MULTIPATH ULTRASONIC FLOW METERS FOR GAS MEASUREMENT

Class # 1220.1

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Introduction

The use of ultrasonic meters for custody (fiscal) applications has grown substantially over the past several years. This is due in part to the release of AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters [Ref 1], Measurement Canada's PS-G-E-06 Provisional Ultrasonic Specification [Ref 2], and the confidence users have gained in the performance and reliability of ultrasonic meters as primary measurement devices. Just like any metering technology, there are design and operational considerations that need to be addressed in order to achieve optimum performance. The best technology will not provide the expected results if it is not installed correctly, or maintained properly. This paper addresses several issues that the engineer should consider when designing ultrasonic meter installations.

Why Use Ultrasonic Meters?

Before discussing installation issues associated with ultrasonic meters (USMs), it might be good to review what the benefits of using USMs are. Since the mid-1990s the installed base of USMs has grown steadily each year. It is estimated that more than $65 million was spent worldwide on purchasing USMs in 2006. There are many reasons why ultrasonic metering is enjoying such healthy sales. Some of the many 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:** Minimal 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 important benefits to using USMs. The most significant, however, is the ability to diagnose the meter's health. The main question users want to know is whether the meter is still accurate after having been in service for some period of time in the field.

Other primary measurement devices such as orifice and turbine meters offer little insight into whether they are still operating accurately after some period of time. Issues such as contamination from pipeline oil and mill scale can impact the accuracy of any meter. Visual inspection is often required to validate proper operation for traditional primary measurement devices. Ultrasonic meters, on the other hand, offer electronic diagnostics that can help validate proper operation, and thus reduce the internal inspection requirements often required of other devices. These internal diagnostics can also be used to help identify whether the other components at the measurement station, such as temperature measurement and gas composition, are also operating correctly. For these reasons many designers are now specifying the use of ultrasonic meters more today than ever before.

USM Cost Comparison

No discussion about using ultrasonic technology would be complete without addressing installation and maintenance costs. Although this cost comparison with other measurement technologies is dependent upon many variables, the two most important are perhaps maximum and minimum anticipated flow rates. Other factors such as bi-directional requirements, operating pressure range, gas temperature, cleanliness of the gas, etc. also factor into the decision as to which primary measurement technology is best suited to the application. The benefits are difficult to quantify without knowing these conditions. However, generally speaking, if the operational range for a given application exceeds the capacity of a single meter, using USM technology may significantly reduce the capital expense (CAPEX) associated with the installation.

One reason the number of ultrasonic applications continues to grow is the reduced long-term cost of operation (O&M) and additional diagnostics that are available from this technology as compared to other measurement devices. These benefits have been well documented in papers presented at several conferences in the past [Ref 3, 4 & 5]. Certainly one of the most significant benefits is the reduction in maintenance. Unlike other technologies, USMs can be diagnosed without taking the meter out of service. In fact, this is often done remotely using LAN/WAN networks via Ethernet, dial-up phones, radios, or other communication techniques. All of these benefits, and many more, often provide the user with significantly lower O&M costs.

Sizing of USMs

Traditional measurement devices have been limited to flow rates that were equivalent to 50-60 feet per second (fps) maximum. Although high-capacity turbines operate in the 80-95 fps range, the majority of installations are still designed for the standard capacity meter. One of the significant advantages of ultrasonic meters is their ability to operate accurately in excess of 100 fps with no damage to the meter. In replacing orifice meters the “rule-of-thumb” is that the capacity of an ultrasonic meter is at least 1½ times that of an orifice meter.

Many users specify velocity limits in piping to minimize the potential for erosion in fittings (bends, elbows and tees) that can cause failure of the piping should the wall thickness become too thin. There have been reports of severe erosion of elbows downstream of meters that were operated above 100 fps for significant periods of time. However, there are several other issues that limit high velocity operation.

Higher velocity operation increases the stress on the thermowell(s). There have been reported cases of thermowells cracking when operated at high velocities. Some work has been performed to determine how accurate the RTD element remains when the thermowell is subjected to very high velocities. Studies indicate that vibration of the thermowell may cause the RTD to register higher due to “self-heating” that occurs when the RTD element rubs against the thermowell.

Higher velocities also create more differential pressure across today’s high-performance flow conditioners. The magnitude of this loss is somewhat dependent on the type of conditioner installed. However, typically the pressure drop at 60 fps is on the order of 2-3 psi differential (psid). If the gas velocity through the meter is increased to 120 fps, the differential becomes 4-9 psid. The increased velocity and subsequent differential pressure also can create higher noise, both audible and ultrasonic. The ultrasonic noise at these high velocities may begin to interfere with the meter’s operation. The audible noise may necessitate additional costs related to noise abatement or possible facility relocation to minimize impact on surrounding environment.

Primarily these reasons, most designers limit normal operation to either 70 or 80 fps. It is tempting to install a smaller meter and operate at higher velocities. However, the initial cost savings of going to these higher velocities can quite possibly be offset with increased maintenance and reliability problems that will occur later. The real benefit of the higher velocity capability is the ability to have accurate measurement at the higher flow rates which may occur during upsets or other abnormal conditions. In addition, the high velocity will not damage the meter as may be the case with orifice or turbine meters.

Low Flow Performance Issues

Traditionally USMs have been sized to operate so that the lowest velocity expected is between 5 and 10 fps. Using 5 fps as the lowest velocity provides a rangeability of 14-1 if the maximum velocity expected is 70 fps. Comparing this to traditional devices such as orifice and turbine this rangeability is generally better. However, larger turbine meters can approach this rangeability (and in some cases exceed this). Recently users have been asking how to increase the rangeability in order to help reduce CAPEX (capital expense) cost and operation maintenance cost (O&M, or OPEX) of the meter station. Since most users limit their maximum velocity to 70-80 fps, the only area left to expand rangeability is to operate the meter at lower velocities.

During the past several years many users have come to see the value in calibrating meters to velocities as low as 1 fps (and sometimes even lower). Calibrating a meter to below 5 fps is often referred to as a “low-flow calibration.” Generally 6-8 data points are used for calibrations with a 5-70 fps operation, and 2 additional data points, often 1 and 3 fps, are added for the low flow calibration. By lowering the minimum velocity to 1 fps the user has essentially multiplied the rangeability by 5!

A typical installation for a gas powered electric generation plant might include a 12-inch meter for the main flow rates, and a 6-inch USM for the lower flow rates. Assuming the lowest the 6-inch is operated is 5 fps, this would equate to about 1 fps for the 12-inch meter. This translates into a rangeability of approximately 80-1 by using both meters. Suppose a single 12-inch meter could be operated at this low velocity with a reasonable degree of accuracy. What would be the capital cost savings?

If the designer uses a low flow meter (say a 6-inch USM) with a 12-inch meter, in lieu of installing a single 12-inch meter, it would probably cost on the order of $60-90K more. By purchasing only one meter, and not having to do run switching with all the associated piping and control systems, the measurement station is also much easier to maintain. The capital cost saving is only the beginning. The benefit of less equipment translates into lower O&M costs for the life of the station. One hidden benefit is with no run switching, the possibility of the main run not activating is eliminated since there are no automated actuators required to open a valve. When a power plant goes online, and they aren't able to get the natural gas they need, this generally causes a loss in revenue, and the end user is not happy with the gas provider.

There are probably two major concerns about operating a USM at these low velocities. One is accuracy and the second is repeatability. The accuracy concern is from the absolute performance of the meter. That is, how accurate can the meter be after flow calibration at very low velocities? Another accuracy concern is how accurate will the meter be if there is thermal stratification (gas hotter at the top of the meter than at the bottom) within the pipeline. That is, if the gas temperature at the top of the pipe is hotter than the bottom, the measured temperature from the RTD will read higher, and thus under-registration is likely. Also, this can contribute to flow profile problems (distortion of the velocity profile) which also may impact metering accuracy, although this is generally not considered to be significant.

Both are valid concerns. However, with today's technology, these can be solved very easily. The key questions on accuracy are: "Does the meter provide a method of correction to reduce uncertainty at these very low flow rates, and can thermal stratification be identified? First, let's look at how to improve accuracy at very low flow rates.

Regarding the accuracy of a meter, a calibration technique called piece-wise linearization (PWL), commonly used for optimizing turbine meter performance, can be applied within the USM. This technique permits substantial reduction of the uncertainty at low flow rates. That it, assuming the meter is calibrated at the very low flow rate (velocity), the resultant uncertainty will become very small since any errors at these lower velocities have been corrected for. Thus, the meter's accuracy can be exceptional once calibration is complete, and the PWL technique has been implemented. Following is an example of a 12-inch meter that was calibrated from 2 fps to 118 fps.

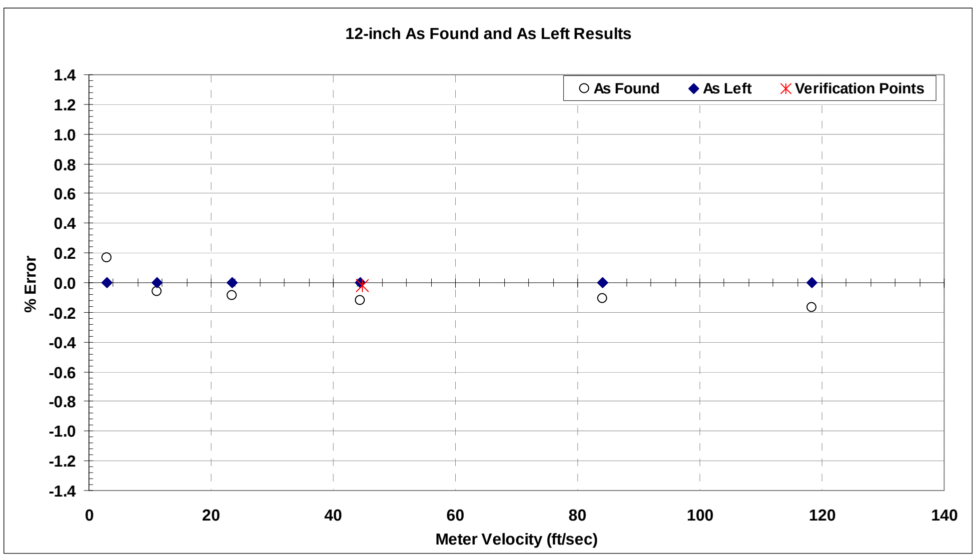

Figure 1 – 12-Inch Meter Calibration Results

As can be seen from this calibration result in Figure 1, the meter's performance at 2 fps deviated approximately 0.3% from the average of all the other flow rates prior to adjustment. It is important to note that even before adjustment, today's USM can easily provide accuracy values much greater than previously thought possible. This is due, in part, to the improvements in manufacturing and dry calibration that have been achieved during the past several years, and also to technology improvements in electronics.

After implementation of PWL meter calibration factors, all errors are driven to zero, so the uncertainty is essentially reduced to that of the lab. There is an additional uncertainty when operating between calibration points. This is because the PWL technique assumes the error between calibration points is a straight line. However, due to the typical linearity of the un-calibrated meter by using an appropriate number of data points at the low velocities, this added uncertainty should not exceed ±0.1%.

The second accuracy concern comes from the possibility of thermal stratification at lower velocities. A previously published paper discussed a 10-inch meter that had thermal stratification on the order of 2 degrees F [Ref 4]. This stratification occurred because the gas in the upstream piping was flowing at velocities below 3 fps, and more than 100 feet of the upstream piping was subjected to a bright sun. Also, there was a significant difference in gas-to-ambient temperature. One might say this is typical, but perhaps this is not a typical installation.

Most designs have the meter station's upstream piping below grade (underground). Piping emerges above ground and then makes a 90-degree direction change into the meter. With a 10-inch meter, this typically means 20-25 feet of piping is exposed to the sun and ambient temperature. In this condition, even when operating at 2 fps, the gas takes less than 15 seconds from the time it exits the elbow or tee to enter the meter run before it reaches the meter. In 15 seconds there probably is not sufficient time for any significant heat transfer to occur and cause stratification within the flowing gas stream. Thus, the possibility of thermal stratification of the gas at these low velocities is very minimal.

If significantly more upstream piping is exposed to ambient and solar effects than in the previous 10-inch meter design example, there is a possibility of thermal stratification. However, this can be easily detected by looking at the speed of sound reported by a meter that samples transit times horizontally. That is, if the gas temperature is hotter at the top, the SOS on the top path will read higher than the lower chord's SOS when compared to a metering gas velocity of 5-10 fps. By being able to see there is no deviation in SOS at the lower velocities, the user can have confidence that there is no thermal stratification, and thus temperature measurement is accurate. The caveat is that not all USM designs can provide this type of information.

To test the theory of thermal stratification, let's look at the change in the meter's path SOS over a range of calibration velocities. Figure 2 below shows the results of a 10-inch meter calibrated from velocities of about 1.8 fps to 118 fps.

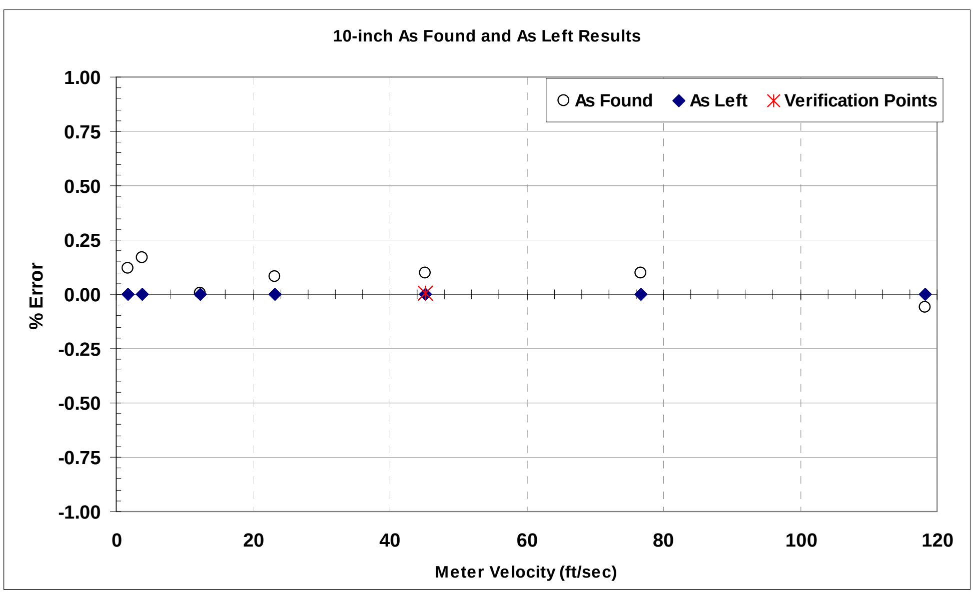

Figure 2 – 10-Inch Meter Calibration from 1.8 to 118 FPS

After meter adjustment the uncertainty of the meter would be that of the lab (about 0.2%) and the repeatability of the meter (probably on the order of 0.1% or less). At the lower velocities there could be some thermal stratification. Let's look at the path SOS values at two velocities to see how much stratification may have occurred.

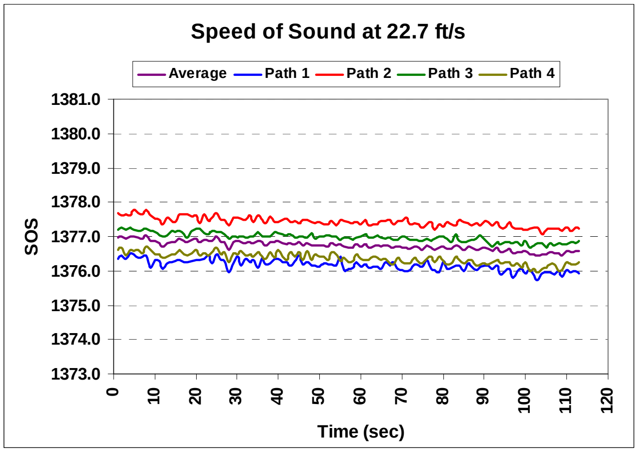

Figure 3 – Path SOS at 23 fps

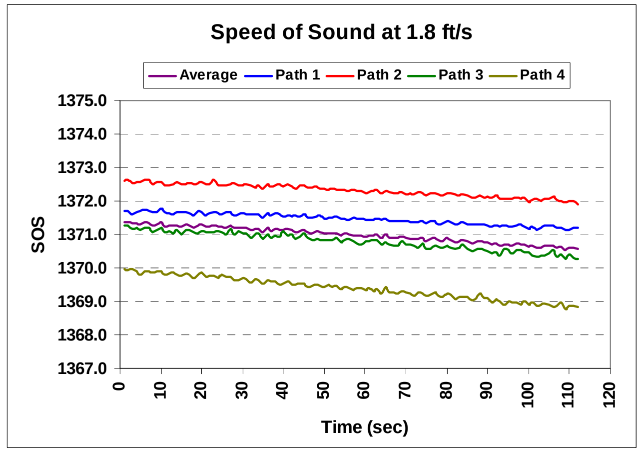

Figure 4 – Path SOS at 1.8 fps

Figure 3 shows the SOS difference of each path relative to the meter's reported SOS. This provides a good look at how consistent the individual SOS values are relative to the average. This figure shows that the spread of path SOS values is on the order of about ±0.05%, or less than 0.7 fps. Figure 4 shows the same meter at 1.8 fps and indicates the spread in SOS has increased slightly. Now the maximum deviation in SOS is on the order of 0.1%, or about 1.4 fps. Thus, we can see there is a little thermal stratification occurring since the path at the bottom of the meter (indicated by the gold colored line) is reading lower than shown in Figure 3, (relative to the average – purple line) and the path at the top of the meter (shown by the blue line) is now reading higher than in Figure 3 (relative to the average). Since higher temperatures increase the SOS of the gas, the path at the top now increases compared to the path at the bottom. This is an indication of thermal stratification, but the magnitude is very small, and thus there is no significant impact on the meters' uncertainty.

When a meter is operated at lower velocities, and thermal stratification is possible, there may also be a change in the velocity profile of the meter. Figures 5 and 6 show path velocity ratios from this meter at the same two velocities.

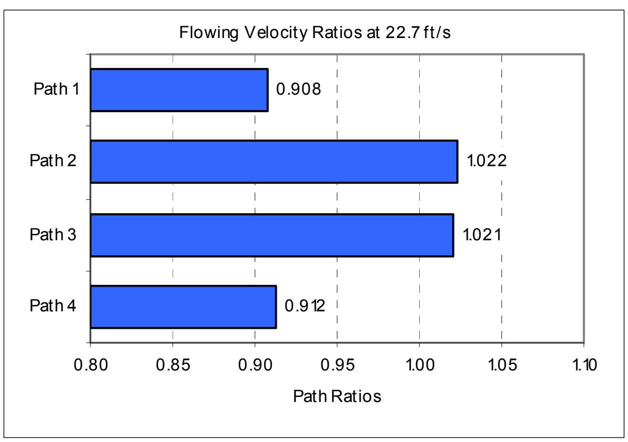

Figure 5 – Path Ratios at 23 fps

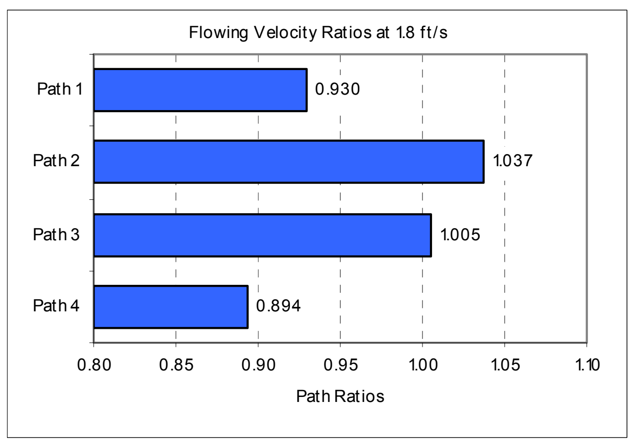

Figure 6 – Path Ratios at 1.8 fps

When this meter was operating at 23 fps, the path velocity ratios are symmetrical and normal. As the meters' velocity is reduced, we can see some change in the ratios. The values for paths 1 and 4 are no longer very close (about a 4% change), and the ratios for paths 2 and 3 also show some minor change (about a 3% change). This is normal at lower velocities, and does not have any significant impact on accuracy. This can be validated by viewing the "as-found" calibration data that is shown in Figure 2.

Let's use this 10-inch meter as an example for cost savings based upon low-flow performance. Suppose a site had an operational range of 225 MMSCFD to 5 MMSCFD at 750 psig. If the user selected an operational range of 5-80 fps, this would require a 6-inch meter to handle the lower flow rate at 5 fps. At 5 fps the 10-inch meter could handle approximately 14 MMSCFD. However, the engineer might decide to install a smaller meter since lowest flow rate is 5 MMSCFD. If the 5 fps minimum operation is followed, the designer would select a 6 inch meter to handle the low flow rate. The 10-inch meter would operate at 2 fps if no low flow meter were used. This is well within the accurate operation of the meter as shown in Figure 2.

Looking at the economics of adding the additional smaller 6-inch meter in this scenario, the added cost could easily exceed $75,000 when including the headers, valving, meter runs, RTU and actuators needed to sequence the 6 and 10-inch meters. A single 10-inch meter could be used for this example by operating it at 2 fps (instead of the typically lower limit of 5 fps), substantially reducing CAPEX, and certainly reducing the long-term O&M (OPEX) costs. Perhaps there might be some increased uncertainty. However, even if the uncertainty were assumed to be 0.1%, this would translate about $1.15 per hour based on $5 per thousand cubic foot gas price. Thus, there is probably not enough potential reduction in measurement uncertainty to justify spending more $75,000.

Dual or Multiple Meter Runs

For larger applications, many designers choose to use two similar sized meters in parallel. The break point often comes when the flow rate dictates a meter size of 16-inch and above. There are many variables to consider before choosing whether one meter is a better solution, or if two might be the best choice.

Two meters provide some redundancy. This might be important if company policy dictates removal and periodic re-calibration. Also, if maintenance policy requires periodic internal inspection, having two runs makes it much easier to perform this task without having to bypass the meter and estimate volumes. Additionally, should one meter develop an operational problem, having a second meter may help identify the problem(s) Of course the meters must be sized to be capable of handling the entire capacity should one be taken out of service, or this benefit may not be available.

The disadvantage of using two meters is obviously the capital cost and additional maintenance required. Two smaller meters will require more capital expense in the beginning, and most likely more long-term O&M cost. Which design is best for any given application somewhat depends upon the operational requirements, space limitations, flow rangeability, and other factors.

Generally speaking, designers that choose to use two or more meters in parallel don't do it for rangeability requirements. Today's USM provides at least 30-1 rangeability, and many are flow calibrating to achieve in excess of 80-1 rangeability. The primary reason is for redundancy and to permit removal of a meter for maintenance while measuring all station flow through the other meter(s).

Basic Piping Issues

As with any other technology, ultrasonic meters require adherence to basic installation guidelines. Recommendations related to the installation of primary metering elements, such as the orifice and turbine, have been in place for a long time. These are provided through a variety of standards (API, AGA, ISO, etc.) to insure accurate performance (within some uncertainty guidelines) when installed. The reason for these guidelines is that the meter's accuracy can be affected by profile distortions caused by upstream piping and proximity to noise generating control valves. One of the benefits of today's USM is that it can handle a variety of upstream piping designs with less impact on accuracy than other primary devices.

Installation effects on measurement devices have been studied in much more detail than ever before. This is due in part to the available technology needed for such evaluation. Much of this research has been focused on ultrasonic meters. Reducing uncertainty has also become a higher priority for pipeline companies today due to the increasing cost of natural gas. Designing an ultrasonic meter station that provides the same installed accuracy as that at the time of calibration is very important.

According to research work performed at Southwest Research Institute (SwRI) by Terrance Grimley, it would take a minimum of 100D of straight pipe for the profile to return to a fully symmetrical, fully developed, non-swirling velocity profile [Ref 6]. Complex upstream piping, such as two elbows out of plane, create even more non-symmetry and swirl than what was tested by SwRI. 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 must be followed to achieve a predictable accuracy.

In 1998 AGA released AGA Report No. 9 – Measurement of Gas by Multipath Ultrasonic Meters. The report was updated and revised in April 2007. This document discusses many aspects and requirements for installation and use of ultrasonic meters. Section 7.2.2 specifically discusses the USMs required performance relative to a flow calibration. It states that the manufacturer must "Recommend upstream and downstream piping configuration in minimum length – one without a 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 testing was conducted at SwRI in San Antonio, Texas to determine installation affects on USMs. Funding for these tests has come from the Gas Technology Institute, formally knows as the Gas Research Institute (GRI). Much of the testing was directed at determining how much error is introduced in a USM when a variety of upstream installation conditions are present. The results of the testing were presented in a report at the 2000 AGA Operations Conference in Denver, Colorado [Ref 6].

From this data one can conclude that upstream piping (elbows, tees, etc.) does have an effect on the meter's performance. One meter passed the installation affects test with no flow conditioner when located 20D from the effect. Nevertheless, most users still choose to use a flow conditioner in order to reduce potential upstream effects.

Which brand of flow conditioner to choose often depends upon the user's preference. From the SwRI report the results indicate that several brands and styles of flow conditioners work well. The only exception is that 19-tube bundle conditioners are not recommended by USM manufacturers as test results are inconsistent and generally not as good as other flow conditioners. This is due to the fact that these tube bundles are good for straightening the flow (eliminating swirl) but are ineffective in modifying and generating a consistent flow profile.

Each manufacturer has conducted extensive testing on their meter with and without a flow conditioner. From this data it is apparent that ultrasonic meters have reduced uncertainty when a flow conditioner is installed. With the price of gas expected to continue increasing for the foreseeable future, virtually all companies in North America install USMs with a flow conditioner. Not only does the flow conditioner reduce uncertainty, but it makes the velocity ratio diagnostics much easier to understand.

Figure 7 shows an ideal velocity profile for a 12-inch, 4-path meter with significant diameters of straight pipe upstream and a flow conditioner installed 10D upstream of the meter. Figure 8 shows the same meter with an installation effect of 3 elbows and a tee upstream of the piping (10D upstream of the flow conditioner).

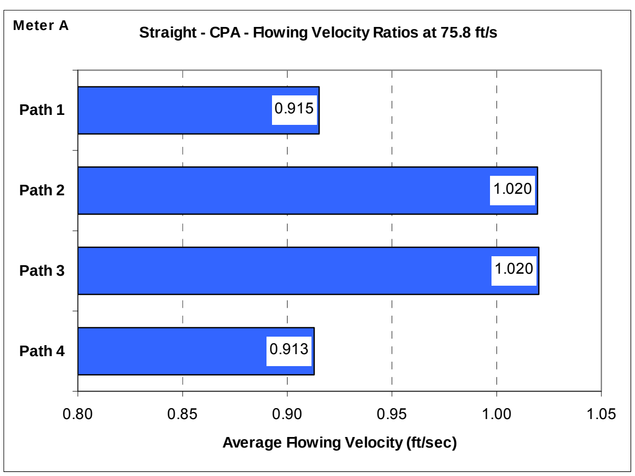

Figure 7 – 12-inch Path Ratios – Ideal

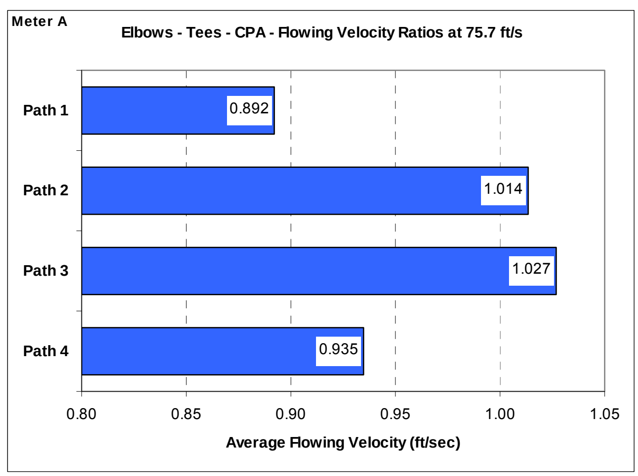

Figure 8 – Path Ratios with Installation Effect

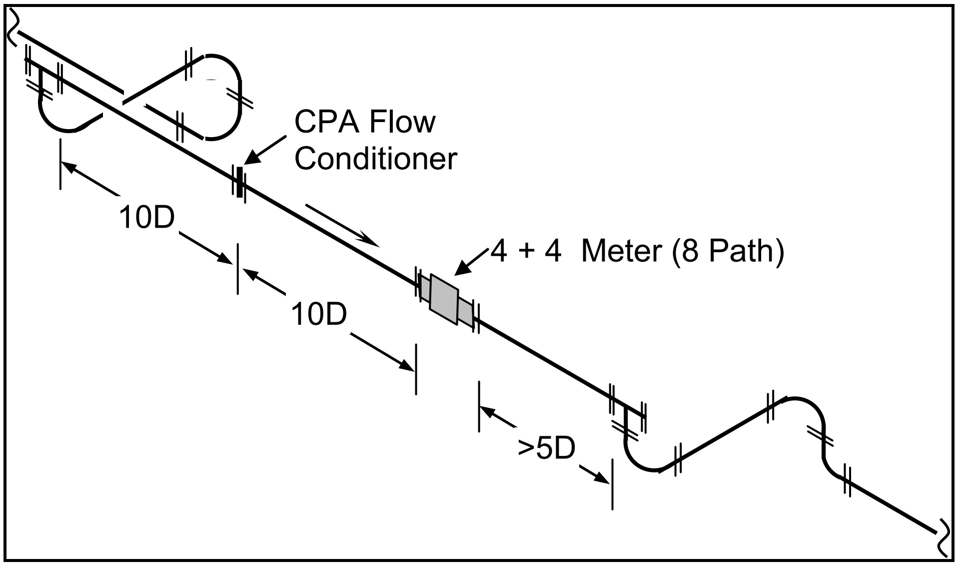

Figure 9 – 12-Inch Meter Upstream Piping Disturbance

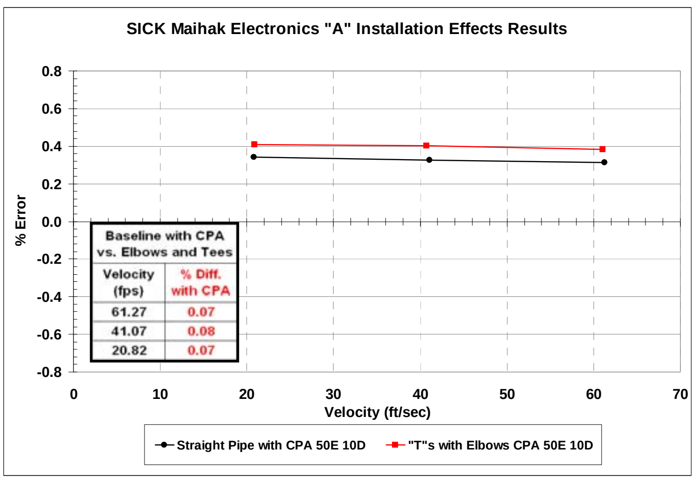

Figure 10 – Accuracy Impact on 12-inch Meter

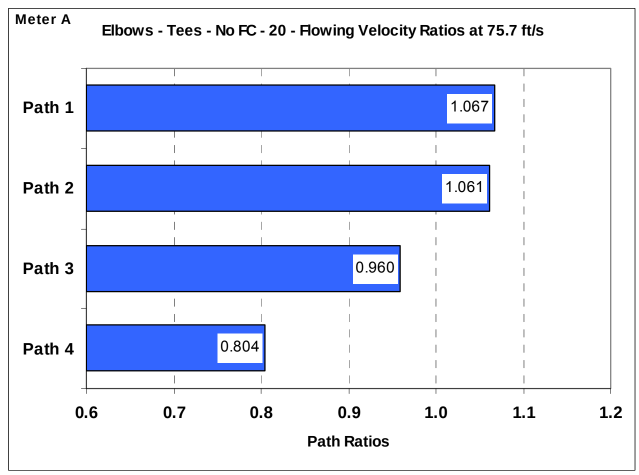

Figure 11 – Path Ratios with No Flow Conditioner

Figure 9 shows a pictorial drawing of the upstream piping disturbance that was used to create the less-than-ideal profile in shown Figure 8. Figure 10 shows the impact on accuracy the three elbows and one tee had on 4-path meter. The table inside of Figure 10 shows the effect on accuracy was less than 0.1%. Figure 11 shows what the profile looks like with no flow conditioner. Clearly this is a very distorted profile.

The effect on accuracy for the profile in Figure 11 was approximately 0.15%. Even though the error was small, having a profile that is this distorted makes understanding whether the meter is still operating correctly very difficult. Thus, most customers prefer to install a flow conditioner in order to have a profile that is much more like the baseline one shown in Figure 7.

Piping Recommendations

When AGA 9 was released in 1998, it did not include any recommendations for upstream or downstream piping lengths. At that time the GTI installation affects data was not available. Rather than specify any minimum requirements, it was decided to allow the manufacturer to state their recommendation based upon the meter's design and performance. With the data that is available today, most users have now adopted their own company standards. Although they vary from company to company, most are using a more conservative approach to insure the best possible performance in the field.

AGA 9 has been revised and the Second revision was released in April 2007. In Section 7, Installation Requirements, two recommended default piping designs, one for uni-directional and one for bi-directional applications, are included. For the uni-directional design there is a recommendation of two 10D upstream spools with a flow conditioner in the middle (10D from the meter). For the bi-directional design, both upstream and downstream recommendation would be two 10D spools with flow conditioners again located 10D from the meter. Figure 12 shows an example of the piping design recommendations. These are only recommendations and the use of the optional Tee or Elbow is strictly optional. The optional tee may be installed to help attenuate ultrasonic noise from control valves (see section entitle Control Valve Noise), or for ease of internal inspection of the meter run.

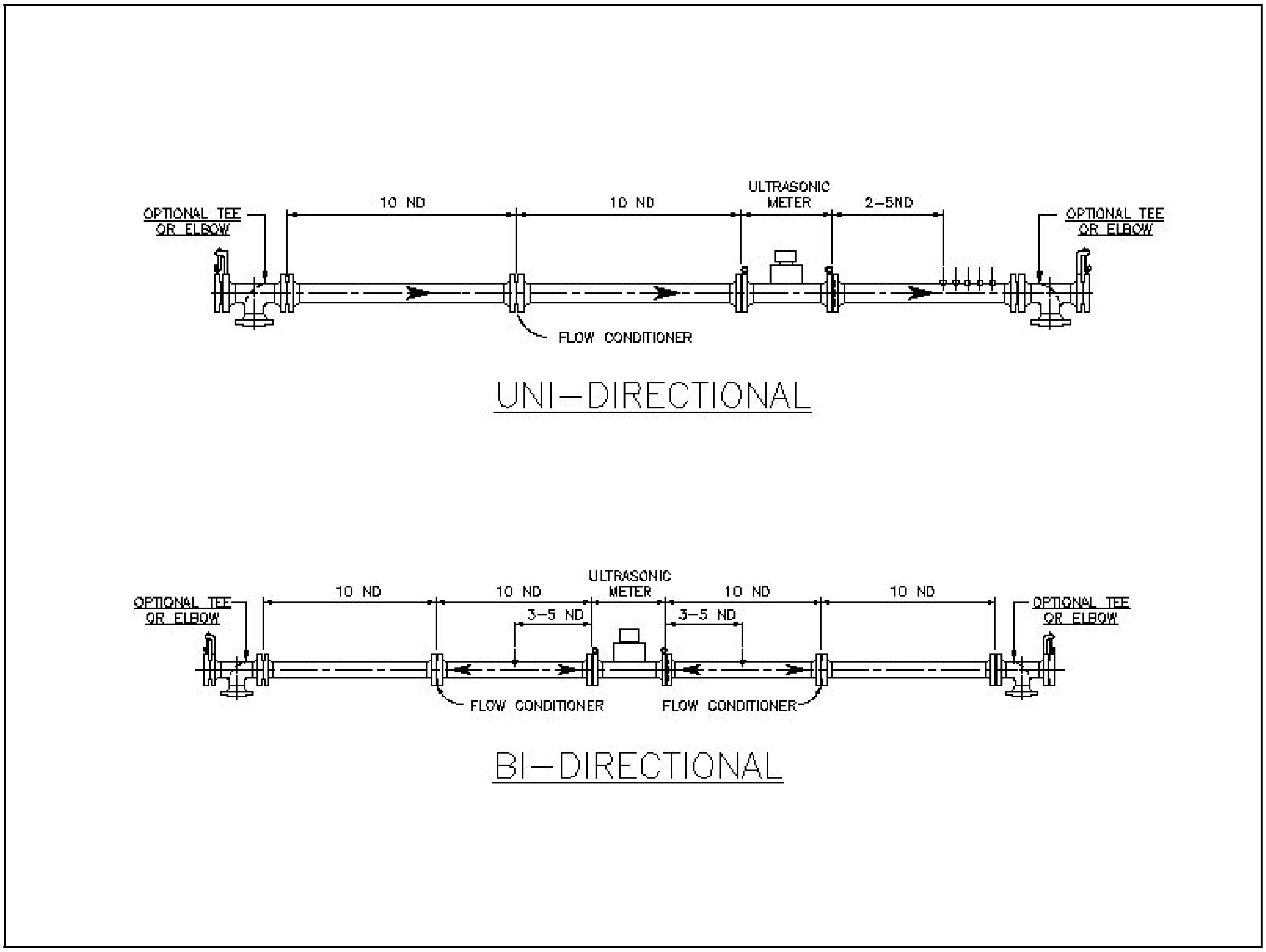

Figure 12 – AGA 9 Recommended Default Piping

The location of thermowells is discussed in Section 7.2.5 of AGA 9. It states that the thermowell should be located between 2 and 5 nominal diameters downstream of the meter. The reason for locating it close to the meter is for the same reason as other primary devices – to make sure the temperature at the RTD is the same as in the meter. For bi-directional applications, a potential issue arises. AGA 9 states the RTD should be 3-5D from the meter. This is to minimize the effect turbulence (caused by the protrusion at the inlet to the meter) may have on the meter's accuracy.

SwRI conducted tests with thermowells located a distances ranging from 1D to 5D upstream on more than one manufacturer of 8-inch ultrasonic meters. Results showed no measurable effect when the thermowell was at 3D, with only a slight influence at 2D. From this testing AGA 9 adopted the recommendation of a minimum of 3D upstream. Installing thermowells outside of the flow conditioner area (much further than 5D from the meter) may cause inaccurate temperature measurement.

Some designers include a tee upstream and downstream of the meter run. The purpose of the tee is to permit easy inspection inside the meter run. The addition of a tee, rather than an elbow, has long been used on orifice meters. However, some designers feel the introduction of a tee upstream of the meter creates a more distorted velocity profile. Although flow conditioners do a very good job of minimizing asymmetrical and swirling flow profiles, they are not perfect.

At present there is published data to show the impact a tee has on the accuracy of a meter. Testing presented at the CEESI USM Conference in 2004 and 2006 [Ref 7 & 8] showed the impact on installing an upstream tee, along with three elbows, and using 10D + CPA + 10D between the tee and the meter, to be on the order of 0.2%, or less, on the meter's accuracy. These tests produced much more profile distortion than simply installing one elbow and tee, and thus confirmed that using a tee upstream does not cause the USM to deviate outside the 0.3% requirement of AGA 9

Other Piping Issues

Using filters upstream of ultrasonic installations is often a subject of discussion. Many designers use filters to remove debris that may be traveling down the pipeline. However, due to the non-intrusive design of an ultrasonic meter, small particles generally pass through the meter with little or no damage. Also, some ultrasonic designs have transducers that don't protrude beyond the meter's wall, reducing the chance that flying debris will erode or damage them.

Another concern relates to the impact any potential buildup on the inside of the meter and associated piping will have on measurement accuracy. Using a filter or strainer may seem like a proper method of eliminating any potential coating or debris contamination that may occur. However, they may become a high maintenance item with the potential of becoming clogged if there is any significant amount of oil or particulate present. Assuming there is no oil or grease, particulates will just pass through the meter (if no filter is used).

Other concerns are that the filter or strainer will create a pressure loss in addition to possibly becoming clogged and subsequently breaking apart. Part of the element may lodge against the flow conditioner. This will impact the conditioner's operation, and most likely effect the meter's accuracy. This can be generally identified at the time of maintenance by observing the path velocity information. However, this will now require disassembly of the meter run to inspect and clean the foreign material. For these reasons, and the issue of cost and additional space requirements, using filters for ultrasonic metering applications is not usually beneficial.

Control Valve Noise

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

Meter 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 consulted prior to, or during the design phase, to ensure that the final design minimizes or eliminates any impact that could potentially reduce measurement quality.

The use of tees between the meter and the control valve to isolate control valve noise is very common. The actual design, number of tees, and location of meter relative to the control valve depends upon many variables. While elbows do provide some attenuation, tees provide at least twice as much. Although designers like to keep the control valve relatively close to the meter to minimize the facility's footprint, there is the drawback that the noise may interfere with the meter's operation. Figure 13 shows a typical design when the regulator is located upstream of the meter.

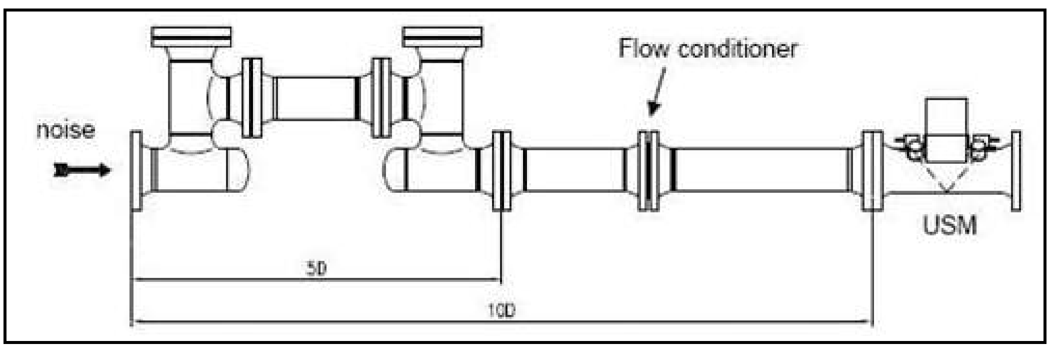

Figure 13 – Isolation Tees for Upstream Regulation

Today's new generation of transducers can handle significant levels of control valve noise. By using transducers that have a higher frequency, combined with higher efficiency and stronger sound pressure levels, the affects of control valve noise have been significantly reduced as compared to past generation of USMs. Figure 14 shows a picture of an installation with the control valve located immediately downstream of the USM.

Figure 14 – Control Valve Piping

The 2-inch control valve has audible noise reducing trim which typically creates more ultrasonic noise that has the potential to interfere with the meter's operation. In this test the meter was being operated at 600 psig and the regulator was producing about 200 psig differential. The meter's SNR went from a normal of 40 db to 24 db. For this meter when the SNR approaches 13 the meter would begin to reject waveforms.

Figure 15 shows the waveform of the upstream transducer during this test. Since the regulator is downstream, the impact of the noise is more apparent on the transducer facing the source of the noise (Transducer A). Figure 16 shows the same transducer's waveform with no differential, and thus no external ultrasonic noise.

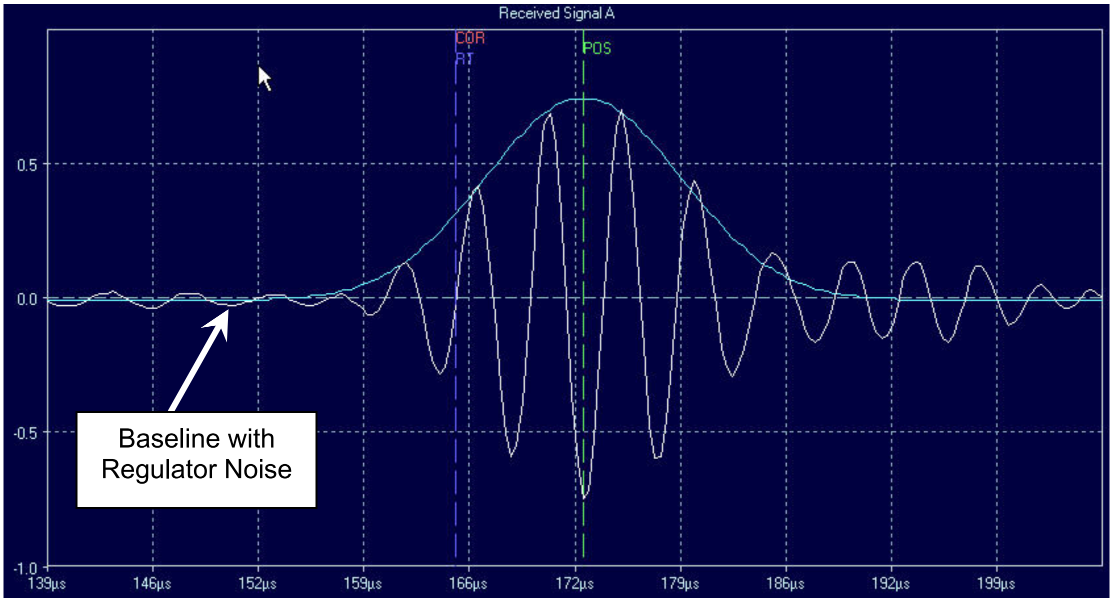

Figure 15 – Waveform with Control Valve Noise

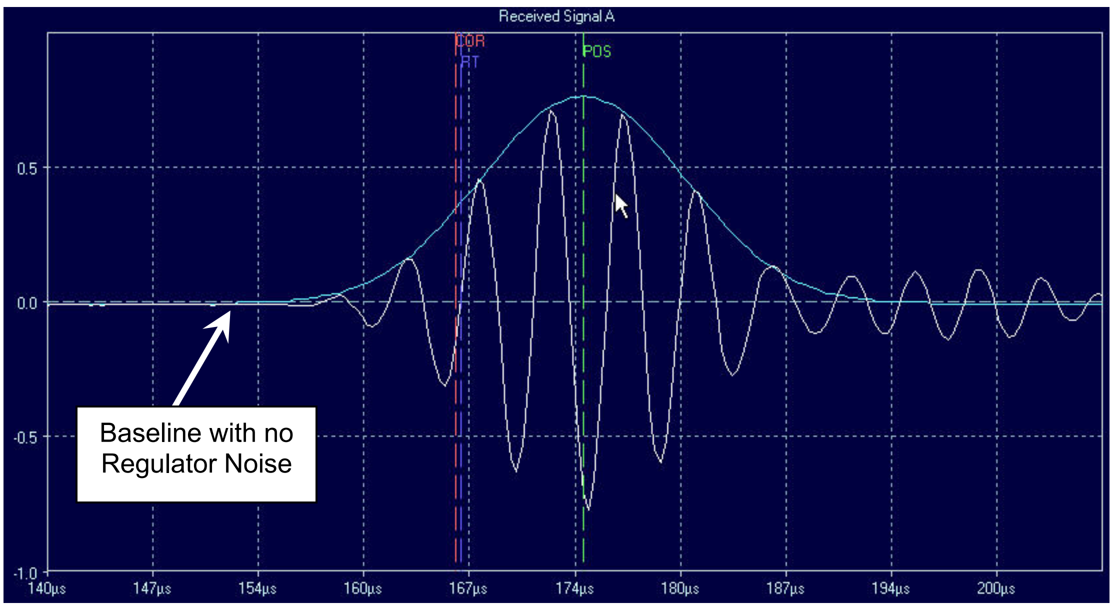

Figure 16 – Waveform with No Control Valve Noise

When a transducer sees external ultrasonic noise, it will be identified by looking at the beginning of the received waveform. The difference between these two waveforms (Figure 15 and 16) is obvious when comparing at how flat the line is prior to the reception of the wave. In Figure 16 the baseline is very flat, but in Figure 15 the baseline has some variations which indicate noise is present.

Control valves can create enough noise to potentially overpower the USM's signal. Depending upon the manufacturer, control valves may be located near the USM meter as has been done for turbine and orifice meters. However, for best results, the regulator should be installed downstream of the meter. Locating the valve downstream will result in a higher pressure upstream at the meter. The denser gas at the USM will result in a stronger signal from the transducers, making it easier to differentiate the meter's signal in the presence of extraneous noise. As stated earlier, tees between the meter and the control valve provide approximately twice the noise attenuation when compared to elbows. A more detailed discussion on how to design USMs with control valves was presented in a paper at the Western Gas Measurement Short Course in 2007 [Ref 9]. Another benefit of installing the regulator downstream is typically a smaller meter can be used when it is installed upstream. This can significantly reduce the cost of the metering station.

Testing of USMs with control valve noise is ongoing with all manufacturers. Better methods of handling extraneous noise are constantly being developed. The most important thing to remember is to consult with the meter manufacturer before or during the design phase.

Flow Calibration Basics

The primary use for USMs today is custody measurement applications. As 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. Initially the 1998 release of AGA 9 did not require meters be calibrated for fiscal use. However, with the publication of Revision 2, it is now a requirement for all fiscal (custody) applications.

The basic accuracy requirement, prior to any adjustment, is that 12-inch and larger meters must be within ±0.7%, and 10-inch and smaller meters to be within ±1.0% for the flow range of q_t to q_{max} (low flow rate to maximum flow rate). Below q_t, the error limit is ±1.4%. If the meter is outside these values, and is calibrated with upstream piping and a flow conditioner (considered the package), then the user is permitted an additional 0.3% tolerance on the "as-found" of the meter. Even though the meter may still be outside of this, the User now has the option to accept if they want. Thus, the "out of the box" performance has less meaning today than in the previous AGA 9 version.

Initially USMs were installed without a flow conditioner. However, customers are using flow conditioners in the majority of applications today. Many feel that using a "high performance" flow conditioner (not a 19-tube bundle) provides more consistent performance (reduced uncertainty). Even though data exists to support the supposition that some USMs perform quite well without flow conditioners, the added pressure drop and cost is often justified by the reduction in uncertainty. One thing that most everyone does agree upon is that if a flow conditioner is used with a meter, the entire system should be calibrated together.

It should be noted that one of the benefits of the ultrasonic meter is that it does not create significant pressure loss. The pressure drop resulting from the flow conditioner is offset by the lack of pressure drop across the meter (when compared to orifice or turbine meters). As such, total pressure loss across the metering facility as a result of using flow conditioner is probably no greater than with other primary devices for the same given flow rate.

Most companies have standard designs for their meters that typically specify piping upstream and downstream of the flow conditioner(s) and meter. Usually these USMs are calibrated as a unit with the customers upstream and downstream piping spools. Calibrating as a unit helps insure that the accuracy of the meter, once installed in the field, is as close as possible to the results provided by the lab.

In the past most customers felt their applications deserved, and required, less uncertainty than the minimum requirements of the original AGA 9 (where flow calibration was not required). To ensure these higher standards were met, virtually all users began flow calibrating their USM meters used in custody transfer applications since the late 1990's. At the 2002 AGA Operations Conference a paper was presented that discussed the benefits of flow calibrating ultrasonic meters [Ref 12]. Summarizing from that paper, there are three main reasons users are calibrating meters:

- Reduce uncertainty
- Verify performance
- Improve rangeability

Calibration Labs

There are several flow labs in North America that provide calibration services. Each will calibrate to any number of points the designer feels are necessary. Typically most designers are requesting 6 to 8 data points. Once all the "as-found" data points have been determined, an adjustment factor (or factors) is (are) computed. Facility personnel enter the value(s) into the meter. Usually one or two verification points are used to validate the predicted "as-left" performance. That is, the lab will select one or two flow rates and verify the meter error is zero (or very close to zero). Generally the USM will repeat within ±0.1% of the predicted value, with more recent results showing verifications typically on the order of ±0.05%.

During the late 1990's two large-capacity calibration facilities were commissioned in North America. These two laboratories permit users to cost-effectively calibrate larger USMs (greater than 10-inch) to full capacity, thus reducing the uncertainty related to measurement error when installed in the field. In 1998 when AGA 9 was first published these two facilities were not in operation. Since there was no large capacity calibration facility in North

America in 1998, AGA 9 did not require flow calibration. However, the new release of AGA 9 requires flow calibration for fiscal (custody) measurement applications.

Even though there is a substantial amount of data showing USMs to be linear to better than ±0.2%, many want to reduce this error further. Because of this, some users have implemented multi-point linearization (PWL), within their flow computers, to further reduce the uncertainty of their USM calibration results. This is not a new technique, and has often been used for turbine meters in the past.

When using this multi-point linearization technique, external to the USM, at least two issues always surface. First, the output signals from the USM (serial, frequency and analog) would then be adjusted in the flow computer to correct all errors. If the output signal (serial or frequency) from the meter is sent to two separate flow computers, care must be taken to ensure both computers are utilizing the same algorithm, or their results will differ. Second, since the linearization is not taking place in the meter, there is no audit trail within the meter to verify the output has been adjusted and then verified ("as left" tests to validate proper adjustment). This was discussed in more detail in an AGA 2002 paper titled "Benefits of Flow Calibrating Ultrasonic Meters [Ref 12].

To overcome the above problem, some USM manufacturers have provided the user with the ability to implement PWL in the meter's electronics. This allows the linearization to be tested and verified at a test facility, and the meter output does not require external correction which has its inherent problems.

Re-Calibration

AGA 9 does not require an ultrasonic meters to be re-calibrated, and will not require this in the upcoming revision. As USMs have no moving parts, and provide a wide range 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 with a significant number of meters.

The use of USMs for custody transfer applications began increasing rapidly in 1998. Now, with more than 9 years of installed base, there is significant information to conclude USMs may not 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 may not require re-calibration.

During the past several years, many meters have been re-calibrated in Canada. Their governmental agency, Measurement Canada, requires USMs to be re-tested every 6 years. The data obtained from these meter re-calibrations, from random re-testing by customers, and long-term data from meters at calibration labs typically shows the meter to be within ±0.3% of the original calibration assuming the meter is clean and operating correctly.

Several users in the US have removed meters in the past year and returned them to the calibration facility for a quick verification. If the meter is clean, the performance on these has typically been within ±0.1-0.3%. Unfortunately, there is very limited published information to date. Over the next several years, the industry's knowledge base with respect to the long-term accuracy of the ultrasonic meter will continue to grow.

Some designers have chosen to incorporate a separate "reference" meter in their larger stations [Ref 13]. The purpose of this meter is to provide an in-situ verification against all the other fiscal meters at that location. The idea is to route all the gas from a given operational meter periodically through the "reference" meter and make any adjustment based upon the difference. In many ways this is exactly what the calibration facility is doing. However, this technique has several issues that must be addressed.

First, if there are any installation effects on the reference meter, a bias could be introduced in the results. The installation effect could come from the upstream piping or pipeline contamination. Second, the addition of a reference meter adds significantly to the cost of the station. Not only is the designer paying for the additional reference meter, there is an additional cost for each meter run as a separate ball valve must be included to permit diverting the gas through the reference meter. Additionally, the extra reference run requires more space on the skid that adds to the cost. Also, using a reference meter on location somewhat limits the ability to verify performance over the entire range of operation. Finally, removing a meter and having its performance verified at a calibration facility provides an independent analysis of the meter's performance. This would most likely be required in the event of a dispute by the purchaser of the gas.

Other Design Issues

EMI/RFI

The USM is electronic in nature. As such, some believe it is susceptible to electro-magnetic interference (EMI) from high voltage power lines. Today, manufacturers enclose electronics in well-shielded metal housings that are virtually immune to any typical field EMI problems. Installations have been done where 200,000+ volt AC power lines are virtually overhead of the meter with no impact on operation.

Radio frequency interference (RFI) can also affect electronic devices. Again, all manufacturers provide a high degree of protection by enclosing the electronics in grounded metal housings. However, the designer is cautioned to insure that all the wiring that is attached to the meter is also grounded. There have been reported cases where high-power radio transmitters, such as Ham radios, can interfere with a meter's operation. By installing shielded wiring, and following proper grounding recommendations, this potential problem can be eliminated.

Communication issues

Most USMs communicate with external devices using either RS-232 or RS-485. The general recommendation for serial communication varies by designer. For distances up to 250 feet, serial communication has been shown to be very reliable, depending upon baud rate. This distance is substantially longer than the traditional 50-foot limitation that used to be the standard maximum recommended length. Using a low-capacitance cable, specifically designed for data communication, is very important to insure quality serial, RS-232 communication when data rates exceed 9,600 baud.

The actual maximum distance is somewhat dependent upon communication speed. That is, for higher speed communication (beyond 9600 baud) the reliability may be less, necessitating shorter lengths, or switching to RS-485. For this reason, designers generally choose to use RS-485 for lengths in excess of 250 feet. Here the distances can easily be several thousand feet with no degradation in communication performance. For distances of 50-100 feet, RS-232 can easily operate at 38,400 if the proper data communication wire is used.

Another feature many designers take advantage of is the ability to remotely access a meter. Some USM manufacturers provide software that supports remote, dial-up access. When using a meter that provides Ethernet connectivity, remote access becomes even easier if the site has wide area network (WAN) access. With this type of communication a technician can be on a computer, virtually anywhere in the world, and communicate directly to the USM, via the Internet. The Ethernet connection provides tremendous bandwidth capabilities and also permits more than one computer to communicate simultaneously with the meter. Even if the site does not have Internet access via a WAN, some users still install the wiring and also an Ethernet hub. This permits several laptops to simultaneously communicate with the meter with no interference with each other.

A common remote access strategy is to attach a USM serial port to a modem. Although slower than the Internet, it does permit remote monitoring and troubleshooting without the need to for a site visit. When designing an ultrasonic meter installation, consideration should always be given to utilize remote access as it can often provide substantial savings for a small monthly investment. Since other equipment at the measurement site, such as gas chromatographs and flow computers, also support remote access, either via Ethernet or serial communications, it is not uncommon for all three to be accessed via the same phone line.

Ambient Temperature

Today's USM is designed to handle a wide range of ambient temperature conditions. Electronics typically can operate from a minimum of –40 °F to a maximum of +140 °F. Thus, the meter can be installed in most applications without the need for a shelter or building. Typically if the designer has an application where temperature extremes are present, they may include a shelter more for the technician's benefit than the meter's requirement.

Power

Most applications today utilize remote AC power to operate the USM rather than solar or thermal electric generators (TEG). Although solar and TEG are feasible, the typical installation also has other "higher-power" consumption components such as flow computers, gas chromatographs and communication equipment.

As with all electronic devices, providing a reliable power source is important. Designers typically utilize an uninterruptible power supply (UPS) to insure reliable service. Some USM manufacturers provide power loss alarms in the meters audit history. This can be very helpful in the event of intermittent power problems. First, it indicates there is a problem by logging an alarm. Second, by knowing the date and time of the event, determining the amount of downtime can assist in estimating the volumes missed. Also, knowing the date and time may be helpful in solving the power problem.

Pulsation

One problem for just about any measurement device is how accurate it performs when subjected to pulsation. The effect of pulsation on orifice meters has been studied for years, and many reports have been written. As the USM is a non-intrusive device, it might be assumed there would be little effect on its accuracy. However, this may not always be the case.

Some independent testing has been performed on several brands of USMs. To date very little has been published. However, it is safe to say that pulsation, given the right conditions, can impact the accuracy of an USM.

In 2007 a series of tests were conducted at the Nova Didsbury test facility on a chordal meter that provides a diagnostic called Turbulence. During the testing a wide range of pulsation frequencies, two different velocities and two different pulsation levels were introduced upstream of the meter. By using Turbulence, it may be possible to correlate the level of Turbulence to any errors produced by the meter. This would then provide the needed diagnostic to help insure any meter installed with pulsation present is still working accurately.

Figure 13 shows the pulsation generator used for this testing. Essentially it is a rotating disc that is driving by a hydraulic motor at different speeds to obstruct the flow through the center of the assembly (see arrow in Figure 13). To create different frequencies, the speed of the motor is changed. To create different levels of pulsation, the bypass valve (show in Figure 13) is throttled. To create more pulsation, the bypass is closed down forcing more gas to flow through the pulsation generator.

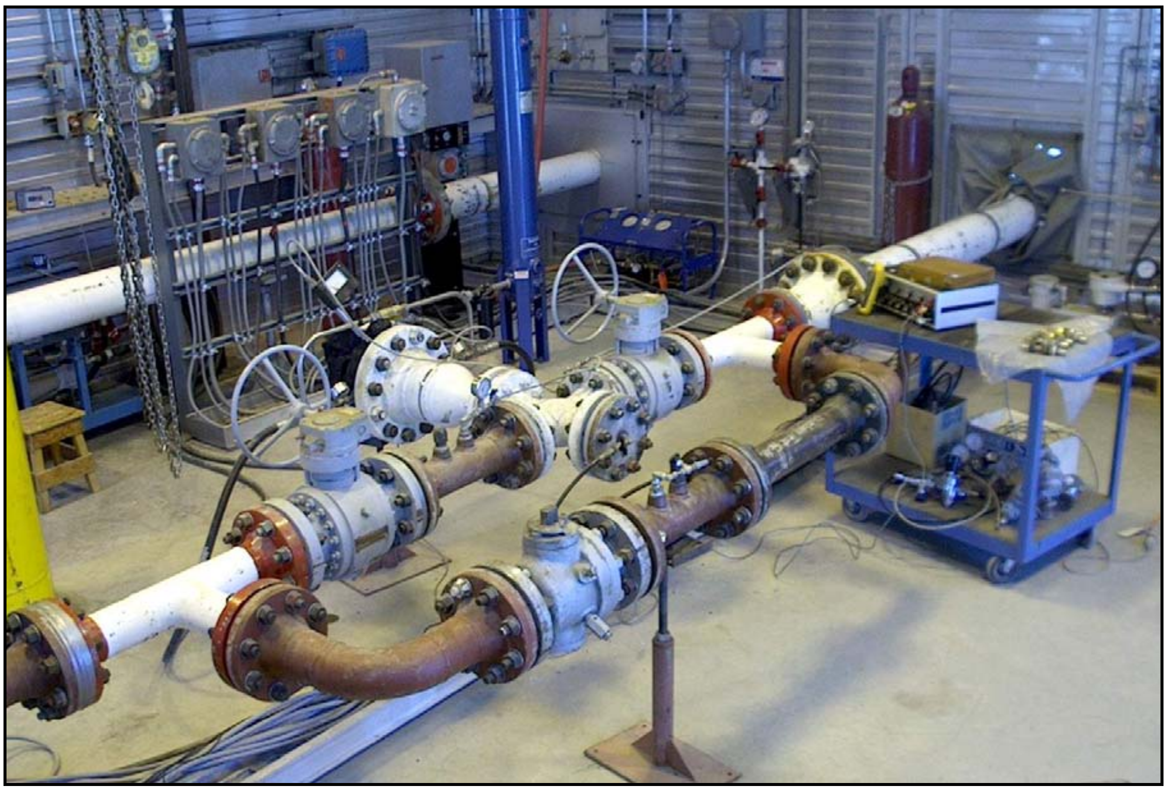

Figure 17 – Nova's Didsbury Pulsation Generator

Figure 18 – Meter Pulsation Testing at Nova's Didsbury Facility

Pressure Effect Issues

No discussion on calibration of USM would be complete without bringing up the issue of calibrating at one pressure and operating at another pressure. Testing conducted at SwRI, under the funding of the Gas Technology Institute (GTI), has shown some potential for a meter's performance to shift with pressure [Ref 14]. Additional testing has been performed at various other calibration facilities and generally does not support this conclusion.

The results for different manufacturers do show somewhat different pressure effect results [Ref 15]. Currently USM manufacturer's state there is virtually no pressure effect (change in meter accuracy when the pressure changes). Each has conducted testing at other facilities to show there is little, if any, effect. However, the issue still remains. At present the pressure effect, if there is one, is probably not more than 0.1-0.2% for meters calibrated at 1000 psig and operated at 200 psig. Since most transmission companies typically operate above 600 psig, calibrations done at the high-capacity facilities probably don't introduce any significant bias.

If an ultrasonic meter is operated at lower pressures, say 45 PSIG, then most certainly there will be an effect if this meter had been calibrated at say 500 psig. The change in accuracy comes from a change in profile that can be related to a dimensionless number called Reynolds number. For a USM to operate over extremes in pressure like this example, it would experience an accuracy shift it the meter didn't employ a real-time Reynolds Number correction.

Dirty Meter Considerations

Just like any measurement technology, if the meter is not properly maintained, performance will suffer. Today's pipelines are generally relatively clean. However, there is always the potential for mill-scale and oil to coat the inside of a meter. This coating will impact the accuracy. The magnitude and impact on accuracy appears to be somewhat dependent upon meter design. Several papers have been published on this issue [Ref 5, 13 & 17]. The good news here is that USMs are probably less sensitive to performance changes due to contamination than other technologies. Maintaining a clean primary measurement element is just as important as calibration of ancillary devices. Many users have regularly scheduled inspections to insure optimum performance.

Today's powerful software also makes it much easier to identify potential dirty meter conditions. By collecting the data from the USM, indications of pipeline buildup can often be identified. Other issues, such as partial blockage of a flow conditioner, can easily be seen using the proper diagnostic techniques. The ability to diagnose potential problems, even remotely, is certainly one of the major benefits in using USMs, and should not be under-estimated when designing a station.

Several papers have been published showing examples on how a meter's performance can be diagnosed using software [Ref 5]. The ability to recognize when problems are developing has helped many users to reduce their measurement uncertainty over the past several years, and thus lower their Lost and Unaccounted For (LAUF) volume. In many cases this has translated into a significant increase in a company's "bottom-line" revenue.

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 dramatically because they provide significant value to the customer by reducing the cost of doing business. The benefits of using USMs have been well documented over the past few years [Ref 3 & 4].

More applications than ever before are being designed today using this technology. Just like any measurement device, it must be installed and maintained properly to insure optimal long-term performance. The best of technologies will not provide the expected benefits if it's not installed and maintained properly. The designer must take into consideration all aspects of the station requirements in order to realize the potential for this technology.

USMs provide a much wider rangeability than other devices, while reducing measurement uncertainty to significantly lower levels. Often fewer meters are required because of this rangeability, further reducing capital and operational costs. This increase in rangeability and improvement in accuracy has often been attributed to the reduction in LAUF most companies have realized during the past 3-5 years.

Today it is not uncommon for designers to operate their USM from 1-80 fps, and obtain accuracy (after calibration) on the order of 0.1% relative to the lab. By extending the operational range below the traditional 5-10 fps at the low velocity region, USM rangeability is now permitting the designer to reduce the number of meters needed thus saving CAPEX dollars that range from $50K to more than $100K for larger stations.

Installation effects on USMs from upstream piping, such as elbows and tees, are generally thought to be less than with other technologies. Most customers are using flow conditioners to minimize the potential impact upstream piping may have on a meter's accuracy. Additionally, virtually all designers are requiring the USM, and all associated meter run piping, to be flow calibrated as an assembly, further reducing uncertainty. After flow calibration, most users leave the entire meter run assembled if possible. This reduces the chance of improper installation in the field such as installing the flow conditioner backwards, in the wrong place, or misalignment of the meter piping.

The issue as to whether re-calibration of ultrasonic meters is required is still outstanding. Canada currently requires the USM to be tested at least once every 6 years. Other North American customers aren't required to re-calibrate, and most are undecided as to the potential added value this may bring. Some designers have opted to install a secondary in-situ transfer standard in the field to verify performance on a periodic basis [Ref 13]. However, most designers feel this method is too expensive and does not provide the necessary traceable certification that might be needed should the buyer of the gas questions the accuracy of the fiscal meter. Thus, if a user is concerned, they generally prefer to remove a meter and return it to the calibration lab for re-verification.

Using an ultrasonic meter in conjunction with a control valve (regulator) requires special attention. 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 meter design. The manufacturer should be consulted prior to the facility design phase to help insure appropriate considerations are implemented, thus minimizing adverse effects on meter accuracy and performance.

Today's USM is a robust and very reliable device with many fault-tolerant and problem detection 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 [Ref 8]. When faced with 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 measurement accuracy problems.

Making provisions for remote access to the ultrasonic meter can translate into significant long-term savings. Designing a station to include remote communication not only is a benefit for maintaining the USM, but it can significantly assist in maintaining other measurement equipment.

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