PRINCIPLES OF OPERATION FOR ULTRASONIC GAS FLOW METERS

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ABSTRACT

This paper discusses fundamental issues relative to ultrasonic gas flow meters used for measurement of natural gas. A basic review of an ultrasonic meter's operation is presented to understand the typical operation of today's Ultrasonic Gas Flow Meter (USM). The USM's diagnostic data, in conjunction with gas composition, pressure and temperature, will be reviewed to show how this technology provides diagnostic benefits beyond that of other primary measurement devices. The basic requirements for obtaining good meter performance, when installed in the field, will be discussed with test results. Finally, recommendations for installation will be provided, including an example of a good piping design.

INTRODUCTION

During the past several years, the use of ultrasonic flow meters for natural gas custody transfer applications has grown significantly. The publication of AGA Report No. 9, *Measurement of Gas by Multipath Ultrasonic Meters* [Ref 1] in June 1998, has further accelerated the installation of ultrasonic flow meters (USMs). Today virtually every transmission and many distribution companies are using this technology fiscal or for operational applications.

Since the mid-1990s the installed base of USMs has grown by approximately 50% per year. There are many reasons why ultrasonic metering is enjoying such healthy sales. Some of the benefits of this technology include the following:

- **Accuracy:** Can be calibrated to <0.1%.
- **Large Turndown:** Typically >50:1.
- **Naturally Bi-directional:** Measures volumes in both directions with comparable performance.
- **Tolerant of Wet Gas**: Important for production applications.
- **Non-Intrusive:** No pressure drop.
- **Low Maintenance:** No moving parts means reduced maintenance.
- **Fault Tolerance:** Meters remain relatively accurate even if sensor(s) should fail.
- **Integral Diagnostics:** Data for determining a meter's health is readily available.

It is clear that there are many benefits to using USMs. Although the first several benefits are important, the most significant may turn out to be the ability to diagnose the meter's health. The primary purpose of this paper is to discuss basic gas ultrasonic meter operation, diagnostics, review the fundamentals of field maintenance, discuss some test results and provide the reader with an examples of good and not-so-good piping designs.

ULTRASONIC METER BASICS

Before looking at the main topic of integral diagnostics, it is important to review the basics of ultrasonic transit time flow measurement. In order to diagnose any device, a relatively thorough understanding is generally required. If the technician doesn't understand the basics of operation when performing maintenance, at best they can only be considered a "parts changer." In today's world of increasingly complex devices, and productivity demands on everyone, companies can no longer afford this type of service.

The basic operation of an ultrasonic meter is relatively simple. Consider the meter design shown in Figure 1. Even though there are several designs of ultrasonic meters on the market today, the principle of operation remains the same.

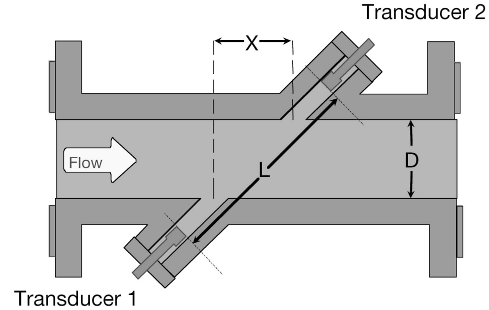


FIGURE 1. Ultrasonic Flow Meter

Ultrasonic meters are velocity meters by nature. That is, they measure the velocity of the gas within the meter body. By knowing the velocity and the cross-sectional area, uncorrected volume can be computed. Let us review the equations needed to compute flow.

The transit time (T_{12}) of an ultrasonic signal traveling with the flow is measured from Transducer 1 to Transducer 2. When this measurement is completed, the transit time (T_{21}) of an ultrasonic signal traveling against the flow is measured (from Transducer 2 to Transducer 1). The transit time of the signal traveling with the flow will be less than that of the signal traveling against the flow due to the velocity of the gas within the meter.

Let's review the basic equations needed to compute volume. Assume *L* and *X* are the direct and lateral (along the pipe axis and in the flowing gas) distances between the two transducers, *C* is the Speed of Sound (SOS) of the gas, *V* the gas velocity, and T_{12} and T_{21} are transit times in each direction. The following two equations would then apply for each path.

$$T_{12} = \frac{L}{C + V \cdot \frac{X}{L}} \qquad (1)$$

and

$$T_{21} = \frac{L}{C - V \cdot \frac{X}{L}} \qquad (2)$$

Solving for gas velocity yields the following:

$$V = \frac{L^2}{2X}\left(\frac{T_{21} - T_{12}}{T_{21} \cdot T_{12}}\right) \qquad (3)$$

Solving for the speed of sound (*C*) in the meter yields the following equation:

$$C = \frac{L}{2}\left(\frac{T_{21} - T_{12}}{T_{21} \cdot T_{12}}\right) \qquad (4)$$

Thus, by measuring dimensions *X* & *L*, and transit times T_{12} & T_{21}, we can also compute the gas velocity and speed of sound (SOS) along each path. The speed of sound for each path will be discussed later and shown to be a very useful parameter in verifying good overall meter performance.

The average transit time, with no gas flowing, is a function of meter size and the speed of sound through the gas (pressure, temperature and gas composition). Consider a 12-inch meter for this example. Typical transit times, in each direction, are on the order of one millisecond (and equal) when there is no flow. The *difference* in transit time during periods of flow, however, is significantly less, and is on the order of several nanoseconds (at low flow rates). Thus, accurate measurement of the transit times is critical if an ultrasonic meter is to meet performance criteria established in AGA Report No. 9.

It is interesting to note in Equation (3) that gas velocity is independent of speed of sound, and to compute speed of sound (Equation (4)), gas velocity is not required. This is true because the transit time measurements T_{12} and T_{21} are measured within a few milliseconds of each other, and gas composition does not change significantly during this time. Also, note the simplicity of Equations (3) and (4). Only the dimensions *X* and *L*, and the transit times T_{12} and T_{21}, are required to yield both the gas velocity and speed of sound along a path.

These equations look relatively simple, and they are. The primary difference between computing gas velocity and speed of sound is the *difference* in transit times is used for computing velocity, where as the *sum* of the transit times is used for computing speed of sound.

Unfortunately, determining the correct flow rate within the meter is a bit more difficult than it appears. The velocity shown in Equation (3) refers to the velocity of each individual path. The velocity needed for computing volume flow rate, also know as bulk mean velocity, is the average gas velocity across the meter's area. In the pipeline, gas velocity profiles are not always uniform, and often there is some swirl and asymmetrical flow profile within the meter. This makes computing the average velocity a bit more challenging.

Meter manufactures have differing methodologies for computing this average velocity. Some derive the answer by using proprietary algorithms. Others rely on a design that does not require "hidden" computations. Regardless of how the meter determines the bulk average velocity, the following equation is used to compute the uncorrected flow rate.

$$Q = \overline{V} * A \qquad (5)$$

This output (*Q*) is actually a flow rate based on volume-per-hour, and is used to provide input to the flow computer. *A* is the cross-sectional area of the meter.

In summary, some key points to keep in mind about the operation of an ultrasonic meter are:

- The measurement of transit time, both upstream and downstream, is the primary function of the electronics.
- All path velocities are averaged to provide a "bulk mean" velocity that is used to compute the meter's output (*Q*).
- Because the electronics can determine which transit time is longer (T_{21} or T_{12}), the meter can determine direction of flow.
- Speed of sound is computed from the same measurements as gas velocity (*X* is not required).

Transit time is the most significant aspect of the meter's operation, and all other inputs to determine gas velocity and speed of sound are essentially fixed geometric (programmed) constants.

INTEGRAL DIAGNOSTICS

One of the principal attributes of modern ultrasonic meters is their ability to monitor their own health, and to diagnose any problems that may occur. Multipath meters are unique in this regard, as they can compare certain measurements between different paths, as well as checking each path individually.

Measures that can be used in this online "health checking" can be classed as either internal or external diagnostics. Internal diagnostics are those indicators derived only from internal measurements of the meter. External diagnostics are those methods in which measurements from the meter are combined with parameters derived from independent sources to detect and identify fault conditions. Some of the common internal meter diagnostics used are as follows.

Gain

One of the simplest indicators of a meter's health is the presence of strong signals on all paths. Today's multipath USMs have automatic gain control on all receiver channels. Any increase in gain on any channel indicates a weaker signal, perhaps due to transducer deterioration, fouling of the transducer ports, or liquids in the line. However, caution must be exercised to account for other factors that affect signal strength, such as pressure and flow velocity.

Gain numbers vary from manufacturer to manufacturer. Thus, recommendations may also differ. However, regardless of design or methodology for reporting gain, it is important to obtain readings on all paths under somewhat similar conditions. The significant conditions to duplicate are metering pressure and gas flow rate.

Gain readings are generally proportional to metering pressure (and to a much lesser extent, temperature). That is, when pressure increases, the amount of gain (amplification) required is reduced. If an initial gain reading were taken at 600 psig, when the meter was placed into service, and subsequent readings taken at 900 psig, one would expect to see a change. This change in reading (assuming gain values are linear, not in dB) would decrease by the ratio of pressures (600/900). Understanding that pressure affects gain readings helps guard against making the false assumption something is wrong.

Fortunately, most applications do not experience a significant variation in metering pressure. If pressure does vary, the observed gain value can be adjusted relatively easily to allow for comparison with baseline values. This method of adjustment varies with manufacturer, so no discussion will be incorporated here.

Gas velocity can also impact the gain level for each path. As the gas velocity increases, the increased turbulence of the gas causes an increase in signal attenuation. This reduction in signal strength will be seen immediately by increased gain readings. These increases are generally small compared to the amount of gain required. Typical increases might be on the order of 10-50%, depending upon meter size and design. Thus, it is always better to "baseline" gain readings when gas velocities are below 30 fps. Using velocities in excess may provide good results, but it is safe to say that lower velocities provide more consistent, repeatable results.

So, what else causes reductions in signal strength (increased gain)? There are many sources other than gas velocity and pressure. For instance, contamination of the transducers (buildup of material on the face) will attenuate the transmitted (and received) signals. One might assume that this buildup would cause the meter to fail (inability to receive a pulse). However, this is not generally the case. Even with excessive buildup of more than 0.050 of an inch of an oily, greasy, and/or gritty substance, today's USMs will continue to operate.

One question often asked is "What impact on transit time accuracy could be attributed to transducer face contamination?" It is true the speed of sound will be different through the contaminated area when compared to the gas. Let's assume a build-up is 0.025 of an inch on each face, and the path length is 16 inches. Also assume the speed of sound through the contamination is twice that of the typical gas application (2,600 fps vs. 1,300 fps). With no buildup on the transducer, and at zero flow, the average transit time would be 1.025641 milliseconds. With buildup the average transit time would be 1.024038 milliseconds, or a difference of 0.16%. This would be reflected in the meter's reported speed of sound (more on that later). However, it is the difference in transit times that determines gas velocity (thus volume). This is the affect that needs to be quantified.

Maybe the easiest way to analyze this is assume the transit time measurements in both directions are reduced by 0.16% (from the previous example). Remembering in Equation (3) that gas velocity is proportional to a constant ($L^2/2X$) multiplied by the difference in transit times, all divided by the product of transit times. The decrease in transit times will occur for both directions, and this effect appears to be negated in the numerator. That is, the Dt will remain the same. However, the error in both T_{12} and T_{21} will cause the denominator value to decrease, thus producing an error that is twice the percentage of transit time (0.16%), or 0.32%. Thus, the meter's output will increase by 0.32%. *However, this amount of buildup is abnormal, and not typical of most meter installations.*

Concluding the discussion on gain readings, USMs all have more than adequate amplification (gain) to overcome even the most severe reductions in signal strength. The amount of buildup required to fail today's high-performance transducers and electronics generally exceeds pipeline operational conditions. Periodic monitoring of this parameter, however, will help insure good performance throughout the life of the meter.

Metering accuracy (differences in transit time velocity computation) can be affected, but only when significant buildup of contamination occurs.

Signal Quality

This expression is often referred to as performance (but should not be confused with meter accuracy). All ultrasonic meter designs send multiple pulses across the meter to another transducer before updating the output. Ideally, all the pulses sent would be received and used. However, in the real world, sometimes the signal is distorted, too weak, or otherwise the received pulse does not meet certain criteria established by the manufacturer. When this happens the electronics rejects the pulse rather than use something that might distort the results. The level of acceptance (or rejection) for each path is generally considered as a measure of performance, and is often referred to as signal quality. Meters provide a value describing how good signal detection is for each ultrasonic path.

As mentioned above, there are several reasons why pulses can be rejected. Additional causes may include extraneous ultrasonic noise in the same region the transducer operates, distorted waveforms caused by excessive gas velocity, and to some degree, contamination on the face of the transducer.

Typically, the value of acceptance for each path, under normal operating conditions, will be 100%. As gas velocity increases to near the meter's rating, this percentage may begin to decrease. Depending upon design, this percentage may decrease to below 50%. Generally, this reduction in performance will have little impact on meter accuracy. However, if the percentage of accepted pulses is this low, it is safe to say the meter is not operating at top performance, and investigation may be warranted (assuming the meter isn't operating at 110+% of rated capacity).

Concluding the discussion on performance, this parameter should be monitored periodically as poor performance on a path may be an indication of possible impending failure. Lower than expected performance can be caused by several factors. Besides excessive gas velocity, contamination on the transducer face and excessive extraneous ultrasonic noise can reduce signal quality. However, by monitoring gains, this condition can be easily identified before it becomes a problem.

Signal-to-Noise Ratio

This parameter is another variable that provides information valuable in verifying the meter's health, or alert of possible impending problems. Each transducer is capable of receiving noise information from extraneous sources (rather than its mated transducer). In the interval between receiving pulses, meters monitor this noise to provide an indication of the "background" noise. This noise can be in the same ultrasonic frequency spectrum as that transmitted from the transducer itself.

Noise levels can become excessive if a control valve is placed too close and the pressure differential is too high. In this scenario the meter may have difficulty in differentiating the signal from the noise. By monitoring the level of noise, when no pulse is anticipated, the meter can provide information to the user, warning that meter performance (signal quality) may become reduced. In extreme cases, noise from control valves can "swamp" the signal to the point that the meter becomes inoperative.

All meters can handle some degree of noise created from this condition. Some USM designs can handle more than others can. The important thing to remember is the best time to deal with control valve noise is during the design. Today's technology has improved significantly in dealing with extraneous noise. Reducing it in piping design is always the best choice (more on this later).

Other sources can cause reduced signal to noise values. Typically they are poor grounding, bad electrical connections between electronics and transducers, extraneous EMI and RFI, cathodic protection interference, transducer contamination and in some instances, the meter's electronic components. However, the major reason for decreased signal to noise ratios remains pressure drop from flow control or pressure reducing valves.

Concluding this discussion on signal to noise, the most important thing to remember is high-pressure drop (generally in excess of 200 psig) across a control valve can cause interference with the meter's operation. If the noise is isolated to a transducer or pair of transducers, the cause is generally not control valve related. Here probable causes are poor component connections or a potential failing component. Control valve noise usually causes lower signal to noise levels on the transducers that face the noise source (all would be affected).

Velocity Profile

Monitoring the velocity profile is possibly one of the most overlooked features of today's ultrasonic meter. It can provide many clues as to the condition of the metering system, not just as a monitor of the meter. AGA Report No. 9 requires a multipath meter to provide individual path velocities. As mentioned previously, the output used by the flow computer is an average of these individual readings.

Once the USM is placed in service, it is important to collect a baseline (log file) of the meter. That is, record the path velocities over some reasonable operating range, if possible. Good meter station designs produce a relatively uniform velocity profile within the meter. The baseline log file may be helpful in the event the meter's performance is questioned later.

Many customers choose to use a "high performance flow conditioner" with their meter. This conditioner is intended to isolate any upstream piping effects on gas profile. In reality, they don't totally isolate the disturbance, but do provide a reasonably repeatable profile. The important issue here is the velocity profile is relatively repeatable. Once a baseline has been established, should something happen to the flow conditioner, it can be identified quickly by comparing path velocities with the baseline. Many things can happen to impact the original velocity profile. Changes can be caused by such things as:

- partial blockage of the flow conditioner,
- damage to the flow conditioner,
- or upstream piping affects, such as a change in a valve position.

Of course, something could have also occurred with the meter to cause a significant profile change. Generally speaking, this is unlikely as all components are securely mounted. However, the velocity of a given path could be affected by other problems. When considering that only *X* and *L* dimensions, and transit times, impact path velocity, it is relatively easy to eliminate these. If a problem develops within the meter that impacts only one or more paths, other performance indicators, such as gain, path performance, and speed of sound will also be indicating problems.

One of the major benefits of analyzing path velocities is the ability to determine if the meter assembly is becoming contaminated with any pipeline debris. Surface roughness changes in the upstream piping will change the velocity profile the meter sees. A profile change can be observed by analyzing the different path velocities relative to the meter's reported average. Typically the velocity profile becomes more "pointed" as the surface finish becomes rougher. This is a very important feature since contamination on the inside of a meter will impact the meter's accuracy [Ref 2].

Different manufacturers utilize different path velocity integration techniques. The ability to monitor profile changes, and thus predict the significance of this effect, may vary by design. Thus, it may not be possible for all USM designs to provide this diagnostic information.

Concluding this discussion on path velocities, most good installations produce somewhat symmetrical velocities within the meter. Comparing each path's velocity with the average, and sometimes to other paths, depending upon the USM design, can give the user confidence the profile has not significantly changed. Today's USM can handle some relatively high levels of asymmetry within the meter. It should *not* be assumed that the meter's accuracy is significantly impacted just because the velocity profile has changed. It is usually an indication, however, that something within the meter set, other than the meter itself, is probably causing the effect. Careful review of other diagnostic parameters can determine if the meter is at fault, or not. Identifying changes in path velocities are very helpful in determining if contamination has occurred on the inside of the piping. Contamination may have an impact on the meter's accuracy.

Speed Of Sound

Probably the most discussed and used diagnostic tool is the meter's speed of sound (SOS). The reader may recall that speed of sound is basically the sum of the transit times divided by their product, all then multiplied by the path length (Equation (4)). As was discussed earlier, the primary measurement an ultrasonic meter performs to determine velocity is transit time. If the transit time measurement is incorrect, the meter's output will be incorrect, and so will the speed of sound. Thus, it is important to periodically verify that the meter's reported speed of sound is within some reasonable agreement to an independently computed value.

Modern USMs use high frequency clocks to accurately perform transit time measurements. In a typical 12-inch meter, the average transit time may be on the order of one millisecond. To obtain a perspective on this differential time, values start out in the 10's of nanoseconds and typically increase to maybe 100 microseconds at the highest velocities.

Obviously accurate meter performance requires consistent, repeatable transit time measurements. Comparing the SOS to computed values is one method of verifying this timing. This procedure would be considered an external diagnostic technique. Let's examine the affects (or uncertainties) on computing speed of sound in the field.

Pressure & Temperature Effects

The speed of sound in gas can be easily computed in the field. There are several programs used for this purpose. Most are based upon the equation of state provided in AGA Report No. 8, *Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases* [Ref 3]. When computing speed of sound, there is always some uncertainty associated with this operation. It is important to realize that the speed of sound is more sensitive to temperature and gas composition than pressure. For example, a one degree F error in temperature at 750 psig, with typical pipeline gas, can create an error of 0.13%, or about 1.7 fps. An error of five psig at 750 psig and 60 degrees F only contributes 0.01% error. Thus, it is very important to obtain accurate temperature information.

Knowing the temperature measurement error contributes significant error in computing SOS is important. However, if the temperature is in error by one degree F, a more significant question might be "what error is this causing in the volumetric measurement?" A quick calculation shows a one degree F error will cause the corrected volumetric calculation to be incorrect by 0.28%. Having a history of calculated SOS vs. measured may actually be a good "health check" on the stations temperature measurement!

Gas Composition Effects

Sensitivity to gas composition is a bit more difficult to quantify as there is an infinite number of sample analyses to draw from. Let's assume a typical Amarillo gas composition with about 90% methane. If the chromatograph were in error on methane by 0.5%, and the remaining components were normalized to account for this error, the resulting effect on speed of sound would be 0.03%. Thus, minor errors in gas composition, for relatively lean samples, may not contribute significantly to the uncertainty.

However, lets look at another example of a Gulf Coast gas with approximately 95% methane. Suppose the methane reading is low by 0.5%, and this time the propane reading was high by that amount, the error in computed speed of sound would be 0.67% (8.7 fps!). Certainly one could argue this may not be a "typical" error. There are many scenarios that can be discussed and each one would have a different effect on the result. The uncertainty that gas composition contributes to the speed of sound calculation remains the most elusive to quantify, and, depending upon gas composition, may prove to be the most significant.

A typical question is "what difference can be expected between that determined by the meter, and one computed by independent means?" It has been shown [Ref 4] that the expected uncertainties (two standard deviations) in speed of sound, for a typical pipeline gas operating below 1,480 psig, are:

- USM measurement: ± 0.17%
- Calculated (AGA 8): ± 0.12%

Since the USM's output is independent of the calculation process, a root-mean-square (RMS) method can be used to determine the system uncertainty. Thus, when using lean natural gas below 1,480 psig, it is expected that 95% of readings agree within 0.21% (or about 2.7 fps). Therefore, it may be somewhat unrealistic to assume the meter will agree within 1 fps under typical operating conditions.

Concluding this discussion on speed of sound, this "integral diagnostic" feature may be the most powerful tool for the technician. Using the meter's individual path speed of sound output, and comparing it to not only the computed values, but also comparing within the meter itself, is a very important maintenance tool. Caution should be taken when collecting the data to help minimize any uncertainty due to gas composition, pressure and temperature. Additionally, it is extremely important to obtain data only during periods of flow as temperature stratification can cause significant comparison errors. By developing a history of meter SOS, and comparing with computed values, it can also be used as a "health check" for the temperature measurement used to determine corrected volumes.

IMPORTANCE OF SOS VERIFICATION

As was discussed earlier, SOS verification helps insure the meter is operating correctly. However, what other changes in a meter can affect the reading? From the previous discussion on gain, buildup on the face of a transducer will affect the speed of sound. Thus, if a pair of transducers has a different value, when compared to the average (or to other paths, depending upon meter's design), this might be an indication of contamination.

One thing to remember is that the percent change in speed of sound, given the same buildup, will be greater for a smaller meter than a larger one. As path length increases from say 10 inches to 30 inches (or more), a buildup of 0.025 inches will affect the transit time less. By utilizing gain information with SOS data for a given path, it can be quickly determined if the change in SOS is due to contamination, or other causes.

Another benefit in monitoring path SOS is to verify proper identification of reception pulses. In the section on signal to noise, extraneous noise was noted to potentially interfere with normal meter operation. That is, if ultrasonic noise within the meter (caused by outside sources) becomes too great, meter performance will be impacted. As the noise level increases, there is the possibility that the circuit detecting the correct pulse will have difficulty. Good meter designs protect against this and reject received pulses that have increased uncertainty regarding their validity. If this scenario occurs, it is unlikely all paths will be affected simultaneously, and by the same amount. Monitoring variations in SOS from path to path will identify this problem and help insure the meter's health is satisfactory.

Typical Speed of Sound Field Results

This section provides actual data from two different meters. Figures 2 and 3 show trended vs. time. Data is shown for an eight-inch meter in Figure 2 [Ref 3]. It compares the average speed of sound over the four paths with the AGA 8 calculated value.

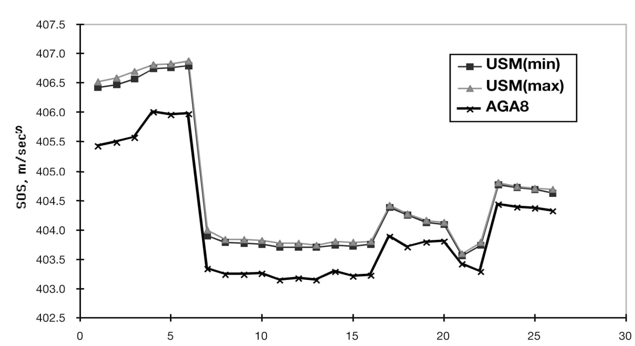


FIGURE 2. 8-INCH METER MEASURED VS. CALCULATED SOS

At each measurement point, ten successive values of the ultrasonic meter's SOS were logged. The two curves that show the minimum and maximum values in Figure 2 demonstrates repeatability in SOS measurements of better than 0.03%. The difference in the meter's speed of sound vs. computed values are also, for most points, less than 0.3%.

Figures 3 shows the AGA 8 calculated speed of sound trended against the individual SOS readings from the four paths. Note that in each case the agreement on all chords is roughly as expected (better than 0.3%). In the area where speed of sound deviations exceeded 0.3%, (Figure 3) low flow temperature stratification was likely the cause. In the event of significant contamination on one or more pairs of transducers, this graph would have shown the impact.

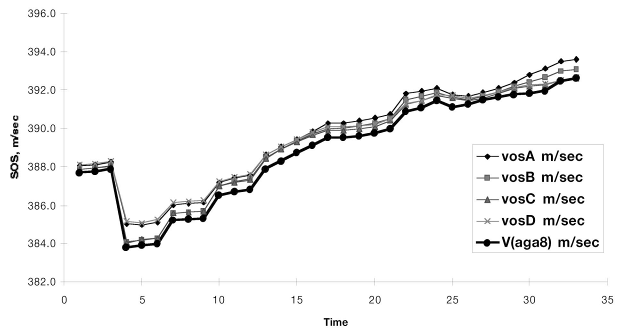


FIGURE 3. 10-inch Meter SOS with 4 Chords

Concluding this discussion on external calculations, the results demonstrate multi-path ultrasonic meters show good correlation between the computed speed of sound and the meter's reported speed of sound. Even though there are differences between computed and reported values, these remain relatively constant though out the test period. This also suggests that when performing an on-line comparison of speed of sound, an alarm limit of about ± 0.3% between the meter and computed values, as recommended earlier, is reasonable. However, as shown in Figure 3, for a short interval the error exceeded 0.3% (during periods of low (or no) flow and temperature stratification). Since this situation can occur in the field, safeguards should be implemented to insure gas velocity is above some minimum value, and for a specified time, before alarming occurs. Thus, the use of independent estimates of gas speed of sound, derived from an analysis of the gas composition, can be an effective method of understanding how well an ultrasonic meter is performing.

BASICS OF USM INSTALLATIONS

When installing ultrasonic flow meters, many factors should be taken into consideration to insure accurate and trouble-free performance. Before discussing these issues, let's review the basics of a good installation.

Basic Piping Issues

Ultrasonic meters require adhering to basic installation guidelines just as with any other technology. Primary metering elements, such as orifice and turbine, have adopted recommendations for installation long ago. These are provided through a variety of standards (API, AGA, etc.) to insure accurate performance (within some uncertainty guidelines) when installed. The reason for these guidelines is the meter's accuracy can be affected by profile distortions caused by upstream piping. One of the benefits of today's USM is that they can handle a variety of upstream piping designs with less impact on accuracy then other primary devices.

Installation effects have been studied in much more detail than ever before. This is due in part to the available technology needed for evaluation. Reducing uncertainty for pipeline companies has also become a higher priority today due to the increasing cost of natural gas. Let's look at a typical velocity profile downstream of a single elbow.

From this mathematical velocity profile model it is apparent the velocity profile at 10D from the elbow is far from being fully symmetrical. What isn't apparent in this model is the amount of swirl generated by the elbow. According to research work performed at Southwest Research Institute (SwRI) by Terry Grimley, it would take on the order of 100D for the profile to return to a fully symmetrical, fully developed, non-swirling velocity profile [Ref 5]. More complex upstream piping, such as two elbows out of plane, create even more non-symmetry and swirl than this model shows. Today's USM must handle profile distortion and swirl in order to be accurate and cost-effective. However, just as with orifice and turbine meters, installation guidelines should be followed.

In 1998 AGA released the Transmission Measurement Committee Report No. 9 entitled *Measurement of Gas by Multipath Ultrasonic Meters*. This document discusses many aspects and requirements for installation and use of ultrasonic meters. Section 7.2.2 specifically discuss the USMs required performance relative to a flow calibration. It states the manufacturer must "Recommend upstream and downstream piping configuration in minimum length – one without and flow conditioner and one with a flow conditioner - that will not create an additional flow rate measurement error of more than ±0.3% due to the installation configuration." In other words, assuming the meter were calibrated with ideal flow profile conditions, the manufacturer must then be able to recommend an installation which will not cause the meter's accuracy to deviate more than ±0.3% from the calibration once the meter is installed in the field.

During the past several years a significant amount of tests were conducted at SwRI in San Antonio, Texas to determine installation affects on USMs. Funding for these tests has come from the Gas Research Institute (GRI).

Much of the testing was directed at determining how much error is introduced in today's USMs when a variety of upstream installation conditions are present. This was presented in a report entitled *Ultrasonic Meter Installation Configuration Testing* at the 2000 AGA Operations Conference in Denver, Colorado. Following is an excerpt from this report that shows the impact of upstream effects on an ultrasonic meter.

Installation Effect:	One Elbow		Elbows Out		Elbows In	
Meter Orientation:	0°	90°	0°	90°	0°	90°
No Conditioner, 10D	**0.07**	**0.02**	0.53	**0.04**	**0.02**	**0.24**
No Conditioner, 20D	**0.13**	**0.11**	**0.05**	**0.10**	**0.11**	**0.12**
19-Tube Bundle	0.35	0.37	**0.13**	0.37	**0.15**	**0.22**
Flow Conditioner #1	**0.10**	**0.03**	**0.02**	**0.02**	**0.07**	**0.14**
Flow Conditioner #2	**0.15**	**0.13**	**0.23**	**0.30**	**0.03**	**0.04**
Flow Conditioner #3	**0.04**	**0.00**	**0.17**	**0.23**	0.36	0.41

Meets AGA 9	Doesn't meet AGA 9

Table No. 1 – GRI Installation Test Results

The preceding table presents metering accuracy results from a 4-path meter with a variety of upstream effects (single elbow, two elbows in plane and two elbows out of plane). Tests were conducted with no upstream flow conditioner and four brands of flow conditioners, all located at their manufactures recommended position. One thing to note is the 19-tube bundle did not perform very well. Also of importance is the meter met the AGA 9 installation requirement test producing less than ±0.3% shift with no flow conditioner when located a minimum of 20D from the upstream effect.

In conclusion, for basic piping issues, upstream piping does have an effect on the meter's performance. Many customers choose to use a flow conditioner in order to reduce potential upstream effects. The use of 19-tube bundles is not recommended by most manufacturers today as the results are not consistent and are generally not as good as with other flow conditioners. Flow conditioners are not always required. As can be seen in line two of the table, this meter passed the installation affects test with no flow conditioner when located 20D from the effect, and passed all but one test when located at 10D.

Other Piping Issues

One aspect to keep in mind when designing an ultrasonic meter station is the use of control valves (regulators). Ultrasonic meters rely on being able to communicate between transducers at frequencies in excess of 100 kHz. Control valves can generate ultrasonic noise in this region. How much depends upon several factors including the type of valve, flow rate and differential across the valve.

Manufacturers have different methods for dealing with control valve noise. Whenever an ultrasonic meter is used in conjunction with a control valve, the manufacturer should be contacted prior to design. Following is a diagram of meter set with a flow conditioner and control valve.

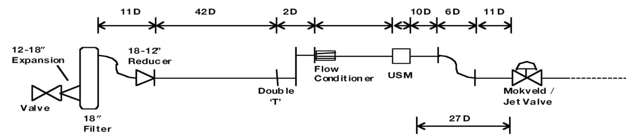
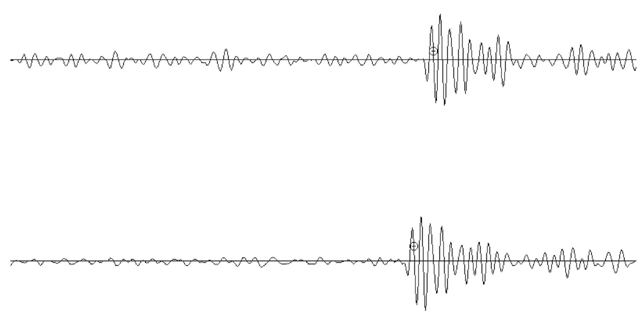


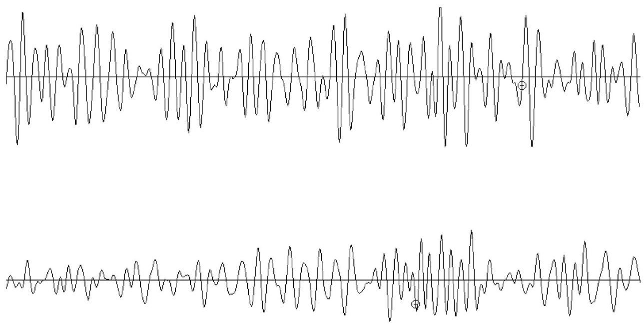
FIGURE 4. Poor USM Piping Diagram

In this design pressure reduction occurs at about 27D from the meter. There are two elbows between the meter and valve. At low flow rates this design would probably work fine. However, as the flow rate increases, so does the amount of energy generated by the pressure reduction. The amount of noise generated is roughly proportional to the square-root of the flow rate times the differential pressure. Thus, as flow rate (or differential pressure) increases, so will the amount of noise generated. At some higher flow rate the meter will be unable to identify the signal, and measurement will cease. Following are two sets of waveforms. The first is a typical signal received by a pair of transducers when there is no extraneous ultrasonic noise. The second is an example of a meter experiencing noise from a control valve. In order to continue operation, the meter must be able to handle this type of noise (Graph No. 2).



GRAPH NO. 1 – Typical USM Waveform

A better design would be to locate the meter further upstream (see Figure 6 following). By installing two tees between the meter and control valve, much of the ultrasonic noise is reflected back downstream, helping isolate the meter from the noise source. Also, in this design, the meter has been located more than 70D from the valve. Ultrasonic noise, just like audible sound, becomes attenuated the further you get from the source.



GRAPH NO. 2- USM Waveform With Valve Noise

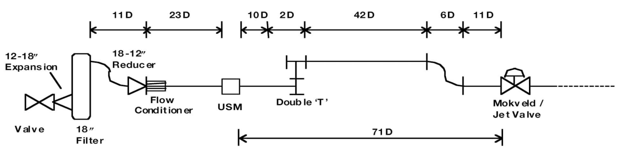


FIGURE 5 – Better USM Piping Diagram

In conclusion, control valves can create enough noise that will over-power the USMs signal. Control valves should be located away from the meter. Install the meter upstream of the control valve whenever possible as more noise propagates downstream than upstream. Also, with the higher pressure upstream, the USM will obtain a stronger signal from the transducers, making it easier to detect the signal when in the presence of noise. Tees between the meter and the control valve are more effective than elbows at reducing noise. (about twice the noise attenuation). Probably the most significant thing to remember is consult with the manufacturer during the design phase. Testing of USMs with control valve noise is ongoing with all manufacturers, and better methods of handling noise are constantly being developed. Some manufacturers have internal meter digital signal processing that can handle increased levels of control valve noise.

FLOW CALIBRATION BASICS

The primary use for USMs today is in custody measurement applications. As was discussed earlier, the introduction of AGA Report No. 9 has helped spur this growth. Section 5 (of AGA 9) discusses performance requirements, including flow calibration. It does not require meters be calibrated before use. However, paraphrasing, it does require ..“the manufacturer to provide sufficient test data confirming that each meter shall meet these requirements.” The basic accuracy requirement is that 12-inch and larger meters be within ±0.7%, and 10-inch and smaller meters to be within ±1.0%. Again, these maximum error values are “prior” to flow calibration.

Most customers feel their applications deserve, and require, less uncertainty than the minimum requirements of AGA 9. Thus, a for virtually all USM custody applications, users are flow calibrating their meters.

In a majority of applications today customers are using flow conditioners. USMs are designed to be installed without a flow conditioner. Part of the benefit of an ultrasonic meter is there is no pressure drop. However, many feel that using a “high performance” flow conditioner (not a 19-tube bundle) further enhances performance. Even though data exists to support some USMs perform quite well without flow conditioners, the added pressure drop and cost is often justified by assuming uncertainty is reduced. One thing that everyone does agree on is that if a flow conditioner is used with a meter, the entire system should be calibrated together. Most companies have standard designs for their meters. They typically specify piping upstream and downstream of the flow conditioner(s) and meter. Thus, USMs are typically calibrated with either 3 or 4 piping spools. Calibrating as a unit helps insure the accuracy of the meter, once installed in the field, is as close to the results provided by the lab as possible.

There are several flow calibration labs in North America that provide calibration services. Labs usually test meters throughout the range of operation. Once all the “as-found” data points have been determined, an adjustment factor is computed. The adjustment is uploaded to the meter and either one or two verification points are used to verify the “as-left” performance.

PERIODIC FLOW CALIBRATION

AGA 9 does not currently require an ultrasonic meter be re-calibrated. In the next update it is expected that all custody applications will require flow calibration. As USMs have no moving parts, and provide a variety of diagnostic information, many feel the performance of the meter can be field verified. That is, if the meter is operating correctly, its accuracy should not change, and if it does change, it can be detected. This, however, remains to be proven.

The use of USMs for custody began increasing rapidly in 1996. Thus, with less than 5 years of installed base, it is difficult to prove USMs don’t require re-calibration. Many companies are not certain as to whether or not they will retest their meters in the future. They are waiting for additional data to support their decision. Manufacturers are also trying to show the technology should not require re-calibration.

The benefits of flow calibrating USMs have been well documented over the past few years [Ref 6]. Not only does flow calibration reduce the meter’s uncertainty, it is often used to extend the rangeability of a meter to extremely low flow rates. This expanded rangeability can often permit one meter to have a flow range of greater than 100-1 and a measured accuracy on the order of ±0.1% (relative to the calibration facility). Flow calibration also has been used to validate a meter' performance when less than the full compliment of transducers is operating. This is beneficial for those times when a transducer is removed for inspection, but the meter must remain in service.

During the next several years many meters will require re-calibration in Canada. Their governmental agency, Measurement Canada, requires USMs be re-tested every 6 years. Many meters will be due for re-testing in 2003 and 2004. Once data is obtained from these tests, from random re-testing by customer, and long-term data from meters at calibration labs is analyzed, customers can better determine if they should re-calibrate their USMs in the future.

CONCLUSIONS

During the past several years ultrasonic meters have become one of the fastest growing new technologies in the natural gas arena. The popularity of these devices has increased because they provide significant value to the customer by reducing the cost of doing business. One of the most significant benefits is the reduction in maintenance over other technologies.

There are several factors that can be attributed to this increased usage. First, as there are no moving parts to wear out, reliability is increased. Since USMs create no differential pressure, any sudden over-range will not damage the meter. If the meter encounters excessive liquids, it may cease operation momentarily, but no physical damage will occur, and the meter will return to normal operation once the liquid has cleared. Most importantly, ultrasonic meters provide a significant amount of diagnostic information within their electronics. Most of an ultrasonic meter's diagnostic data is used to directly interpret its "health." Additional diagnostics can be performed by using external devices. This diagnostic data is available on a real-time basis and can be monitored and trended in many of today's remote terminal units (RTUs). USMs support remote access and monitoring in the event the RTU can't provide this feature. There are five commonly used diagnostic features being monitored today. These include speed of sound by path (and the meter's average value), path gain levels, path velocities, path performance values (percentage of accepted pulses), and signal to noise ratios. By utilizing this information, the user can help insure the proper meter operation.

Probably the most commonly used tools are path speed of sound and gains. Speed of sound is significant since it helps validate transit time measurement, and gains help verify clean transducer surfaces. When computing speed of sound in the field, care should be taken to collect data only during periods of flow in the pipeline as temperature gradients will distort comparison results. Additionally, as shown in one of the graphical examples, low-flow limits should be implemented to insure pipeline temperature is uniform and stable before comparing meter speed of sound with computed values from gas composition, pressure and temperature.

One significant benefit in performing online comparisons between the meter's speed of sound and a computed value is to provide a "health check" for the entire system. If a variation outside acceptable limits develops, the *probable cause* will be temperature, pressure, or gas composition measurement error rather than the USM. *<u>In this regard, the USM is actually providing a "health check" on the measurement system</u>!*

Monitoring path velocities is gaining in popularity daily. It has been shown that velocity information can help predict if the inside of a meter is becoming contaminated with pipeline buildup [Ref 2]. In the past it was believed that buildup inside of a meter would be detected by an increase in gains. However, recent analysis of meters has shown this may not be the case [Ref 2, 7 & 8]. Thus, path velocity information will probably remain as the single most important tool for identifying if a meter is dirty internally.

Control valve applications are much better understood today than a few years ago. All manufacturers have methods to deal with this issue, and it varies depending upon design. The manufacturer should be consulted prior to design to help insure accurate and long-term proper operation.

Today's USM is a robust and very reliable device with many fault-tolerant capabilities. It is capable of handling a variety of pipeline conditions including contaminants in the natural gas stream. In the event of transducer failure, the meter will continue to operate, and some USM designs maintain excellent accuracy during this situation. When encountering contamination such as oil, valve grease, and other pipeline contaminants, today's USM will continue working and, at the same time, provide enough diagnostic data to alert the operator of possible impending problems.

The issue of re-calibration of meters, after a number of years of service, has been discussed for a number of years. Most users are flow calibrating their USM prior to installation. Whether to re-calibrate after a number of years still remains a question to be answered. Some designers have opted to install a secondary in-situ transfer standard in the field to verify performance on a periodic basis [Ref 8]. However, most users feel this method is too expensive and does not provide the necessary traceable certification that might be needed should the buyer of the gas question the accuracy of the primary meter. Thus, if a user is concerned, they have opted to remove a sample and return it to the calibration lab for checking.

As ultrasonic metering technology advances, so will the diagnostic features. In the near future USM diagnostic data will become even more useful (and user friendly) as more intelligence is placed within the meter. They will not only provide diagnostic data, but will identify what the problem is. When this happens, ultrasonic meters may be considered "*maintenance free.*"

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