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August 2008 Vol. XIV, No. 8 • *www.FlowControlNetwork.com*
GRAND VIEW MEDIA GROUP

by Raymond J. Kalivoda

Flowmeter Application Considerations

Knowing the Limits of Ultrasonics for Crude Oil Measurement

Liquid ultrasonic flowmeters are gaining acceptance in the petroleum industry for a wide range of applications. Initially they were used for non-custody scenarios, but with advances in microprocessors, transducers and electronic technology, multipath ultrasonic flowmeters are now being used to provide highly accurate custody-transfer flow measurement. As such, ultrasonic flow measurement technology has been recognized in many European countries, and API Standard 5.8, *Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters Using Transit Time Technology*, recognizes such technology in North America.

High accuracy and low maintenance are the key advantages of ultrasonic flowmeters. But these meters, like turbine-based devices, arrive at a measurement by inference, i.e., they infer the volumetric throughput by measuring the velocity over the flow area. As with all velocity meters, ultrasonic flowmeters are Reynolds Number dependent, which is to say they are more or less affected by the relationship between velocity and viscosity. They may also be affected by entrained solids, water, gas, and wax. All of these characteristics can influence both the short-term accuracy and long-term stability of an ultrasonic meter.

Ultrasonic Flowmeters for Crude Oil

Crude oil measurement, unlike refined products, defines a wide range of applications from light condensates with a viscosity of less than 0.5 cP to heavy crude oils over 2,000 cP. The level of contaminants present in crude oil applications also varies widely.

Viscosity can be expressed in many different units, but for the purposes of this article, kinematic viscosity, which is expressed in centistokes (cSt), is most suitable. The other commonly used viscosity units in the petroleum industry are dynamic viscosity, centipoise (cP) — which can be converted to centistokes by dividing by the specific gravity, (cSt = cP / SG) — and Saybolt Seconds Universal (SSU) viscosity — which can be changed to centistokes with a conversion chart.

Crude oils are normally defined by their API gravity, which is sometimes confused with the product's viscosity. API gravity is defined as the density of crude oil at a specific temperature compared to the density of water at a standard temperature of 60 F. The relationship between specific gravity (SG) and API gravity is:

SG (60 F/60 F) = 141.5 / (131.5 + API)

API gravity is loosely related to viscosity. For light crude oils, there is a fairly close relation between viscosity and API gravity. For medium and heavy crude oils, it is important to obtain the viscosity from the assay or from a specific viscosity test.

The viscosity of all liquids varies with temperature as Table 1 illustrates. The effect of temperature for medium and heavy crude oils can significantly change a meter's performance due to the considerable change in viscosity. For this reason, it is important when evaluating any meter application that the viscosity of each product must be specified over the operating temperature range.

Fluid Properties

Sediment & water (S&W) is a collective term for non-hydrocarbons found in crude oil. In API MPMS Chapter 1, S&W is defined as: "A material coexisting with, yet foreign to, a petroleum liquid; may include free water and sediment (FW&S) and emulsified or suspended water and sediment (SW&S)."

Since all pipelines regulate the amount of S&W they will accept — normally less than 1 percent — a crude oil within these requirements is termed "pipeline quality oil." In general, the free water in pipeline quality oil should not be a problem for measurement with ultrasonic meters. Sediment though, especially small particulates, may be a problem because it can diffuse the ultrasonic signal.

Gas slugs or entrained gas will not damage an ultrasonic meter, but they can adversely affect measurement accuracy. Even a small number of gas bubbles can cause attenuation of the ultrasonic signal. The degree of attenuation depends on a number of factors, such as pressure, bubble size, amount of free gas, temperature and signal frequency.

Wax crystals begin to form in a petroleum product at a specific temperature known as the cloud point. If a meter is operated below the cloud point, wax can form on the measurement element, which can notably affect the meter's accuracy. Some meters are considerably more tolerant of waxing than other meters. For example, after an initial buildup of wax on the walls of one positive-displacement meter, rotating blades wipe the surfaces, and the meter factor remains stable. In the case of velocity meters (e.g., ultrasonic and turbine) there is a continuous meter factor shift as the wax builds up.

Principle of Operation

The operating principle of ultrasonic meters is shown in Figure 1. The volume throughput (Q) is equal to the fluid velocity measured (Vm) times the area (A) or Q = Vm x A, where the fluid velocity measured is proportional to the difference between an ultrasonic signal traveling with the flow (t_{AB}) and against the flow (t_{BA}). The measurement principle is fairly simple, but there are a number of factors that must be addressed to achieve the accuracy necessary for custody-transfer measurement. Some believe ultrasonic meters are not sensitive to fluid properties — this is not the case. To achieve the level of precision measurement available with other metering technologies, effects such as S&W, gas slugs and wax crystals need to be addressed. This is particularly important with crude oil applications, as these measurements are often highly viscous with high levels of contaminants.

Table 1. *Effect of temperature on the viscosity of selected products.*

API gravity for selective crude oils	Viscosity in cP @ deg F (deg C)		
	60 (15)	100 (38)	150 (66)
48 API	2.7	1.7	1.1
32.6 API	21	9	5
25.3 API	1442	243	93
17.8 API	2040*	340	130*
16.2 API	3440*	574	230*
10 API	5100*	1294	520*

*estimated

Influence of Fluid Properties on Performance

On a qualitative level, the influences of fluid properties on ultrasonic flow measurement systems have been addressed by various researchers. On the other hand, knowledge on the quantitative effects of fluid properties on ultrasonic meter accuracy is limited.

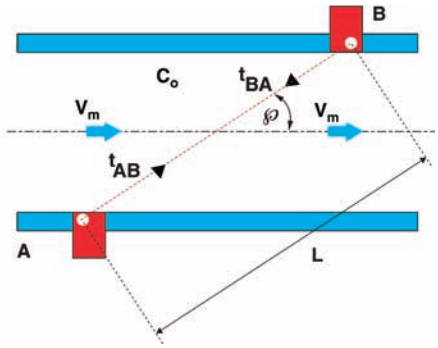

Figure 1. Operating principle of liquid ultrasonic flowmeters

The influence of fluid properties on ultrasonic flowmeter performance can be classified into two main groups:

(a) Signal quality effects – The signal attenuation and signal-to-noise ratio (SNR) in the acoustic paths.

(b) Flow profile effects – The robustness of the integration method used to combine the individual acoustic path measurements into a full volumetric flowrate measurement.

The signal quality of an ultrasonic meter in crude oil applications is determined by viscosity, entrained gas, sediment & water (S&W) and wax content. The signal strength, or more precisely, the signal-to-noise ratio (SNR), is crucial for the accuracy of the transit-time measurements made in the liquid ultrasonic flowmeter. Reduced SNR can mean higher uncertainty of the transit-time measurement, and thereby higher uncertainty of the volumetric flowrate measurement. In the worst case, the signal can't be discerned from the noise and the measured output is erroneous.

Noise is classified as:

- **Coherent noise** (signal interference)

a. Transducer "ringing" effects
b. Spool-piece borne signals (acoustic cross talk)
c. Liquid-borne reflections (transducer ports reflections, pipe wall refletions/reverberation).

- **Incoherent noise** (signals with random phase relative to measurement signal):

a. Electromagnetic noise (RFI)
b. Flow noise
c. Valve noise
d. Structural (pipe) vibrations, etc.

The strength (amplitude) of the measurement signal has to compete with noise to give a sufficient SNR. A number of fluid-dependent factors can attenuate the measurement signal and decrease the SNR. The factors that contribute to the sound attenuation coefficient, α, are:

$$\alpha = \alpha_{abs} + \alpha_{wio} + \alpha_{gas} + \alpha_{solids} + \alpha_{wax},$$

Where:

- α_{abs} is the sound absorption coefficient of the pure fluid; and
- α_{wio}, α_{gas}, α_{solids}, and α_{wax}, account for contaminants in the crude oil that cause excess attenuation due to entrained water, gas, solid particles and wax at the transducers.

Sound absorption (α_{abs}) is the attenuation due to viscosity and the influence of absorption on the SNR. Table 2 shows the absorption coefficient α_{abs} in terms of attenuation/distance between transducers. The absorption increases with viscosity and the distance between transducers, therefore the larger the meter diameter the higher the absorption.

***Table 2.** Sound absorption coefficient for water and oil samples**

Sample	Specific Gravitiy	Sound Velocity [ft/s]	Viscosity [cSt]	α_{abs} @ 1 MHz [dB/in]
Water (distilled)	1.00	4.856	-	
"Light Oil"	0.81	4,420	4	0.11
"Medium Oil"	0.85	4,598	14	0.18
"Brad Penn"	0.86	4,666	20	0.10
"Heavy Oil"	0.87	4,729	55	0.23
"Extra Heavy Oil"	0.88	4,856	337	1.14

* Data at 70 F

Water droplets (α_{wio}) in the oil cause excess sound attenuation due to scattering of the sound waves by the droplets. The effect on the SNR is accounted for in the attenuation coefficient α_{wio}. The coefficient is determined by the water droplet size and distribution, the amount of water in the oil, the pressure and temperature, the oil type and the ultrasonic flowmeter signal frequency. Because of the complexity of this relationship, it is difficult to determine the attenuation coefficient with a high degree of certainty. In the development phase of one recently introduced liquid ultrasonic meter, extensive testing was done on water-in-oil effects on signal attenuation. The following is a summary of these tests:

- The ultrasonic meter may operate with up to 5 percent water-in-oil, depending on the size of the water droplets.
- The influence of pressure on water-in-oil absorption is minimal, as expected due to the low compressibility of the fluids.
- Temperature can heighten or lower the attenuation, depending on other factors.

Free gas-in-oil (α_{gas}), in the form of gas bubbles, causes excess sound attenuation due to scattering of the sound waves by the bubbles and bubble resonances. The parameters that affect this coefficient are bubble size and distribution, the amount of free gas present in the oil, the pressure and temperature, the oil type and the ultrasonic flowmeter's operating frequency. Gas-in oil is a highly complex condition that can have a profound effect on performance. As found in the development of the liquid ultrasonic meter cited above, even small amounts of entrained gas can adversely affect ultrasonic meter performance. A summary of the gas-in-oil effects on signal attenuation states:

- For small bubbles (less than 0.5 mm diameter) a concentration as low as 1,000 PPM (0.1 percent) can momentarily or completely interrupt the measurement signal.
- For bubbles over 0.5 mm diameter, a concentration up to 10,000 PPM (1 percent) may be tolerable before the SNR is reduced to a critical level.
- The attenuation is based on path length, so the larger diameter meters are proportionately more affected by entrained gas than smaller diameter meters.
- Low pressure can significantly increase the signal attention.
- Temperature has minimal affect.

Solid particles-in-oil (α_{solids}), like free gas-in-oil can cause excess sound attenuation due to scattering of the sound waves by the particles. The same parameters that affect free gas-in-oil also affect the α_{solids} coefficient. The effect of solid particles-in-oil has not been studied in detail. Cursory testing shows results similar to gas-in-oil.

Wax can affect the SNR and the meter's K-factor. If the temperature is below the cloud point, wax contamination may build up on different surfaces of the ultrasonic flowmeter. Possible influences that may be important for the ultrasonic flowmeter's performance include the following.

Wax layer buildup:

- **At the transducer fronts** may shift the transit times and cause a continuous meter factor shift as the wax builds up. Cause attenuation (α_{was}) can reduce the SNR. Due to the relatively small difference in the acoustic impedance between oil and wax, a thin wax layer may not affect the SNR significantly, unless the layer gets thick and not homogeneous.

- **In the transducer cavities** may reduce the acoustic isolation of the transducer from the spool piece and increased acoustic "cross-talk" through the spool piece. Since cross-talk acts as coherent noise, this results in reduced SNR, and thus can reduce accuracy of the transit-time measurements.
- **On the inner wall surface of the spool piece** reduces the flow area, which increases the meter's K-factor. Since flow area A is equal to the pipe radius squared ($A=\pi R^2$), even a relatively small buildup can cause a large measurement error. For example, a 0.1 mm buildup on the interior diameter of a six-inch meter will result in a 0.27 percent measurement error. For a 20-inch meter, the error is proportionally smaller, about 0.08 percent. Regular in-situ proving of the flowmeter will correct for misreading due to such wax buildup.

Proving Recommendations

In-situ proving at regular intervals is recommended to maintain optimum measurement accuracy. Ultrasonic meters, as previously stated, are like turbine meters in that they infer the volumetric throughput by measuring the velocity over the flow area. For low-viscosity products the velocity profile is flat and the flow velocity is nearly constant over the flow area, except for a region near the pipe wall (Figure 2a). Therefore, the average stream velocity can be measured at any point except near the pipe wall. As the viscosity increases and/or the flow decreases, the flow profile becomes parabolic (Figure 2b). Maximum velocity is at the center of the pipe and the velocity decreases gradually to zero at the pipe wall. To determine the average stream velocity for this type of profile, the stream velocity is measured at several selective points and the velocities are integrated with an algorithm to determine the average velocity. The relationship between velocity and viscosity is defined by Reynolds Number, which is the ratio of flowrate to the meter size and the viscosity {Re No ≈ (flowrate) / (meter size x viscosity)}

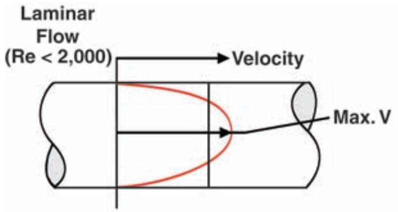

Figure 2a. *High viscosity*

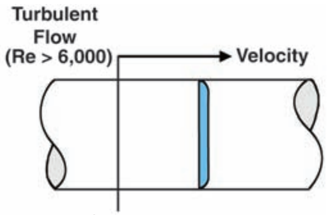

Figure 2b. *Low viscosity*

A select few multi-path liquid ultrasonic meters use velocity from four chordal paths (Figure 3) with the VPC to accurately determine the average velocity over the complete flow and viscosity range. Metering systems can also have valves, strainers, elbows, tees and headers upstream of the meter. These elements can distort the flow profile and introduce swirl and crossflow upstream of the meter. Since we are measuring velocity, any change in velocity created by these elements will affect the measurement accuracy. Flow conditioners are used to minimize these effects, but a robust integration method with crossflow compensation is also important to optimize performance. At least one liquid ultrasonic meter utilizes two additional paths with the VPC to correct for swirl and cross flow (Figure 4).

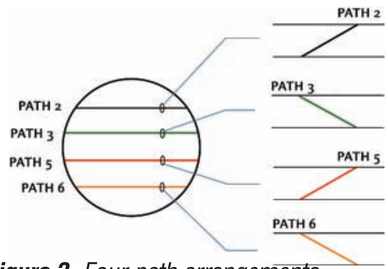

Figure 3. *Four-path arrangements for velocity profile correction*

Specifying an Ultrasonic Flowmeter

Key characteristics to look for in an ultrasonic meter for crude oil include:

- A multipath meter with an integration method like VPC to improve performance on high viscosity low Reynolds Numbers applications.
- Robustness in correcting asymmetric axial flow velocity profiles.
- Compensation transverse (non-axial) flow components (swirl, crossflow, etc.).

The key benefits of ultrasonic technology — i.e., low pressure and low maintenance — are highly attractive for crude oil measurement. They are driving the technology, but as with any meter there are limitations. Like turbine meters, ultrasonic flowmeters are best operated at the higher flow ranges for optimum accuracy, but with techniques like VPC accurate measurement is also achievable at the lower flow ranges. No pressure loss reduces operating cost. No moving parts increases service life and may reduce the frequency of proving, because usage wear is often the reason for recalibration.

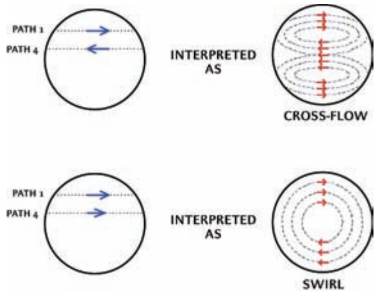

Figure 4. *Two (2) added paths for swirl and crossflow correction*

The measurement technique is susceptible to installation effects and fluid properties. As such, in-situ proving, though difficult, is the recommended method of proving to reduce total measurement uncertainty. Proving the meters in a laboratory offers an alternative, but at a substantially higher risk of measurement error. Even though a specific ultrasonic meter may compensate for installation effects, such as swirl or crossflow, there is no way to verify this capability without in-field proving.

Measurement accuracy may also be further compromised by the fluid property effects discussed earlier. This is particularly true for crude oils, because the properties of such applications are difficult to simulate in a laboratory. Before better and more quantitative knowledge is available on how ultrasonic flowmeters react to different fluid properties, the arguments advocating against in-situ proving and increased dependency on laboratory flow calibration (using water instead of hydrocarbons), are highly questionable.

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