolis capabilities

Performance of Coriolis meters in two-phase flow is not necessarily limited by the errors discussed in section 3. Correction techniques can be applied to improve their performance in limited two-phase applications. The first step in remediating gas measurement errors in two-phase conditions is identifying when single-phase and two-phase conditions occur within the sensor. Additionally, diagnostic and trending information can be derived from the meter to help customers better understand their application.

4.1 Enhanced liquid volume flow measurement

The performance of Coriolis meters can be greatly improved by using drive power or drive gain to detect when there is single or two phase flow in the meter. Drive gain is proportional to the power used to vibrate the meter's flow tubes. In two phase flow, much of the energy used to drive to flow tubes goes into the relative motion between the liquid and gas phases, requiring an increase in drive power to maintain constant tube amplitude. Sharp increases in drive gain are indicative of two phase flow. Due to limited available power because of intrinsically safe limits, drive gain quickly reaches 100% with small amounts of gas, at which point tube amplitude begins to drop.

For most oil and gas applications, gas is not always present in the meter. For example, on the liquid end of a separator the fluid is primarily single phase. However, if the separator is not tuned properly, gas may occasionally be pulled through the liquid leg at the end of a dump cycle. Generally, for applications with little gas, liquid volume flow rate is desired. In the presence of gas, there is usually positive error on the liquid volume flow rate because Coriolis meters measure the mixture, both gas and liquid, properties of the process fluid. To better understand how mixture measurements relate to liquid measurements and how to better approximate liquid quantities, the errors due to entrained gas on mass and density, from which volume flow rate is derived, are considered. Recall, volume flow rate is calculated using mass and density, equation 5.

$$\dot{V} = \frac{\dot{M}}{\rho} \qquad 5$$

Where $\dot{V}$ is the volume flow rate, $\dot{M}$ is the mass flow rate, and ρ is density. Conveniently, the mixture mass flow rate closely approximates liquid mass flow rate due to the small contribution from the gas phase. This is because the density of gas is much smaller than the density of the liquid.

$$\dot{M}_{mixture} = \dot{M}_{liquid} + \dot{M}_{gas}$$

$$\dot{M}_{gas} \ll \dot{M}_{liquid}$$

$$\dot{M}_{mixture} \sim \dot{M}_{liquid} \qquad 6$$

At high fluid velocities and for low frequency meters, error on the mixture mass flow rate is small (see Figure 6); thus, the error on the measured liquid mass flow rate is small. Conversely, mixture density does not closely approximate the liquid density. This is shown in equation 7.

$$\rho_{mixture} = \rho_{liquid} * \varphi_{liquid} + \rho_{gas} * \varphi_{gas}$$

$$\rho_{mixture} \neq \rho_{liquid} \qquad 7$$

Where φ_{liquid} and φ_{gas} are the liquid and gas void fractions respectively. Equation 5 shows that small amounts of gas can have a large impact on the mixture density. For example, consider a mixture of 95% water, $\rho \sim 1$ g/cc, and 5% air at atmospheric pressure, $\rho_{air} \sim 0.0$ g/cc. The mixture density is .95 which is 5% lower than the liquid density. Again, this does not take into account decoupling and velocity of sound errors discussed in section three, but similar to mass flow, these errors are can be kept small when the GVF and meter frequency is low, and velocity is kept high. Because mixture density is lower than the liquid density, the mixture volume flow rate output from a Coriolis meter is higher than the liquid volume flow rate. To closer approximate the liquid volume flow rate, density from a period no entrained gas can be held and used during a period when there is entrained gas. Periods of gas and no gas are defined

using drive gain and a drive gain threshold. The drive gain threshold is tuned such that when drive gain is above it, there is gas in the meter. See Figure 8 below.
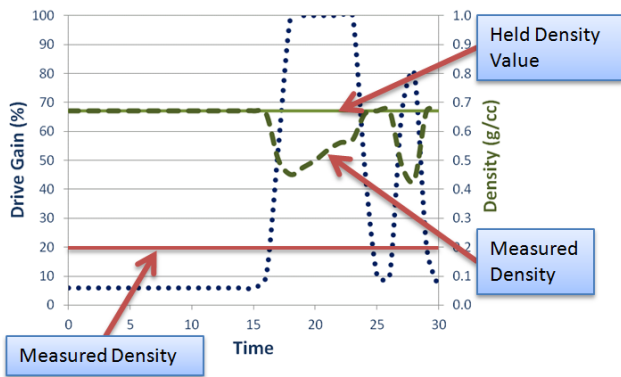

Figure 8: Hold Liquid Density Value

Once drive gain goes above the drive gain threshold, a density value from a period of no gas is used in place of the measured density. The output volume flow rate will now represent the liquid volume flow rate instead of the mixture volume flow rate, which is generally more relevant to the oil and gas applications. Using the above technique, the accuracy of the liquid volume flow rate depends heavily on the accuracy of the measured mass flow rate. As mentioned before, mass flow rate accuracy can be improved by ensuring flow velocities are high and a meter with low frequency is used. The above methods can be further enhanced if the user specifies oil and water densities. In this case, water-cut and net oil can be determined.

4.2 Improving gas measurement

Similar techniques to those used to detect entrained gas in a liquid process can be used to detect liquid mist in a gas process, with certain coriolis sensor designs. Testing at Southwest Research Institute [3] shows drive gain in coriolis meters with a large "U" shaped geometry are very sensitive to even small amounts of liquid.
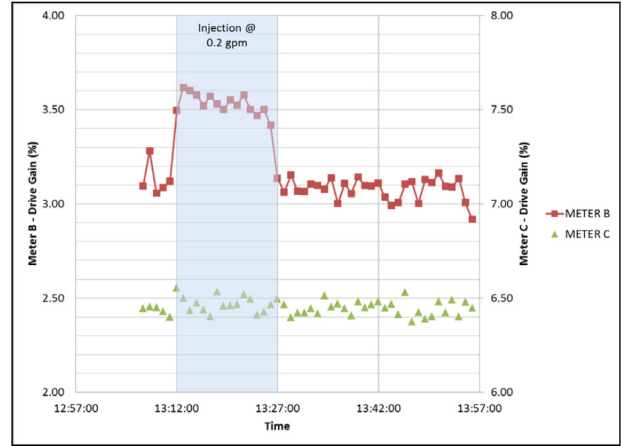

Figure 9: Drive gain response, 0.027% liquid

Figure 9 shows that with as little as 0.027% liquid by volume, drive gain is a clear and immediate indicator in one coriolis meter, but does not register with the other. Even with half as much liquid, drive gain is still useable as an indicator, although it is a fairly subtle change:
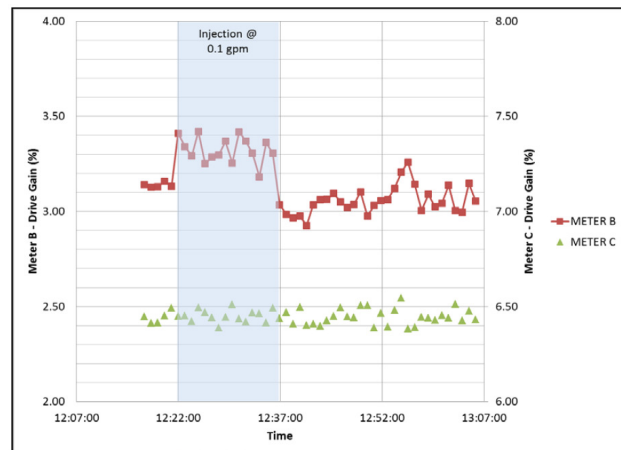

Figure 10: Drive gain response, 0.013% liquid

Once liquid is detected, an algorithm to the one outlined above for liquid processes can be used to remediate gas flow rate measurement. Equation 6 showed that it is very easy for the mass flow rate of liquid to overshadow the mass flow rate of gas:

$$\dot{M}_{mixture} = \dot{M}_{liquid} + \dot{M}_{gas}$$

$$\dot{M}_{gas} \ll \dot{M}_{liquid}$$

$$\dot{M}_{mixture} \sim \dot{M}_{liquid}$$

In a gas process, this is detrimental to the measurement, since the desired output is often <u>gas</u> volume at standard pressure and temperature, which is simply:

$$\dot{V}_s = \dot{m} \cdot \rho_s$$

where $\dot{V}_s$ is the volume rate flow at standard condition, $\dot{m}$ is the mass flow rate at line conditions, and ρ_s is the density of the gas at standard conditions. The standard density of the gas is constant, provided the gas composition doesn't change, so mass flow rate is the critical measurement for gas processes.

To avoid the large errors in gas mass flow measurement that would be incurred by measuring liquid as well (often called "over-read"), when two-phase conditions are detected by increases in drive gain, the mass flow rate from a few seconds before the two-phase conditions can be substituted for the bulk measurement, until the process returns to single phase gas. If the mass flow rate of the dry gas before and after the wet gas period is different, then a small adjustment can be made (see G in Figure 11) to the flow rate, so that the total will reflect a linear change in dry gas flow rate during the two-phase period, rather than a step change as the process transitions back to single-phase gas.
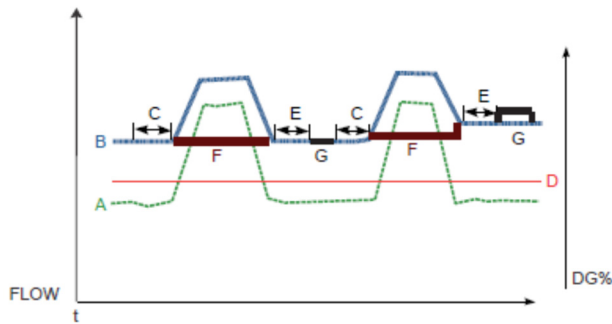

Figure 11: Gas remediation

In Figure 11, the letters represent the following:

A – Drive Gain
B – Bulk Mass Flow Rate
C – Pre-Mist averaging of flow rate
D – Drive Gain Threshold
E – Post-Mist Delay
F – Held Mass Flow Rate
G – Post-Mist Adjustment

4.3 Lab Testing of Remediation Algorithm

For the algorithm to work properly, the process should have a flow regime that has periods of single-phase gas and periods of two-phase or wet gas conditions. These conditions were created in the 4-inch wet gas test facility at Colorado Experiment Engineering Station, Inc (CEESI) by installing a liquid injection point directly upstream of the meter, so that the flow regime could quickly transition from dry to wet and back to dry. Test points consisted of a dry period, a two-phase test point and followed by another dry period. Data points represent a 2-minute average of the two-phase test point.
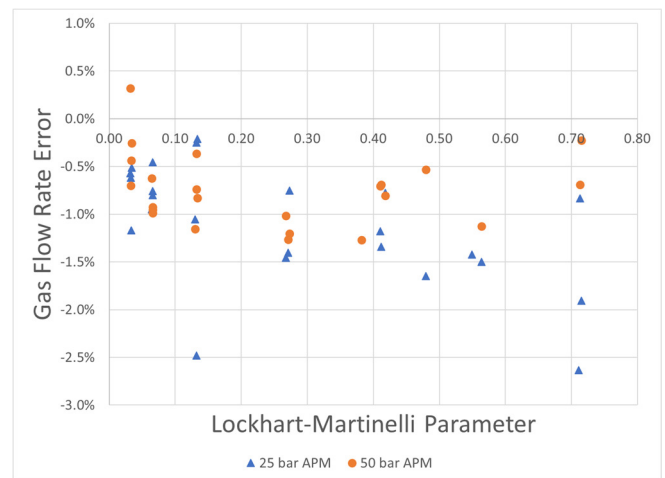

Figure 12: Gas measurement error vs X

The results are shown in Figure 12. Gas flow rate error falls largely between 0% and -2%, regardless of pressure. This contrasts quite starkly with the gas 'over-read' if the standard mass flow output is used. Since the algorithm detects and ignores liquid in the process, much of the 'over-read' can be avoided. Figure 13 shows the remediated gas-only measurement and the unremediated mixture flow rates at 25 and 50 bar (absolute). There is a difference in performance for the standard coriolis meter output which depends on the pressure of the process. This aligns with the decoupling model of errors in two-phase process, since the ratio is lower with more dense gas at higher pressure.

With the output form the algorithm, there is no need to characterize and correct for the errors at various phase fractions and pressures, which would rely on the addition of a pressure measurement and an estimation of phase fraction, which would create additional sources of error.
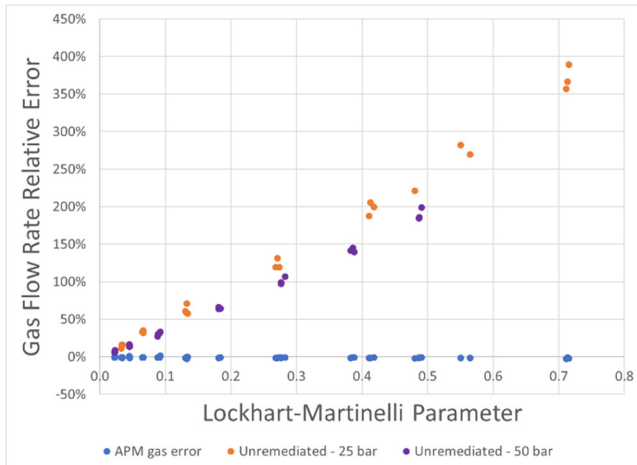
Figure 13: Gas 'over-read' vs X

4.4 Field Testing of Remediation Algorithm

Since the testing of the algorithm in the lab was under conditions that were known to be conducive to the algorithm, field testing was essential to proving that the algorithm is viable in real-world process conditions. The key attribute is slugging, or other forms of transitions from dry to two-phase conditions. The application chosen to test a gas well on plunger lift, since the plunger will deliver the liquids all at once, giving the line time to dry out between plunger arrivals. The arrival of the plunger, and the behavior of the unremediated mass flow rate and algorithm remediated gas mass flow rate can be seen below in Figure 14.
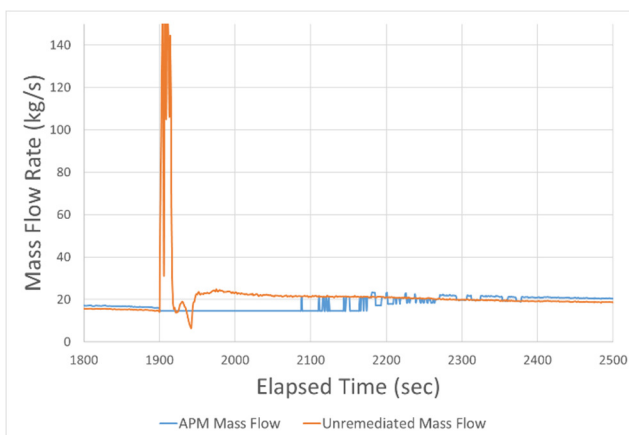

Figure 14: Plunger lift mass flow rate

In this field test, a coriolis meter was mounted directly off the wellhead and there was a gas-liquid separator with orifice plate flow measurement on the gas outlet as a gas flow rate reference. The remediated gas flow measurement from the coriolis meter agreed with the gas reference within ±1.5%.

Other field data has been captured that shows liquid slugging on naturally producing wells that would also be conducive to the algorithm. No reference measurement was available, but this shows that intermittent dry gas conditions do exists commonly in real-world applications.

4.5 Installation Effect on Wet Gas

Wet gas applications are also much more susceptible to installation effects than dry gas.

Using drive gain/power to differentiate between periods of low measurement uncertainty and high uncertainty can also grant insight into problems with other parts of the process. An example is a tank vent where there is expected to be occasional wet gas with a drip pot installed to catch any liquid before it enters the meter. If installed incorrectly and not emptied on a regular basis, water vapor and other liquids may be passed through the meter on a continuous basis, where there is potential for any water vapor to freeze. Due to the relatively high mass flow rate of any liquids, this will also cause large errors in gas volume flow measurement.
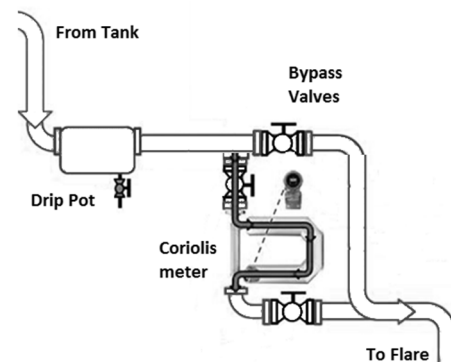

Figure 15: Example of proper installation for wet gas application

Figure 12 illustrates an example of proper wet gas installation, with the drip pot above the level of the meter inlet and flow downwards though the meter.

4.6 Diagnostics and Trending

In addition to improving Coriolis meter accuracy, diagnostic information can be derived from the meter to give the user more insight into their process. Examples of this include percent time that two-phase conditions, or alerts can be created for sharp changes in any of the process variables, sudden onset of liquid in a typically dry gas well, or charges in flow regime.

Data trending can be used to further improve the value of Coriolis meters in wet gas applications. Two-phase conditions impose a lot of noise on any of the

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output variables. This is true even when the amount of liquid is quite small and accuracy is still high. By averaging data, and only periodically outputting each averaged variable the noise can be reduced allowing users to better understand the trends of their process and avoid having slower polling SCADA systems, or other data loggers from recording an outlier. Figure 16 shows data taken from a three-inch Coriolis meter directly mounted to a wellhead. The average gas void fraction is roughly 3 – 4%, and the flow accuracy of the meter is +/- 5%.
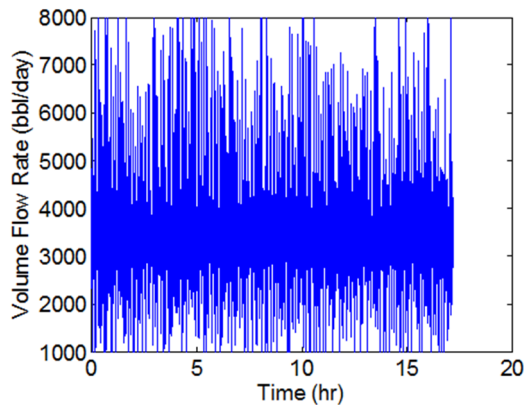

Figure 16: Noise due to phase conditions

Despite the relatively low amount of liquid and high accuracy, the volume flow rate when sampled once a second is very noisy. The noise is due mostly to occasional large slugs of gas, while on average there is limited gas. This noise makes determining trends in the data very difficult. Just by averaging the data and periodically outputting the average it is much easier to identify any trends in well performance. Utilizing additional insight into the sources of error in Coriolis measurement in two-phase conditions and leveraging methods mentioned above, this data can be further improved upon to yield more accurate totals and trends.
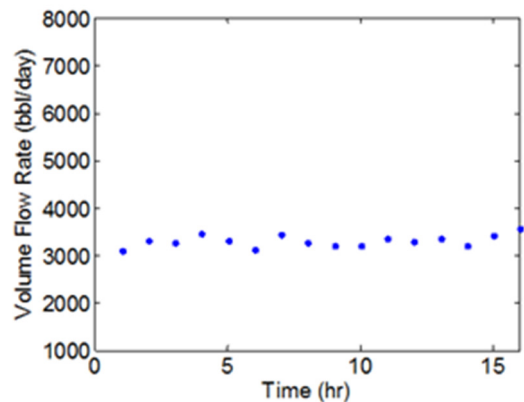

Figure 17: Trending with averaged data

5   Conclusion

Two-phase in general, and wet gas or gas-continuous processes always present challenges relative to single-phase flow measurement applications. When evaluating the capabilities of any measurement technologies in these challenging applications, it is critical to fully understand the needs of the user and what information from the meter is of real value to the user for that application. For customer that have gas-continuous processes where it is valuable to detect the presence of liquids and/or provide a gas-only flow measurement, even when the process contains some liquids, this algorithm presents a robust solution that has the added benefit of all the diagnostics and additional measurements that a coriolis meter can provide. It is important to consider the flow regime of the process, but the field test to date have shown that many processes have sufficient slugging to provide the algorithm with the good dry gas reference conditions and steady flow conditions that are conducive to the algorithm's performance.

6   References

[1]   J. HEMP AND J. KUTIN. 2006. Theory of errors in Coriolis flowmeter readings due to compressibility of the fluid being metered. *Flow Measurement and Instrumentation*. 17:359-369.

[2]   J.A. WEINSTEIN. 2008. The motion of bubbles and particles in oscillating liquids with applications to multiphase flow in Coriolis meters. *University of Colorado at Boulder Dissertation*. Proquest: AAT 3315790.

[3]   A. HAWLEY AND J. THORSON. 2015. Turbine and Coriolis Meter Diagnostics with Entrained Liquids. Pipeline Research Council International. PR-015-14603-R02