

FLOW METER SPECIFICATION AND APPLICATION ANALYSIS

Class #41

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1.0 Introduction

Today's working environment results from numerous mergers and acquisitions, retiring baby boomers, fewer resources and less time to fully understand metering technologies and applications. There is growing dependence on product manufacturer's and vendors to provide complete solutions that fully comply with industry standards such as API, AGA and Measurement Canada. To increase profitability, accurate and repeatable flow measurement is required for both process control and custody transfer applications. A 1% reduction in raw material that flows at 10 liters per minute and costs \$1.00 per liter generates a cost saving of \$52,560.00 per year assuming 24/7 operation 365 days a year. A 3" ultrasonic meter that flows 25 MMSCF/D of natural gas at \$9.00 / thousand SCF equates to \$6,750,000.00 per month. Improving the accuracy by 1% will work out to a difference of \$67,500.00 per month.

There is often more than one flow metering technology to choose from for a given process application, and it's important to understand the characteristics of each as well as the application at hand. A flow meter that is misapplied will likely not perform well, regardless of the technology, and may result in higher energy costs, lost and unaccounted for production, or complete failure. This paper will cover general operating principals of new technology meters which, when combined, cover approximately 95% of all metering applications. A few have existed for 30 plus years, and all have undergone major advancements. They include coriolis, magnetic, ultrasonic and vortex shedding. This paper will provide guidance to properly determine what metering technology(s) are best suited for your custody transfer or process control application as they pertain to the oil and gas, petrochemical and refining industries.

2.0 Definitions

Accuracy – The ability of a measuring instrument to indicate values closely approximating the true value of the quantity measured.

Repeatability – (a) Metering - The closeness of the agreement between the results of successive

measurement of the same quantity carried out by the same method, by the same person, with the same measuring instrument at the same location, over a short period of time. More specifically, the ability of a meter and prover system to repeat it's registered volume during a series of consecutive proving runs under constant operating conditions. (b) Laboratory Test Method – The difference between successive test results obtained by the same operator, with the same apparatus, under certain operating conditions, on identical test material using the same test method.

K Factor- The K factor is the ratio of the meter output in number of pulses to the corresponding total volume of fluid passing through the meter during a measurement period. The K factor can be expressed as the ratio of the meter's output frequency to the corresponding flow rate during the measurement period. The meter factor is equal to 1/K. The K factor may change with pressure and thermal effects on the body of the meter. The manufacturer of the meter should be consulted regarding changes in K factor, if any, that occur between liquid and gas, or between one pipe schedule and another.

Linearity – Linearity refers to the constancy of the K factor over a specified flow rate. A band defined by maximum and minimum K factors usually specifies this linear range, within which the K factor is assumed Kmean. The upper and lower limits of this range can be specified by the manufacturer as either a maximum and minimum flow rate range of a specified fluid, or other meter design limitations such as pressure, temperature, or installation effects.

If pressure and temperature are to be measured, the techniques should not interfere with the flow meter's performance. The manufacturer should be consulted regarding these measurement locations.

Range ability – Flow meter range ability is the ratio of the maximum to minimum flow rates or Reynolds number in the range over which the meter is linear. Range ability is frequently referred to as *turndown*. The manufacturer should be consulted regarding any effect on performance if the meter is to be used outside of the linear range.

Reynolds number – The relationship between velocity, density, and viscosity, and defines the state of flow. Pipe Reynolds number is a dimensionless ratio of inertia to viscous forces, which is used as a correlating parameter. It is defined as:

$$ReD = \frac{DUQ}{\mu}$$

Where, in compatible units:

D = unobstructed bore diameter

U = average velocity of fluid in the unobstructed meter bore

Q = fluid density

μ = Absolute (dynamic) viscosity of the fluid

Pressure loss – Pressure loss is caused by the frictional losses associated with fluid motion in internal passages. The manufacturer should be consulted for pressure loss values to be expected and how they were determined (including pressure tap location).

Cavitation – For liquid, cavitation bubbles may form when the fluid pressure is close to the vapor pressure. Local lowering of pressure occurs when the fluid velocity is increased by the decreasing cross section around the strut(s) of a meter. Prolonged cavitation will cause structural damage to the flow meter. The manufacturer should be consulted for the minimum backpressure or other specification to avoid cavitation. These may be in the form of equations that include vapor pressure for the fluid being measured, and peak pressure drop in the flow meter.

Velocity – The rate of motion in a particular in relation to time. Expressed as ft/s or m³/s.

Frequency – The rate in which vortices are generated off the shedder bar. The frequency is directly proportional to the flow rate.

Viscosity – The internal resistance of a fluid to flow. For liquids, viscosity decreases as temperature increases. For Gas, the viscosity increases as temperature increases. The greater the viscosity, the lower the Reynolds number.

Laminar Flow – Values of Reynolds number below 2100 characterize laminar flow. The velocity profile for fully developed laminar flow is parabolic with maximum fluid velocity occurring at the centerline of the pipe and decreasing to zero at the pipe wall. The fluid velocity at centerline is twice the value of the average velocity in the pipe.

Turbulent Flow – Characterized by Reynolds numbers over 3000. As Reynolds Number

increases from a laminar to turbulent region, the velocity profile flattens. Eventually, all fluid particles travel at a uniform velocity (except near pipe walls).

Transition Flow – Characterized by Reynolds Numbers between 2100 and 3000. Flow takes on the properties of both laminar and turbulent characteristics in this region.

Swirl – Represents angular momentum of a fluid that results in rotational flow about the pipe axis. Swirl is the effect of fluid flow through different combinations of pipefittings, such as two elbows close coupled and at 90 degrees out of plane.

Primary Element – A device inserted in the pipe line to develop a mechanical, electrical or hydraulic force for the purpose of measuring flow.

Secondary Element – A transducer which amplifies a signal from a primary element.

3.0 Metering Technology Overview

Flow Meters

There are generally two types of flow meters, energy extractive and energy additive. Energy extractive flow meters require energy from the process medium to operate, generally in the form of pressure. Examples are differential pressure, vortex, positive displacement and turbines. Energy additive meters induce energy into the flowing stream such as coriolis, ultrasonic and magnetic.

Further classification would include inference or discrete metering technologies. Discrete meters separate the flowing stream into segments and count each segment. Inference meters infer the flow rate usually by some dynamic property. The space between turbine meter blades is considered a segment, and each time a blade passes an electronic pick off, one segment is counted. This is considered a discrete flow metering technology. Ultrasonic flow meters are considered inferential as they infer velocity by calculating the time difference of the downstream and upstream ultrasonic signals. The volumetric throughput is then mathematically calculated by multiplying the velocity to the cross sectional area of the meter.

Magnetic Flow Meters

Magnetic flow meters use Faraday's law of electromagnetic induction to determine the velocity of a liquid flowing in a pipe. Magnetic flow meters require a conductive product to operate. A magnetic field is generated and channeled into the liquid flowing through the pipe. Flow of a conductive liquid through the magnetic field generates a voltage

sensed by electrodes, which is proportional to the fluid velocity as shown in figure 1. The transmitter processes the voltage to determine liquid flow. In earlier days, these meters produced only an AC waveform (sinusoidal) and were subject to a number of influences that affected measurement quality including stray voltages in the process liquid, and electromagnetic voltage potential between the electrode and process fluid. As a result, the meter would drift and require a zero adjustment to compensate for these influences. Manufacturers have since implemented a DC waveform by turning the electromagnetic field on and off, producing a square wave. When the signal is on, it measures both the flow and process noise. When it is off, it measures only the noise, which is then subtracted from the overall output, eliminating zero adjustments and improving the performance of the meter. They will not measure non-conductive fluids such as natural gas or steam, but are an ideal solution for measuring water.

One disadvantage is magnetic flow meters have historically been limited to flange ratings of 300 ANSI due to material design. Their turn down capability is high, they create no pressure drop across the meter body and sizes range from 1/10" to more than 54 inches. Accuracy ranges from 0.2% of reading to 0.5% and the required up and downstream pipe diameters are 5 and 2. They are capable of measuring high concentration slurries with 165 Hz sensors and provide diagnostics to determine coating of the electrodes. Flow conditioners are not required. Magnetic flow meter sales continue to outpace all other flow metering technologies and are considered the number one selling flow meter in the world, primarily for water and wastewater applications.

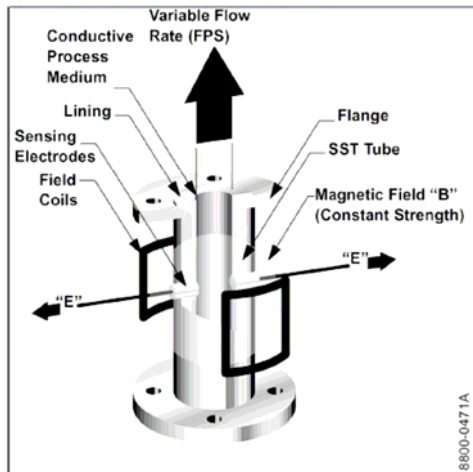


Figure 1

Vortex Shedding Meters

In the case of a vortex meter, the bluff body is the shedder bar, typically shaped like a square, rectangle, T or trapezoid as shown in Figure 1, and is submerged in a flowing fluid. As the fluid passes the bluff body, alternating whirl vortices are generated in the backward stream referred to as a Karman vortex street and illustrated in Figure 2. Another example of this is wind blowing across a flagpole causing the flag to flutter. The vortex shedding phenomenon is caused by pressure or velocities fluctuations on either side of the bluff body. Frequency detection can be accomplished by using different techniques including piezoelectric, differential pressure or capacitance, and is directly proportional to the flowing velocity and demonstrated with the following formula:

$$\text{Vortex frequency (f)} = \frac{\text{Strouhal number (St)} \times \text{Flow velocity (v)}}{\text{Vortex shedder width (d)}}$$

Strouhal number is defined as the ratio between the vortex interval and vortex shedder width. In most cases, a vortex interval is approximately 6 times the vortex shedder width while the Strouhal number is its reciprocal value equal to 0.17. The Strouhal number remains constant when Reynolds number (Re) is within a certain range. Reynolds number is defined as the relationship between fluid velocity, viscosity, and specific gravity.

Testing has shown that linearity, low Reynolds number limitation, and sensitivity to velocity profile can vary with bluff body shape and size. For the majority of manufacturers, the Strouhal number (St) is constant when Reynolds number (Re) is between 20000 and 7000000. Therefore, as long as Re. falls within this range, the vortex frequency is not affected by change in fluid viscosity, density, temperature or pressure, unlike many other meter technologies.

Advanced processing algorithms and adaptive noise suppression practically eliminate noise and vibration superimposed on the measuring signal making standard accuracies of 1.0% for gas and 0.75% for liquids easily attainable. Meter sizes range from 1/2" to 16", and require upstream pipe diameters ranging from only 10 – 40, depending on the disturbance and manufacturer without flow conditioning. Vortex meters are versatile, provide up to 30:1 turn down ratios, and are capable of withstanding product viscosities as high as 30 cP, or as low as 0.01 cP for high temperature, high quality steam. Permanent pressure loss is low when compared to an orifice plate. Flow conditioners are recommended for custody transfer applications. Some manufacturers offer multivariable options including temperature and pressure outputs for inferred mass flow rate, and reducer style meters for easily retrofitting existing

pipng. Caution is advised in continuous on/off applications, as the meter will not detect flow below 5000 Re which would be equivalent to its minimum detectable flow rate.

- The American Petroleum Institute currently has published a draft copy of Chapter 5, Section 8, titled “ Vortex Shedding Flow Meter For Measurement of Hydrocarbon Fluids”.
- Measurement Canada Provisional Specification PS-G-07 Rev 1 for the custody transfer of Natural gas.

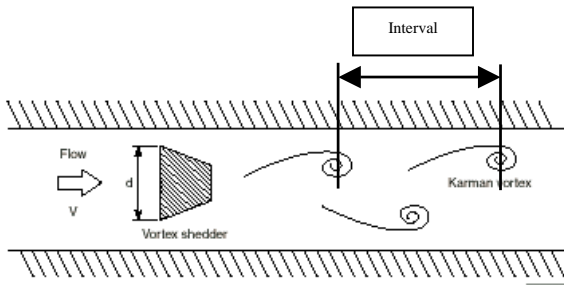


Figure 2

Ultrasonic Flow Meters

There are two primary principles for ultrasonic meters, transit time measurement and Doppler effect. The propagation velocity of a sound wave in a moving fluid depends on the fluid velocity, and is referred to as transit time measurement. If a sound wave is reflected from a moving object, such as bubbles, particles, and eddies in the flow stream a frequency shift occurs. This frequency shift is the Doppler effect, and the difference can be used to determine flow in a pipe. At no flow conditions, the transmitted energy and the reflected energy are theoretically the same. However, under flowing conditions, there will be a difference in signals due to the Doppler effect which relates how sound is perceived when reflected from objects in motion. The frequency difference between the transmitted energy and the reflected ultrasonic signal increases linearly as velocity increases. Performance can suffer if the process medium (moving objects) is not repeatable, and due to the non-reflective nature of many hydrocarbon processes, this method is not always practical. Transit time gas ultrasonic meters have been used successfully in custody transfer applications for years. A single path meter will use one set of transducers, both receive and transmit ultrasonic pulses. Multi-path meters will use multiple sets of transducers. When gas is flowing in a pipe, a

pulse traveling against the steam will use more time to reach the opposite transducer than a pulse traveling with the flow. This time difference is used to calculate the velocity of the flowing medium by the formula illustrated in Figure 3. Ultrasonic flow meters are bi-directional and are unaffected by changing gas composition, viscosity, temperature, and / or (gas) pressure. There are viscosity limitations for liquid meters and the manufacturer should be consulted. In-line meter sizes range from 2” to 36”, up and down stream pipe diameter requirements are 10 and 5 with flow conditioners, which are recommended for custody transfer measurement. Pressure loss is negligible, and turn down ratios are as high as 100:1. Uncalibrated meter accuracies range from over 2% to 0.5% depending on the number of paths. Expect 0.2% for a properly calibrated meter run. Some manufacturers are more susceptible to ultrasonic noise generated by control valves both upstream and downstream. A minimum number of pipe diameters, and 90 degree elbows with “T” configurations should be included in the piping design layout.

- The American Gas association published AGA Report No. 9 titled “Measurement of Gas by Multipath Ultrasonic Meters”.
- The American Petroleum Institute published Chapter 5, Section 8 titled “Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters using Transit Time Technology”.

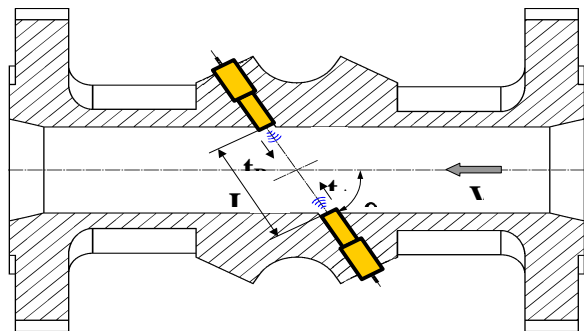


Figure 3

$$v_{Pfad} = \frac{L}{2 \cdot \cos \alpha} \left(\frac{1}{t_{AB}} - \frac{1}{t_{BA}} \right)$$



Coriolis Flow Meters

Coriolis forces, named for French mathematician Gustave Coriolis (1792-1843), are generated whenever a mass in a rotating body moves relative to that body, in a direction toward and away from the axis of rotation. Coriolis flow meters often contain one or more vibrating measuring tubes in the form of a “U” or straight tube design. The tubes are forced to resonate at a specific frequency that is altered by the coriolis forces of a flowing medium. The fluid to be measured flows through the tubes and accelerates as it reaches the excitation driver, or maximum vibration point. Upon leaving that point, it decelerates, causing the tubes to twist. The amount of twisting is detected by electromechanical pick up coils and is directly proportional to mass flow.



In Canada, volumetric measurement is still considered the standard. Converting from mass to volumetric requires a root mean square calculation of all error sources. Since volume is equal to mass divided by the density, that calculation should include the zero point stability factor, base meter accuracy, and density accuracy. Tube life expectancy is high providing velocities are kept within reason and the process conditions aren't overly harsh.

The down side to coriolis technology is that their capital cost is generally higher than other metering technologies and, depending on the manufacturer, they are limited to 6" line sizes. The large majorities are used in line sizes of 2" or less. A further consideration is pressure drop. With energy prices soaring, increased pumping costs to accommodate pressure drop can add up over time. Often more than one meter size is an option, and with less pressure drop the trade off is usually accuracy. Manufacturers publish 100:1 turn down ratios, but as with most metering technologies, performance does degrade at the low end of the meter factor curve limiting you to a more realistic 20:1 to maintain custody transfer accuracy. It's been noted that aerated liquids are among the top three non-hardware application issues for this technology.

Several manufacturers claim to handle two phase flow which is, for the most part, accomplished by a setting in the transmitter electronics that disables the output of the meter when the slug is detected. Process conditions such as this will not harm the meter, but this is not a recommended practice for custody transfer or billing purposes, and not something that should be considered over proper engineering design. Furthermore, the dynamic response of coriolis meters has been proven to be

slow when compared to other technologies due to the signal processing and physical characteristics of the meter itself. This can be an issue for process control where a fast response time may be necessary and when proving with a small volume prover. To overcome this, multiple proving passes may be required to establish a proper meter factor.

Coriolis flow meters are fast becoming one of the most popular metering technologies. There are essentially no moving parts, they provide a density output, uncertainty levels are in the 0.1% range for mass flow of liquid, 0.5% for natural gas, and repeatability is generally 0.05%.

- The American Gas Association published AGA Report number 11, "Measurement of Natural Gas by Coriolis Meter".
- API published two documents titled "Measurement of Crude Oil by Coriolis Meters" and "Measurement of Single Phase, Intermediate, and Finished Hydrocarbon Fluids by Coriolis".

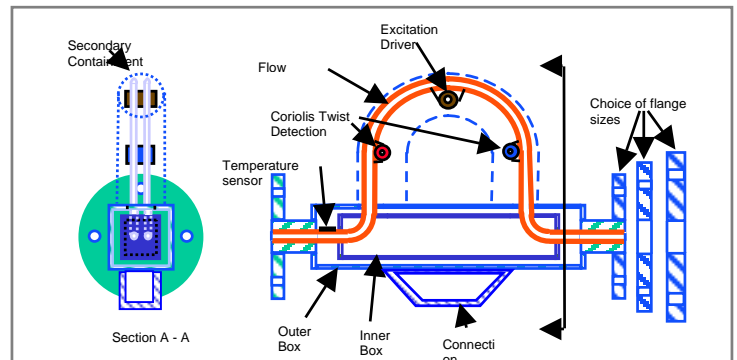


Figure 4

4.0 Accuracy: % Rate vs % Span or Full Scale

<p>Ex. 1 1% Full Scale Current Value + 1% of Full Scale Value 100 GPM +/- 1 GPM = 101-99 GPM or +/- 1 %</p>	<p>@ 100 GPM 1% Rate Current Value + 1% of Current Value 100 GPM +/- 1 GPM = 101-99 GPM or +/- 1 %</p>
<p>Ex. 2 1% of Full Scale Current Value + 1% of Full Scale 30 GPM +/- 1 GPM = 31-29 GPM or +/- 3.3%</p>	<p>@ 30 GPM 1% of Rate Current Value + 1% of Current Value 30 GPM +/- .3 GPM = 30.3-29.7 GPM or +/- 1 %</p>
<p>Ex. 3 1% of Full Scale Current Value + 1% of Full Scale 10 GPM +/- 1 GPM = 11-9 GPM or +/- 10%</p>	<p>@ 10 GPM 1% of Rate Current Value + 1% of Current Value 10 GPM +/- .1 GPM = 10.1 -9.9 GPM or +/- 1 %</p>

The above example demonstrates the importance of understanding the difference between % rate versus % span or full scale. A flow meter with an uncertainty expressed as full scale, has an accuracy curve that drops off sharply at the low end of the scale. This is common for differential pressure devices due to the square root extraction, which limits turn down.

5.0 Case Scenario 1

The following example is a crude oil application with a viscosity of 5.4 centistokes, SG of 0.855, process temperature range of 20 – 30 deg C, pressure range of 2770 to 9930 KPA, and flow range of 200 to 600 m3/hr. The first meter specification includes a positive displacement meter and the second includes a coriolis meter. To maintain an approximate 52 kPa pressure drop across each meter would require a total of 3 meters to achieve the same volumetric output, for a total of 156 kPa. Pressure drop requires increased pumping capacity, resulting in increased energy costs. Further more, this would require additional real estate, and valves both upstream and downstream. Both technologies produce uncertainties of 0.15% over a 10:1 turn down, however, one should consider the root mean square of all error sources to establish an overall uncertainty. The root mean square of the three coriolis meter errors assuming 0.15% for each after taking into account the base uncertainty, density calculation, and zero point stability equates to 0.67%. PD meters are not considered new technology meters, but do have their place in industry.

Primary Meter Selection Meter Specification

Process Data			
Process Fluid:	SYNCRUDE (SSB1)		
Specific Gravity:	0.855		
Viscosity:	5.4 Centistoke		
Flow Type Intermittent Flow			
Flow	Cubic Meters Per Hour	Temp Deg. C	Pressure KPA
Min:	200	Min: 20	
Opr:	475	Opr: 30	Opr: 2770
Max:	600	Max: 30	Max: 9930

Tag Number: AL2-FT-438(Typical)
 Meter: BiRotor (P-Style)
 Model: HC315ABAAAABCAAA
 Meter Flow Range: 79.5 TO 794 Cubic Meters Per Hour
 Temperature Range: -29 °C to 66 °C
 Max. Pressure: 10204 KPA MWP @30 °C
 Connections: 12", 600 ANSI / 10204 KPA MWP @38 °C
 Connection Type: Standard, 125 - 250 AARH
 Repeatability: ± 0.05%
 Accuracy: ± 0.15%
 Pressure Drop: 52 KPA @ 600 Cubic Meters Per Hour
 33 KPA @ 475 Cubic Meters Per Hour

Customer :

Tag Nr. :

Medium : Crude oil
 Density : 0.855 Sp.Gr Temperature : 20 Deg. C
 Viscosity : 5.4 cP Pressure : 9900 kPa

Proposed Sensor Size : **RCCS/T39/IR**

	Flow Rate m3/h	Accuracy (% of M.V.)	Pressure Drop (kPa)	Velocity (m/s)	Reynolds Number
100%	200	0.11	54	11.607	101447.16
90%	180	0.11	45	10.446	91302.44
80%	160	0.11	36	9.286	81157.73
70%	140	0.11	29	8.125	71013.01
60%	120	0.11	22	6.964	60868.30
50%	100	0.12	16	5.804	50723.58
40%	80	0.12	11	4.643	40578.86
30%	60	0.13	6	3.482	30434.15
20%	40	0.14	3	2.321	20289.43
10%	20	0.18	1	1.161	10144.72

6.0 Case Scenario 2

The following example is a natural gas measurement application comparing vortex, coriolis, and ultrasonic technology. The first diagram is a vortex sizing program and the second comes from an ultrasonic sizing program. With an SG of 0.7, viscosity of 0.0117 cP, compressibility of 0.996, temperature range from 10 to 20 deg C, pressure range from 3300 to 4600 kPa, and flow rate from 25 to 50 million standard cubic feet per day. The vortex sizing program below demonstrates how a 4" meter is preferred but the velocity through the meter is 218 ft/s, well beyond API recommended practice. The right solution if using a vortex is to use a 6" or 8" line size and a reducer style meter to keep velocities at recommended levels throughout the piping system. Notice the minimum flow and maximum flow rates (Qmin and Qmax), as well as pressure drop created for each option at maximum flow. Qlin is the linear flow rate, which usually corresponds to Qmin for natural gas applications due to the higher Reynolds numbers. Turn down ratios range from 25:1 to 40:1. In this same scenario, a 6" coriolis meter would create 150 KPA pressure drop at a capital cost of approximately two times one 6" ultrasonic, and five times the cost of a vortex. Ultrasonic meters do not create a pressure drop, and do provide 0.2% uncertainties if flow calibrated over a 100:1 turn down.

The screenshot shows the 'digitalVEWFLD Sizing' software interface. It includes input fields for Customer, Tag #, Date (03/26/2006), Fluid (Nat. Gas), Fluid Name, and Version (DYF 9.03). The 'Flow Data' section has dropdowns for Flow (M Scf/day), Press (kPa gauge), and Temp (°C), with input fields for Maximum, Operating, and Minimum values. Below this are fields for Density (0.700), SG, Viscosity (0.0117 centipoise), and Compressibility (0.996). A 'Clear' button is present. The main table lists meter models (DY100, DY150, DY200, DY250, DY300, DY400) with columns for Size (in), Qmax (M Scf/day), Qlin, Qmin, Pd, Recommended?, and Select Meter. The 'Selected Database' is C:\Program Files\YOKOGAWA\digitalVEWFLD sizing\Talisman fuel gas.ydb.

SP.GR. GAS	0.7		73.5948	FT/SEC AVG. VELOCITY	50.18
Q FLOW MMSCF/D	50	See Note 1			34,722
T TEMP Deg F.	65		2.46304	GAS LB/CU.FT.	2,083,333
D.I.D. OF PIPE	5.59	ID Inches			50,000,000
P PRESS PSIG	667	PSIG	95.58	Feet/Second MAXIMUM VELOCITY RECOMM	
VELOCITY CONSTANT	150	See Note 2		Reynolds # per GPA =	10,739,753
COMPRESSIBILITY	0.9960	1 OR LESS (PER FOLLOWING TABLE IF UNKNOWN)			
Dynamic Viscosity Cp	0.0117				

Flow Meter Selection Guide

What accuracy do you require? _____ Electrical Classification _____

Local indicator yes/no? _____ Meter output required (pulse / analogue / serial) _____

What are your piping considerations? New _____ Existing _____

Connection type (flanged / threaded / wafer) _____

What pressure drop can you accept through the meter? _____

What do you want to meter?

Steam _____	Condensate _____	Tower Water _____
Fuel Oil (grade) _____	Chilled Water _____	Natural Gas _____
Heating Hot Water _____	Domestic Water _____	Other _____

Other data required for selection:

Pressure:	Min. _____	Max. _____	Normal _____
Temperature:	Min. _____	Max. _____	Normal _____
Viscosity:	Min. _____	Max. _____	Normal _____
Flow Rate:	Min. _____	Max. _____	Normal _____
Pipe Size:	Min. _____	Max. _____	Normal _____
Density:	Min. _____	Max. _____	Normal _____
Specific Gravity cP:	Min. _____	Max. _____	Normal _____

Is this a Custody Transfer application? _____

(By definition - Custody Transfer measurement provides quantity and quality information used for the physical and fiscal documentation of a change in ownership and/or a change in responsibility in commodities)

Is Measurement Canada approval required? _____

Additional Comments _____

5.0 References

1. Yokogawa Corporation of America – Vortex Meter General Specifications 01F06A00-01E and 01F02B04-00E.
2. American Petroleum Institute – Measurement of Fluid Flow in Pipes Using Vortex Flow Meters, ASME/ANSI MFC-6M-1987.
3. Measurement Canada – Notice of Approval AG-0395 Rev 1.
4. Flow Measurement Engineering Handbook – R.W. Miller.
5. Flow Measurement – 2nd Edition – D.W. Spitzer.