EFFECTS OF FLUID PROPERTIES ON PIPELINE MEASUREMENT

Class # 2130

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Introduction

Measurement of liquid hydrocarbons in most pipelines today is done on a standard volume basis or by mass. These dynamic measurement points typically are custody transfer and are the “cash register” measurements between the two parties involved in the transactions. This is one reason why the measurement accuracy is critical with some others being product accountability and a “one time” dynamic measurement point. The volume or mass measurements must account for the entire liquid product received or delivered in order to track and determine if product is being lost or gained. Several fluid properties can change the accuracy of this measurement and knowing how they impact the measurement is crucial to its integrity. This paper will focus on dynamic measurement or measurement by metering and discuss several fluid properties and their affects on measured results involving the common types of metering technologies used today.

Measurement

Dynamic measurement performed by metering is essential to get right the first time. If the measurement is not correct, there is typically not a second chance to re-measure the product through the meter. Dynamic measurement increases the utilization of tanks and increases system efficiency because product does not need to sit as attributed to tank gauging.

Pipeline measurement is typically done in volume but could also be done in mass. The volume of liquid describes the physical space in which the product occupies such as a barrel, gallon or cubic meter. The mass would be expressed in weight such as lbs or kg. In either case, the measurement is only as good as the reference it is compared to and for meters, this means the prover. The prover is the tool used to calibrate the meter by comparing a known reference volume to an indicated metered volume. The ratio Actual / Indicated yields a meter factor.

Volume measurements are corrected to standard conditions which mean a fixed temperature and pressure. Most common for custody transfer is 60 deg F and 0 psig (atmospheric 14.696 psia). If we filled a 1 gallon container with 1/2 gallon of diesel fuel at 60 deg and 0 psig, we know that if we heated the liquid to 85 deg F, keeping pressure at 0 psig, the volume would increase its physical space inside the container. The opposite would be true if we cooled the diesel down to 30 deg F, we would have a decrease in volume. This is due to the expansion and contraction associated with all liquids which determines how much the volume will change per degree change in temperature. An example is outlined in the Table 1 below:

Table 1 – Corrected Volume to Standard Temperature Conditions

Diesel – 1 API 40	@ 85° F	@ 30° F
Indicated Volume	42.00 gal	40.89 gal
Temperature Correction API Chptr 11, Table 6 B	x 0.9878	x 1.0145
Volume at 60°F & 0 psig	41.48 gal	41.48 gal
Mass	294.09 lbs	294.09 lbs

Correcting volume measurements to standard conditions is necessary to eliminate the effects of temperature and pressure so the volume calculated will be at a reference for a transaction. Mass on the other hand would not change because we are not adding or removing physical product, only changing the space it occupies if heated or cooled.

Fluid Properties

Viscosity defined in simple terms is a liquids ability to resist flow in a pipe and is defined in terms of Dynamic (cP) or Kinematic (cSt) units at a specified temperature. The temperature is very important when collecting data on the viscosity of a liquid. The viscosity at min and max operating temperatures should be the minimum data collected. Product temperatures should be considered year round in regions with changing seasonal temperatures which can have an effect on viscosity values. The range gives an idea of how much or how little this property will change with changes in temperature.

High viscosity liquid products are described as thick and heavy, commonly attributed to crude oils, bunker fuels and asphalt. These would prove difficult to flow and pump at low temperatures but easier at higher temperatures which, is why it is common to heat these products, lowering their viscosity. Low viscosity products are described as thin and light such as gasoline, kerosene and ethane. These products flow easily in comparison and have smaller values of viscosity as seen in Table 2 below. As will be discussed, the viscosity will affect different metering technologies in different ways through its ability to flow.

Table 2 – Viscosity and Specific Gravity Values with Change in Temperature

	Typical Viscosity in cP** @Degrees F (Degrees C)						S.G.@Degrees F (Degrees C)	
Product	**30 (-1)**	**60 (15)**	**100 (38)**	**150 (66)**	**300 (150)**	**400 (205)**	**60 (15)**	**150 (66)**
Ethane -LPG	0.07	0.05	0.03				0.38	0
Propane –LPG	0.14	0.12	0.09	0.07			0.51	0.41
Butane – LPG	0.20	0.18	0.15	0.13			0.56	0.49
Gasoline	0.83	0.63	0.49	0.38			0.75	0.70
Water	1.8	1.2	0.7	0.4	0.2	0.1	1.00	0.95
Kerosene	3.5	2.2	1.7	0.9	0.4	0.2	0.82	0.77
Jet Fuel	3.5	2.2	1.7	0.9	0.4	0.2	0.82	0.77
48 API Crude	3.5	2.7	1.7	1.1			0.79	0.74
40 API Crude	10	7	4	2			0.82	0.77
35.6 API Crude	25	16	6	3			0.85	0.80
32.6 API Crude	42	21	9	5			0.86	0.81
Fuel 3 (Max.)		10	5	3	1	0.5	0.90	0.85
Fuel 5 (Min.)		16	7	4	1	0.6	0.97	0.92
Fuel 6 (Min.)		820	150	43	5	2	0.99	0.94
SAE 10 Lub		68	29	11	2	1	0.88	0.83
SAE 30 Lub		450	105	31	4	2	0.90	0.85
SAE 70 Lub			460	95	8	3	0.92	0.87
Bunker C			1500	290	16	5	1.01	0.96
Asphalt				>3000	80	19	0	0

*Data made available from the Crane Co.
**Centipoise (cP) = Specific Gravity (S.G.) x Centistokes (cSt).

Density & Specific Gravity are related and change in the same manner with temperature changes as seen in Table 3. Density is defined as the fluid's mass per unit volume at a specific temperature and is typically measured using an on-line Densitometer. Specific Gravity is a unitless ratio of the fluid density at a temperature to the density of water at 60 degrees Fahrenheit. The ratio or specific gravity of water is 1 which is why most hydrocarbons have a specific gravity less than 1 and therefore float on top of water. An increase in temperature will decrease the fluids density and specific gravity. This becomes critical when determining the volume correction factor correlated to the specific gravity listed in API tables for various liquid hydrocarbons.

Fluid Density also plays an important role when it is used to calculate volume by means of mass measurement whereby volume equals mass divided by density. This means that any inaccuracy in the density measurement directly translates to the volume measurement by this calculated relationship. Additionally, density will affect the fluid driving torque when related to a rotating element such as in a turbine meter. As the density decreases, it has less driving torque and therefore the fluid velocity or flowrate must be increased to compensate. This is why with low density products such as LPG's, the minimum flowrate must be increased in order to maintain turbine meter measurement accuracy. See Figure 1 for an example.

Table 3 – Specific Gravity and Changes with Temperature

SPECIFIC GRAVITY - REFINED PRODUCTS						
	S.G. @ deg F (deg C)					
Product	30 (-1)	60 (15)	100 (38)	150 (66)	300 (150)	400 (205)
Ethane - LPG	0.42	0.38	–	–	–	–
Propane - LPG	0.56	0.51	0.46	0.41	–	–
Butane - LPG	0.60	0.56	0.52	0.49	–	–
Gasoline	0.77	0.75	0.73	0.70	–	–
Water	1.03	1.00	0.99	0.98	0.92	0.86
Kerosene	0.84	0.82	0.80	0.77	0.74	0.72
Jet Fuel	0.84	0.82	0.80	0.77	0.74	0.72
Fuel 3 (max)	0.92	0.90	0.88	0.85	0.82	0.79
Fuel 6 (min)	1.01	0.99	0.97	0.94	0.91	0.88

Example - Low Density Application

- LPG Metering:
  3" Meter
  Normal Flow Range = 60 GPM to 600 GPM
  Extended Maximum Rate = 800 GPM
  LPG Specific Gravity = 0.5

$$\text{Rate Increasing Factor} = \left(\frac{0.9}{\sqrt{0.5}}\right) = 1.27$$

- New Flow Range = 76 GPM to 760 GPM
- New Max of 760 GPM is within Extended Max of 800 GPM

Figure 1 – Low Density Turbine Meter Application

Temperature of a fluid is one of the most critical properties that will affect our volume measurement since it dictates the changes in the fluid properties already discussed. This applies not only to the volume correction factor, but also the meter's performance to measure gross standard volume. This is why temperatures must be maintained during proving and continuously measured during the measurement process. Measurement accuracy of temperature should be within 0.5 degrees Fahrenheit resolution or better to minimize and account for the accuracy of the calculated volume.

Base Sediment and Water (BS&W) is measured by sampling over the batch or total measured volume. BS&W is mainly associated with crude oils. It indicates the percent of non-hydrocarbon product per unit volume present so it can be subtracted from the total volume measured. This is important since it is desired to only measure and pay for the liquid product being transferred. Sampling is typically driven by the volume passed through the meter.

A simple example may be that a sample is taken every 100 barrels out of a 1,000 barrel delivery. The 10 samples are collected in a single container which is then analyzed on line or by a laboratory for the BS&W. Most pipeline quality crude has less than 1% BS&W. This property becomes important to the metering technology employed as it can increase meter wear and impede the operation of ultrasonic meters. In ultrasonic meters, the signal generated by the transducer can be deflected by the sediment or water, to which the signal would be reduced or not received affecting the measurement accuracy.

Vapor Pressure is simply defined as the amount of pressure required to keep a fluid in a liquid state. If the fluid pressure goes below the vapor pressure, the liquid can change into a gas which is sometimes referred to as flashing. Table 4 below shows some common fluids and their vapor pressures as affected by temperature.

Table 4 – Liquid Product Vapor Pressures

VAPOR PRESSURE			
Product	API	Vapor Pressure (psi)	
		60° (15°C)	100°F (30°C)
Propane	150	105	184
Butane	110	26	50
Gasoline	60	10	20
Diesel	40	5	10
Crude Oil	10 - 45	5	10

Entrained Gas can be described as the amount of gas present per unit volume of liquid. In the production stage, crude oil can often be mixed with gases. This mixture commonly enters a separator which allows it to develop into two single phases, gas and liquid. From the separator, each phase can be measured. Separators are not 100% efficient in this process and commonly gas carry under occurs in which entrained gases are measured with the liquid and continue through the pipeline process unless allowed to sit in tankage. The more viscous or thick the product is and the amount of pressure on the liquid, dictates how long it takes for the gas bubbles to separate out. Lower viscosity liquids allow the gas to separate out more quickly and efficiently during the separation process. It becomes obvious that liquid volume measurement accuracy will rely on the absence of entrained gases.

Most metering technologies can accommodate entrained gases, meaning that it will not affect the meter function but will affect the volume since the gas bubbles take up space. The entrained gas can affect mass measurement if it is not evenly distributed throughout the liquid and between the two tubes in a Coriolis meter. It will also cause a density deviation due to the fact that the gas bubbles take up space in the fluid flow and will cause a proportional error in volumetric flow calculation. The entrained gases will also attenuate or absorb the ultrasonic sound signal in a UFM (Ultrasonic Flow Meter). The degree of attenuation depends on a number of factors such as pressure, distribution, bubble size, amount of free gas, signal frequency, etc. As with all liquid custody transfer flow meters, removing or accounting for entrained or slug gas is critical to volume measurement accuracy.

Cloud Point is defined as the fluid temperature at which wax or paraffin solids begins to form. Paraffin or wax would need to be present in the fluid base for it to fall out typically at cooler temperatures. If paraffins are present, the liquid product temperature must be kept above the cloud point temperature in order that waxing does not occur. If a meter is operated below the cloud-point, wax can form on the measuring element and can significantly decrease a meter's ability to measure accurately. Making sure this fluid property is determined through laboratory testing is critical to the design and operation of the measurement system. The best method to reduce the chance of waxing is to assure the system is operated above the cloud point temperature of the liquid.

Metering Technologies

Positive Displacement Meters

PD's directly measure volume by segmenting flow into calibrated volumes and counting rotor revolutions. The calibrated volume is determined by proving the meter insitu at operating conditions. These meters are mechanical by nature and therefore perform based on small clearances between the moving parts. Fluid properties that primarily affect accuracy are viscosity, temperature and contaminants such as sediment and water which will contribute to wear and should be minimized.

As seen in Figure 2, a PD meter measures the volume throughput except for a small amount that slips through the clearances. The meter is then calibrated or proved on a product at operating conditions to eliminate the slippage error. Because slippage through clearances is dependent on viscosity (ability to slip), once the fluid is above a limit, the slippage error decreases to zero. This means the PD Meter Factor (MF) will remain constant and the meter can accurately measure over a wide operating range making it ideal for most pipeline crude oil applications.

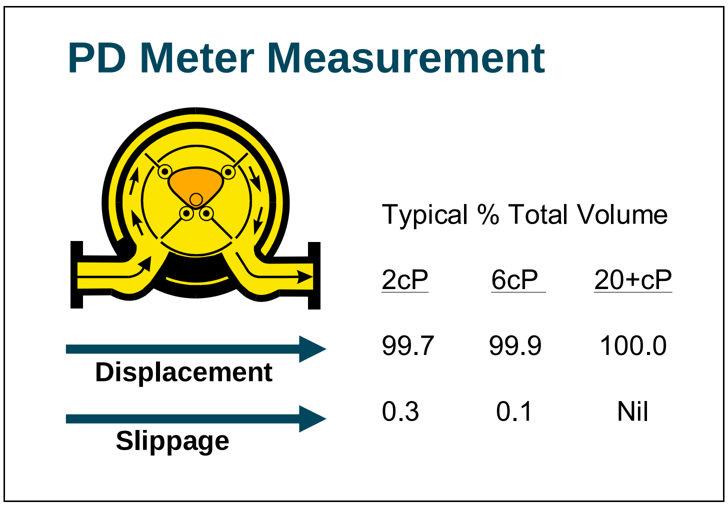

Figure 2 – PD Meter Slippage

Note as the viscosity increases it becomes too thick to pass though the meter clearances so the slippage error is virtually eliminated. As seen in Table 5, the measurement turndown range is a product of the flow turndown x viscosity turndown and increases as the viscosity increases.

Conventional Turbine Meters

Turbine meters determine flow rate by measuring the velocity of a bladed rotor suspended in the flow stream. The volumetric flow rate is the product of the average stream velocity and the flow area at the rotor as related by the basic equation:

$$\text{Volume Flow Rate} = \text{Velocity} \times \text{Area}$$

The accuracy of a turbine meter is based on two assumptions: (1) Rotor velocity accurately represents the stream velocity (2) Flow area remains constant.

There are a number of fluid factors that can affect the rotor velocity such as; rotor stability if wax is present, bearing friction if fine particulates are present and fluid density from changes in temperature or products themselves run in a pipeline.

The effective rotor flow area, and thus the meter's "K" factor (pulses / unit volume), can change for any one or a combination of the following reasons. The two major factors that affect measurement accuracy in a pipeline with turbine meters are:

- Deposits or Waxing - Small amount of buildup on the rotor blades can have a significant effect on meter performance. For example, a one mil (0.001”) buildup on the surfaces of a 4” conventional turbine rotor will decrease the flow area through the rotor, and increase the “K” factor, by about 0.5%.

- Boundary Layer Thickness - Boundary layer thickness is relatively constant and insignificant when operating on products with low viscosity such as refined products or light crude oils. But as the viscosity increases, the boundary layer increases which reduces the effective flow area. In fluid dynamics this effect is defined by the Reynolds’s Number (Re No), which is the ratio of the inertia forces (the force of the flow stream) to the viscous forces (the resistance to flow). Reynolds Number can be expressed as:

$$^{*}Re = \frac{2214 \text{ x Flow Rate (BPH)}}{\underset{\text{(Inches)}}{\text{Diameter}} \text{ x } \underset{\text{(cSt)}}{\text{Viscosity}}}$$

Typically conventional turbine meters are operated with a flow turndown of 10:1 (minimum flow of 1/10 of maximum flow) and at Reynold’s Numbers greater that 40,000. The meter viscosity range is also limited to no more than two times line size in Kinematic viscosity. For example, a 6 inch conventional meter has a limit of 12 cSt in which the normal minimum flowrange will be increased by the ratio of viscosity / meter size seen in Figure 3. This narrows the flow turndown range as viscosity increases due to Reynold’s number and boundary layer.

High Viscosity Application

- Viscosity (cSt) ≤ Line Size (in.)
  Normal Flow Range Applies

- Line Size (in.) ≤ Viscosity (cSt) ≤ **2X** Line Size (in.)
  Low Flow Rate Must Be Adjusted For Viscosity:

$$\text{Viscous Min. Rate} = \left(\frac{\text{Viscosity}}{\text{Line Size}}\right) x \text{ Normal Min. Rate}$$

Figure 3 – Viscous Minimum Rate Calculation for Turbine Meters

Helical Turbine Meters Helical turbine meters are similar to conventional turbine meters in the fact that they have like housings, stators, bearings and pulse pickup systems and are governed by the same laws of fluid dynamics. They vary in one distinct area - the rotor has only two helical blades instead of multiple blades.

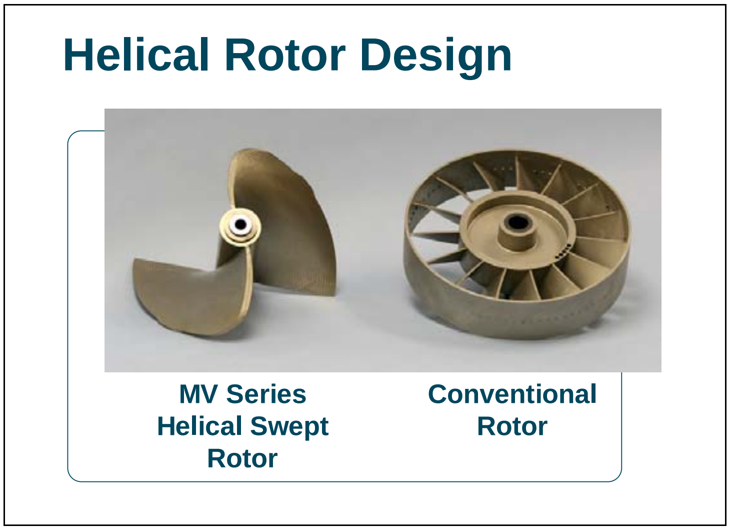

Figure 4 – Helical and Conventional Turbine Rotors

The two-bladed helical rotor gives the meter the ability to accurately measure higher viscosity liquids because of the reduced effect of the stagnant boundary layer which builds up on rotor surfaces when higher viscosity oils are being measured. Figure 5 shows a comparison of the change in flow area with a 0.001" change in the thickness of the boundary layer between an 8" conventional and helical turbine meter rotors. The change in flow area directly affects stream velocity through the meter and, therefore, the relationship to rotor spinning velocity. The effect is over three times greater with the conventional turbine meter.

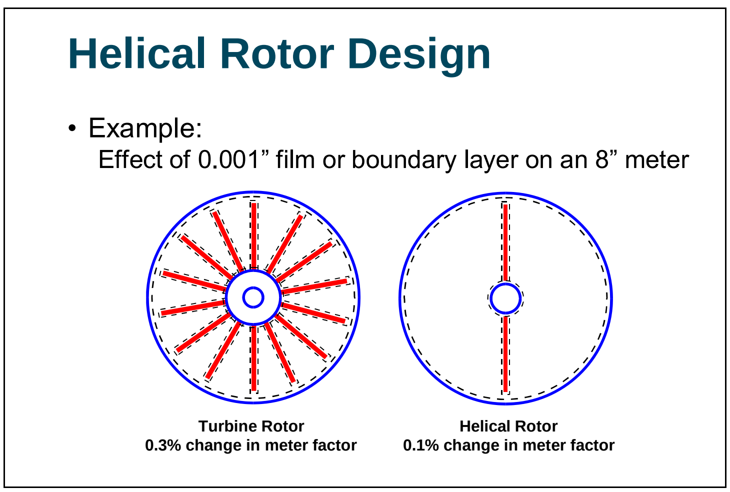

Figure 5 – Boundary Layer Affect on Turbine Rotor Surface Area

Typically helical turbine meters are operated to Reynolds Numbers as low as 10,000 with special tuning. They can also be characterized and the output viscosity compensated to measure a wide rate on viscous crude oils e.g. less than API 20.

Coriolis Mass Meters

To accomplish a volume measurement a Coriolis meter transmitter calculates volume flow rate (Q) from measured mass flow rate (m) and measured density (ρ): $Q = m / \rho$. The Coriolis meter volume measurement accuracy reflects the combined uncertainty of the mass flow rate and density measurement.

To measure density, the Coriolis meter measures a change in frequency of the vibrating tubes as compared to a reference density. The reference density is calibrated at the factory on air and water as most hydrocarbons have a density lower than water but greater than air. The higher the fluid density, the lower the frequency of vibration and the lower the density, the higher the frequency as seen in Figure 7.

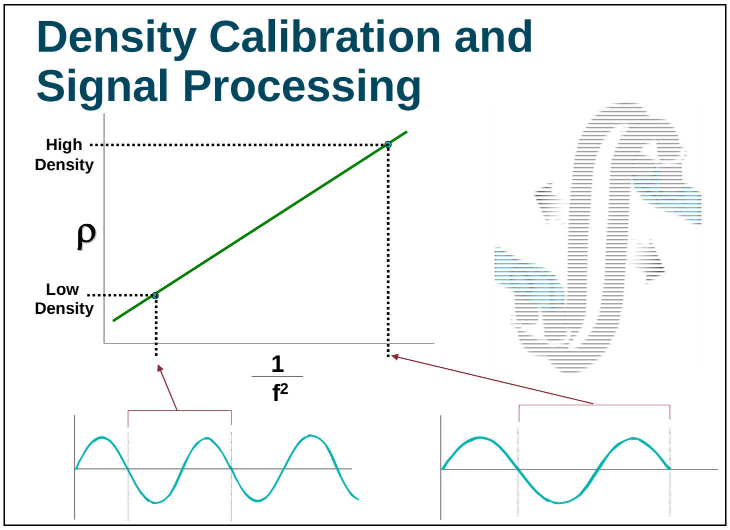

Figure 7 – Coriolis Density Measurement

Based on this outline of operation, the mass and volume measurement is not affected by viscosity or lubricity of the fluid. It should be noted that due to the tube bends, pressure drop across the meter will increase as viscosity increases and does not have a linear relationship. This needs to be considered for pump energy costs on heavy products as well as cavitation on light products. The pressure drop should not exceed the vapor pressure of the product and correct back pressure should be applied to avoid cavitation.

Since Coriolis mass flow meters do not contain any internal wear parts, they are far less susceptible to fine contaminates such as sand, which can significantly decrease the life of PD or turbine meters. Coriolis flow meters are successfully applied to harsh production crude oil applications and asphalt loading terminals where the high operating temperatures and particulates make it a difficult application for alternative meter types.

Transportation and Marketing Terminals for LPG, LNG and NGL **–** Coriolis meters have two advantages over turbine meters which are traditionally used in these applications:

1. The volume of these products is highly affected by both temperature and pressure. As such, the output must be pressure and temperature compensated to provide accurate measurement. Coriolis mass meters are relatively insensitive to these parameters so they can provide an accurate measurement over a wider measurement range. If the custody transfer is in mass units, which is common for these fluids the measurement accuracy may be further increased because the density does not have to be determined to convert the output to volume units.

2. Because the Coriolis meters contain no internal wear parts, they have a highly favorable service life when applied to dry, low lubricity fluids. Dry products are ones that have a very low lubricating quality which cause accelerated wear on bearing systems.

Liquid Ultrasonic Flow Meters

Ultrasonic meters, like turbine meters, are inferential meters that derive flow rate by measuring stream velocity. Volume through-put is then calculated by multiplying the velocity by the flow area as shown by the following equation:

Volume Through put (Q) = Velocity (V) x Area (A)

Refined Products and Light Crude Oil High Volume Through-Put Applications – The advantages of Ultrasonic Meters make them well suited choice for high volume applications such as pipelines and ship loading / unloading facilities. Like turbine meters they are best operated at the higher flow ranges for optimum accuracy. No pressure loss reduces operating cost. No moving parts increases service life and may reduce the frequency of proving because wear can be a key reason why meters are recalibrated. Like turbine meters ultrasonic meters:

- Can handle higher through-put than PD meters or Coriolis mass meters of equal size.
- Are practically well suited for LPG applications because of no moving parts and their compact tubular design make them economical to manufacture for higher operating pressures.

Transportation of Crude Oils – the advantages of Ultrasonic Meters make them an ideal choice for the transportation of crude oil especially for the harsh applications where the crude oil has entrained particulates which can significantly reduce the service life of PD meters. There are limitations to using Ultrasonic Meters in these applications, which include:

- Products with entrained solids or gas can attenuate or fully block the signals. Typically, BS&W and entrained gas is limited to 5% and 1%, respectively, but even less amounts can significantly affect the meters performance.

- High viscosity products can affect the meter in two ways.

    1. Highly viscous products can attenuate or block the signal. Since the acoustical path lengths vary with meter size, each size has a maximum viscosity which is stated by the manufacturer.

    2. Like Turbine Meters, Ultrasonic Meters are affected by boundary layer thickness. With medium to high viscosity products this effect must be compensated to achieve accurate measurement. . Multi-path Ultrasonic Meters have methods to minimize this effect but some methods may be more robust then others. Even with these compensation methods there is a transitional region where the velocity profile can change significantly under the same dynamic conditions.

Conclusions

Measurement accuracy is critical to custody transfer applications and the accountability of liquid products. The measurement is dependent on accurate specific gravity and gross volume. Fluid properties will affect the gross volume depending on the type of meter technology that is selected. Understanding the fluid properties of the application as well as the desired operating conditions in the design stages of a measurement system is critical for accuracy as well as flexibility. Once the fluid properties are understood for current and future conditions, a proper metering technology can be selected based on viscosity and flow range that inherently gives the greatest accuracy. Monitoring the fluid properties and meter performance will give insight into changes in measurement accuracy which can be accounted for and corrected through proving.

References

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2. API Chapter 5 Metering
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4. FMC Technical Paper, “A Comparison of Liquid Petroleum Meters for Custody Transfer Measurement”, by Ray Kalivoda, June 2007