The Developing Role of Liquid Ultrasonic Custody Transfer Meters

Philip A Lawrence
NuFlo Measurement Systems
Houston
Texas

Abstract

The use of electronic metering technology in the oil and gas industry is gaining popularity and more acceptance as the improvements in microprocessor speed and technology advances.

Over the past ten years reliability reproducibility and consistency of microprocessors have developed to such an extent that it's possible to produce very reliable black box type equipments whereby the end-user may not see or get a feel for what is happening in the meter operation, but can see results that are accurate and provide good uncertainty.

Multi-Path ultrasonic flow meters have this trait and have gained acceptance for many fiscal applications.

In October, 2002 the API committee on petroleum measurement published a draft standard named Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meter Using Transit Time Technology.
In October, 2004 a revised version of this draft was accepted as a full standard.

Chapter 5.8 was voted for, and accepted by the API membership and is included in the API and Manual of Petroleum and Measurement Standards today.

This paper will discuss some of the ways this new technology is changing the techniques in precision low maintenance petroleum measurement.

Ultrasonic Measurement Principle

The principle by which fluids can be measured in a pipe using ultrasound is quite simple.

The development of the technology has only just become more viable due to faster processing times.

The basic idea or theory is very simple, if a sound pulse is sent in the direction (with) of the flow the time the pulse taken to get between two fixed locations will be faster than if there is no flow.

When a signal is sent in the opposite direction (against the flow) the time will be longer because of the opposing flow velocity.

The difference in the time taken is related to the proportion of fluid velocity acting along a line between the two locations.

This is what we call the transit time measurement principle.

Transit time measurement should not be confused with reflective types of ultrasonic meter which bounce a sound wave through the pipe and collect the data on the exterior of the pipe wall (clamp on meter) because the pipe and subsequent locations for transmitting and receiving can change due to temperature and also density changes in the fluid being measured which can affect the velocity of the sound waves.

The positioning of ultrasonic transducers in a pipe can be diametrically opposite and are angled, usually at 45°, this allows precision transmission and reception of the ultrasound pulses to propagate through the fluid.

The timing data can then be integrated to give a mathematical answer for velocity flow rate, proper transmission and reception without movement of the transducers is key to obtaining good performance with this type of technology.

Fig 1.0 shows the way that this can be achieved with precision .By using multiple paths or multi-chordal path ways in the pipe further enhancements can be offered.

Transit Time Principle and Operation

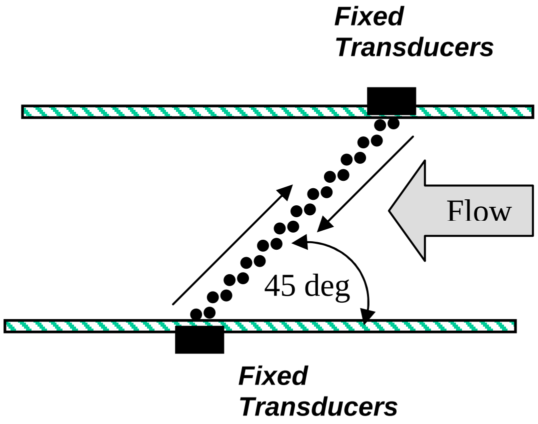


Fig 1.0 (*Single Path Shown*)

The transit time measurements are taken in rapid succession (several times per second) and this will allow the determination of the average velocity in the pipe (assuming good velocity profile) to be determined thus see fig 2.0 :-

$$V = \frac{PathLength * \Delta T}{2(Tup * Tdown)\cos\phi}$$

Fig 2

Where: - V = Path Velocity
ΔT = Top –Town
Φ = Path Angle

There can be issues caused by fluid dynamics in pipes , Velocity Profile , Reynolds Number and also product consistency which can affect all inferential meters hence some manufacturers have moved to multiple path devices which have distinct advantages which we will discuss.

$$V(Pn) = \frac{PathLength * \Delta T}{2\left(T_{up} * T_{down}\right)Cos\phi}$$

Fig 3

Pn =Path numbers

The use of multi-path transducers enable some of the issues caused by velocity profile to be solved mathematically **See *fig 3.0, Figs 4.0, 5.0 & 5.0a***

The following equation indicates how the individual path velocities can be integrated into an average velocity multiplied by the average approach velocity in the spool, to determine a volumetric flow-rate in the meter (**fig 4.0**)

$$Q = PF \sum_{i=1}^{4} k_{bi} V_i * A$$

Fig 4.0

Where: - Q = Volumetric Flow Rate
PF = Profile Factor
K*bi* = *Weighting* Factor
V*i* = Path Velocity
A = Meter X - Sectional Area

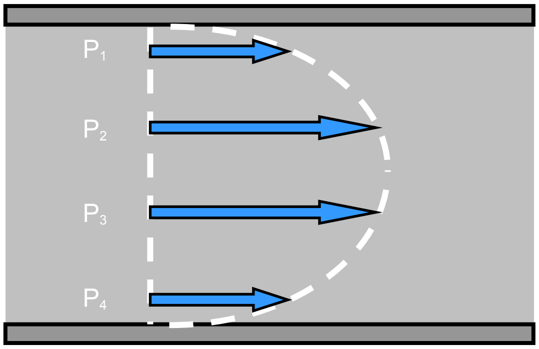


Fig 5.0

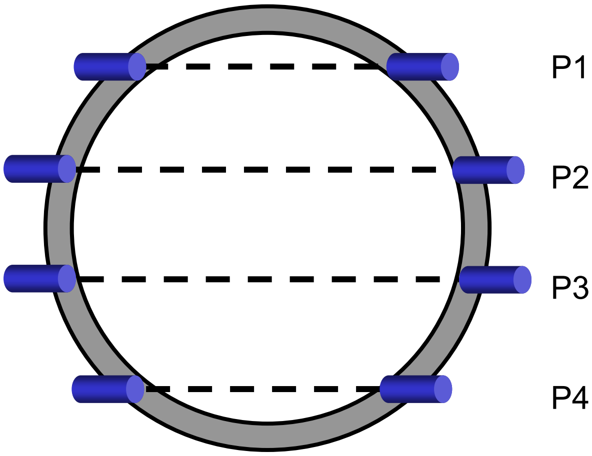


Fig 5.0a

Typical Multi Path Chordal Meter

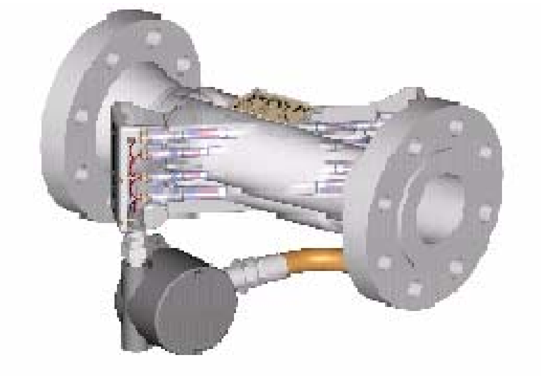


Fig 5.0

Ultrasonic meter designs require good mechanical stability for the transducer supports and body because the timing data collected is in the order of 10s of milliseconds diametrically in the meter throat.

In the drawing above (fig 5) you can see that stability is inherent in this particular design because, the transducer support structure is an integral part of the main body of the meter. With this design transducer miss-alignment issues are minimized!

Liquid Custody Transfer

Liquid Custody Transfer is one of the most demanding measurement problems today particularly due to the high prices of crude oil (circa 70$/Bbl).

A typical example using even a mid size meter measuring say crude oil at 795m3 /.hr (5000Bbl/hr).

With an uncertainty or error of just 0.1% the annual financial impact would be over $1 million US.

It is important to make sure with this level of financial risk to put into place a good fiscal measurement policy and strategy.

Many manufacturers of newer technologies claim that their meter does not need a calibration checking device (prover) , this can be a risk and it becomes increasingly evident that share holders and stake holders in the oil market require that transfer of hydrocarbons that attract duty and also have legal transfer agreements have a method to verify the transaction.

Proving of Electronic Meters

Currently there is no type testing or legal verification for newer black box type electronic meters in the USA. The advent of API 22.2 allowed the performance testing of newer differential pressure devices to this standard enable easier user approval.

The big issue is that not all meters are the same or perform the same even though the API MPMS chapter 5.8 details steps for the usage and implementation of ultrasonic devices, it leaves the user to verify that the meter design and installation is sound.

The bigger issue on all user lips at this time is that of proving, the old adage time is money is really true when you consider the current issues of manufactured electronic pulses and how quick they are transmitted.

Some of the issues that can affect a meter during its normal operation are:-

a) Internal fluid dynamic effects (vortices and swirl)
b) The flow rate region related to Red No particularly in the transition zone.
c) Upstream disturbance effects
d) Geometric stability
e) Pulse output from the processor during proving.

Unlike Pd Meters or Turbine meters which have “fluidic inertia “which tends to smooth out minor fluid variations in velocity and vortices in the fluid streamlines.

The Ultrasonic meter see’s all the fluid variations it’s very much like photographing a snap shot of the fluid movement in the pipe in real time variations and all

The more samples taken (faster update and Integration time) and faster transducer transmit and receive times the better the picture of what is happening in the pipe and thus a better fluid flow rate number is obtained.

The variations can affect the repeatability and accuracy of the device if not taken into account by a method called characterization.

Ultrasonic Meter Repeatability

To obtain a true measure of velocity when using an ultrasonic device many samples must be taken of the velocity profiles in the meter throat and corrections made.

The more samples per time unit the better the flow answer. When comparing with a prover device also time dependant it is important to obtain the correct prover size.

Figure 6.0 shows the repeatability for various proverb volumes per meter size. From the chart it can be seen that the repeatability of an 8 inch diameter electronic meter using a 130 Bbl prover size would obtain a repeatability of 0.05 with 5 runs.

If a smaller prover was used say 40Bbl then the repeatability for the same runs is 0.12 so 10 runs are needed to obtain the same uncertainty.

Prover Size V's Meter Size

Prover Volume vs Meter Size

	5 Runs 0.05%	8 Runs 0.09%	10 Runs 0.12%	15 Runs 0.17%
Meter Size (in.)	Prover Size (bbl)			
4	33	15	10	6
6	73	34	22	14
8	130	60	40	25
10	203	94	62	39
12	293	135	89	56
14	399	184	121	77
16	521	241	158	100

Fig 6.0

Figure 7.0 shows the number of prove runs to meet the API.MPMS chapter 4.8 table a - 1. Repeatability requirements.

It is known that it requires more runs to prove an electronic meter than a mechanical type however the frequency of proving may be reduced because the meter has no moving parts to wear change its meter factor.

Other factors beneficial for this technology are the diagnostic ability and fluid property information that cannot be derived from a mechanical meter.

Repeatability of Proving Runs

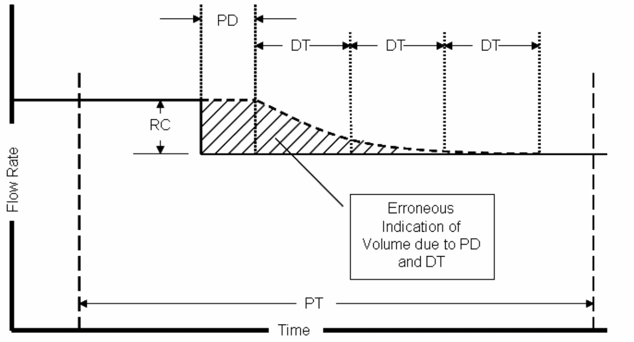
API Chapter 4.8, Appendix A

Proving Runs	Repeatability Limit	Meter Factor Uncertainty
3	0.02	2.7/10,000
4	0.03	2.7/10,000
5	0.05	2.7/10,000
6	0.06	2.7/10,000
7	0.08	2.7/10,000
8	0.09	2.7/10,000
9	0.10	2.7/10,000
10	0.12	2.7/10,000
11	0.13	2.7/10,000
12	0.14	2.7/10,000
13	0.15	2.7/10,000
14	0.16	2.7/10,000
15	0.17	2.7/10,000
16	0.18	2.7/10,000
17	0.19	2.7/10,000
18	0.20	2.7/10,000
19	0.21	2.7/10,000
20	0.22	2.7/10,000

Fig 7.0

Manufactured Pulses and Delay

Fig 8.0 below shows some reasons for the delay in pulse output from UFM'



$$Error(\%) \leq RC\frac{(PD+DT)}{PT}$$

- Fundamental Pulse Delay or Sampling Period (PD)
- Dampening Filter Time Constant (DT)
- Proving Run Time (PT)
- Flow Rate Change (%) during the Prove Run (RC)

Meter Characterization

The fact that there are no moving parts in UFM's means that it is possible to characterize the meter for different fluid viscosities and store the fluid dynamic performance data in the meter memory

Reynolds Numbers hold true for both liquids and gasses over ranges that are above the transition range 4000 Red.

It is possible to laboratory prove the device using flow and installation conditions to obtain superior performance per Reynolds number rang-ability.

It is possible to test UFM's at various laboratories from viscosities of 0.5 -120cst and obtain linear results over all ranges inside these viscosity ranges.

Diagnostics and Performance.

The meter can electronically read the viscosity, density and correct in real time for any ReD effects on the velocity profile.
This is some of the real time benefits offered by this technology over other types of mechanical measurement devices.
The monitoring of the flow paths, flow profile and standard deviation of the path velocities enable a meter diagnostic mode on some UFM's.
This benefit was seen in a recent set of data obtained from a client whom had a partially blocked flow conditioner plate. Figs 8.0, 9.0, 10.0 & 11.0

Normal Velocity Profile

Flow Profile Std Dev of Path

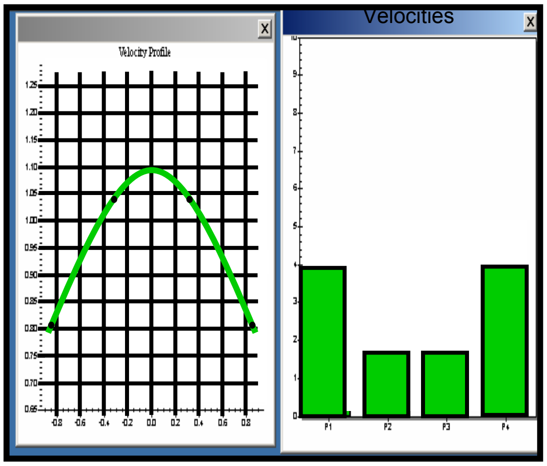


Fig 9.0

Abnormal Velocity Profile

Flow Profile Std Dev of Path

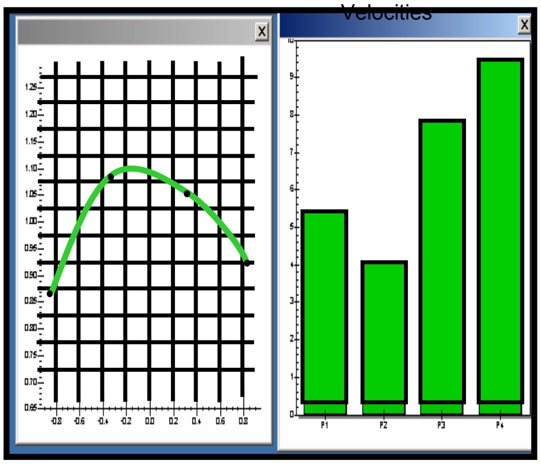


Fig 9.0

The actual problem as follows:-

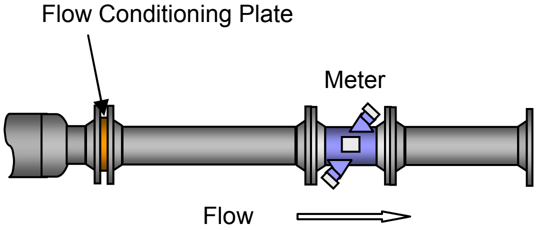


Fig 10 .0

Trash Blocking a Flow Conditioner

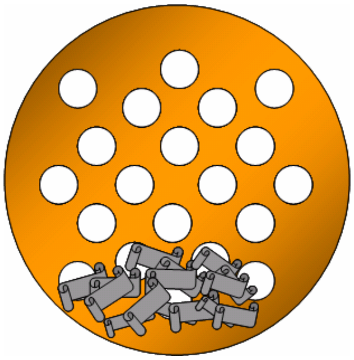


Fig 11.0

UFM Fluid Properties Measurements

The following parameters can be monitored with sufficient accuracy to be useful if the UFM is designed to collect the data.

Density

- Correlates with VOS (Velocity of Sound)
- Uncertainty - ~ +/- 0.025 g/cc (good repeatability)

Viscosity

- Correlates with VOS and Attenuation
- Uncertainty - ~ +/- 3 to 4 cSt (good repeatability)

VOS

- Fluid Turbulence (Std Dev of Path ΔTs)
- Flow Profile
- Swirl

Prover Connections and Its Effects

API MPMS recommend that prover take of connections for turbine runs be placed downstream of the meter. If a bidirectional prover been used these recommendations cannot be followed.

Fig 12 shows how normalized velocities through the meter throat become erratic when the flow is diverted through the prover and upstream of the meter run. It is clear that the flow conditioner has not eliminated the effects of the change in hydraulic condition.

This may attributed to swirl in the system

For the Caldon UFM LEFM 240C the equation to determine swirl is as follows :-

$$Swirl = \frac{1}{2}\left[\frac{v_1 - v_4}{2y_{1-4}} + \frac{v_2 - v_3}{2y_{2-3}}\right]$$

Were :- v = Each Normalized Path Velocity
y = Radius of the paths

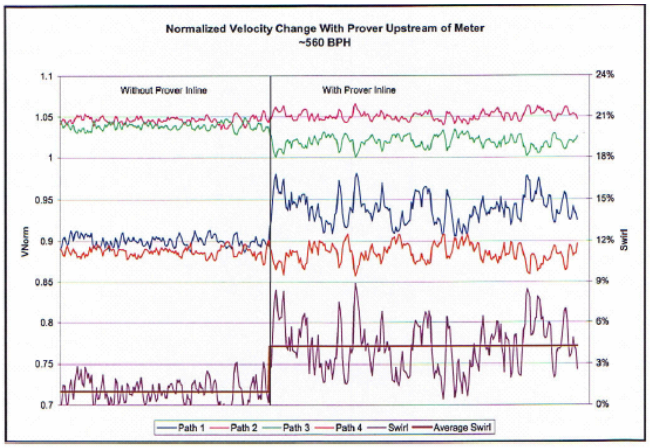


Fig 12.0

Dual Multi Path Meter Designs

Further enhancements to the technology are the use of cross correlated meter designs. In reality this configuration is in fact two meters placed in the same pipe geometry.
These meters usually have ultrasound path geometries in opposition.

This allows the deviation caused by swirl or disturbance effects to be minimized by adding the results from both meters and halving the answer.

Below is a typical meter see Fig 13.

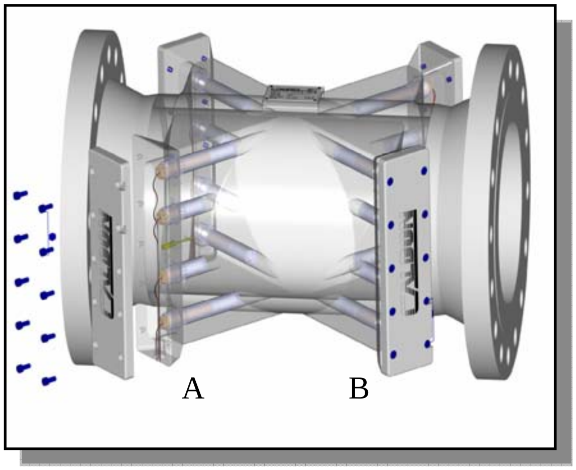


Fig 13

Minimising Velocity Profile Bias

$$\textbf{Meters : } \frac{A + B}{2} = C$$

This type of dual orientation can give a master meter performance provided the meter has constant path geometry and uses "Gaussian - Quadtrature" integration techniques.

The proving aspects are then greatly reduced with this design due to the reduction in velocity profile bias or swirl.

Were space is at a premium, the use of short meter runs with elbows is a reality without a prover.

Conclusion

Ultrasonic metering technology shows much promise as a bona-fida method to measure pipeline quality crude oils and refined products to a high degree of accuracy with minimum maintenance.

Care must be taken in dealing with installation effects (unless dual type meters are used) as is the need for most turbine meters.

We shall see the development of the technology grow and are already seeing world wide acceptance for these types of device based on type testing.

References:-

Hayward A Source Guide For Users 1978 (Alan Hayward)

Miler Handbook (R W Miller) current Edition

Accuracy Diagnostics of liquid Ultrasonic Meters ISHM 2004 (Chris Laird Caldon Inc)