FUNDAMENTALS OF ULTRASONIC FLOW METERS

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Natural Gas Flow Meter History

Although they are considered relatively new, transit-time ultrasonic flow meters for natural gas measurement date back more than 25 years. In the late 1970's, Columbia Gas Research undertook a cooperative program to develop ultrasonic check meters for Columbia Gas Pipeline, with Panametrics, Inc., then a company that was well known for ultrasonic nondestructive testing technology. At that time, transit-time ultrasonic technology was well established for liquid flow metering utilizing both wetted and clamp-on installation methods, but the technology had not yet been commercialized for gases. The difficulty that had to be overcome when using ultrasonic flow meter technology for gas metering was the mismatch of acoustic impedance between the ultrasonic transducers and the gas. That mismatch makes the transfer of ultrasonic energy into a gas difficult, much more difficult than transferring ultrasonic energy into a liquid. Panametrics developed a successful way of acoustically coupling ultrasonic transducers to gases. That invention was the cornerstone of ultrasonic flow measurement for gases.

Columbia Gas Research had been encouraged by early tests using a mechanical method of creating an acoustic wave in natural gas pipelines. The resulting ultrasonic program was successfully concluded in 1982 with prototype meters installed at various locations in the Columbia system and at additional locations via a collaborative program with other pipeline companies. Single and multi-path meters were installed that proved the viability of the technology for the intended application. Most of the meters were used to balance pipeline flows. At the conclusion of the program, the first six-path quadrature gas flow meter was installed in parallel with a conventional metering station. It gave encouraging results for the use of ultrasonic flow meters for custody transfer. All in all, the program started the natural gas ultrasonic flow meter along the path to where it is today.

Why Use Ultrasonic Flow Meters?

Transit-time ultrasonic flow meters offer unique advantages to pipeline operators. They create relatively little pressure drop, have no moving parts, require very little maintenance and can easily handle large pipe sizes. Differential pressure and turbine meters cause a pressure drop in operation. Compressors must restore lost pipeline pressure, which adds to operating costs. Turbine meters have moving parts, a rotor and bearings that turn in proportion to flow velocity. The rotor and bearings are subject to wear. Grit and liquids in flowing gas can increase maintenance requirements of differential pressure and turbine meters and eventually lead to accuracy degradation. Because ultrasonic meters create little pressure drop and do not wear, their operating costs and cost of ownership can be low when compared to other meter types.

Ultrasonic meters for natural gas custody transfer are generally best suited to pipes larger than 6 inches. The operating principle of transit time ultrasonic meters is such that the longer the path over which the ultrasonic pulse travels, the greater the accuracy potential of the meter. The actual measurement a transit-time ultrasonic meter makes is the time it takes for ultrasonic pulses to travel over the fixed distance between ultrasonic transducers. The time needed for the pulse to travel the longer distance in larger pipes is greater than in smaller pipes, so greater accuracy is possible. Transit-time ultrasonic meters are used on pipes as large as 42 inches, with 12 and 24 inches being typical. In addition, because of their wide turn down ratio, typically greater than 100 to 1, a single ultrasonic meter can handle all the flow through a large pipe. Often, a metering station consisting of multiple differential pressure meters is needed to measure high flow rates in large pipelines. Typically a single ultrasonic meter can be used instead of multiple differential pressure meters in such situations, further reducing cost of ownership.

Flow Profile Effects

These factors help explain the rapid growth of ultrasonic flow meter use in natural gas custody transfer use since the middle 1990's. But, because of the way transit-time ultrasonic flow meters operate, flow profile disturbances can cause inaccuracies.

Natural gas custody transfer transit-time ultrasonic flow meters are multipath meters that use two ultrasonic transducers per path. The transducers are mounted through valves into the pipeline so that they are in acoustic communication with one another. That is to say, each transducer in the pair can receive ultrasonic signals transmitted by the other transducer in the pair, and vice-versa (see Figure 1).

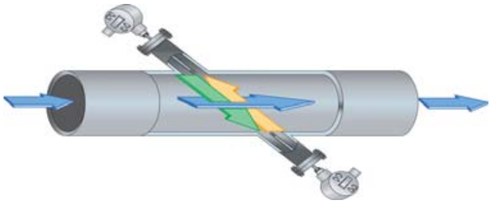

Figure 1: Ultrasonic Transit Time Principle

During normal operation, each transducer acts as a transmitter for a certain number of pulses and as a receiver for an identical number of pulses. The time interval between transmission and reception of the ultrasonic pulses is measured in both directions. If the gas is not flowing, the transit-times in each direction will be equal. If the gas is flowing, the transit-time in the direction of flow will be less than the transit-time in the opposite direction and the difference between the two transit-times is proportional to the velocity of the flowing gas.

The flow meter collects and statistically analyzes a large amount of data in a short period of time, and then calculates the velocity from an equation of the form:

$$V_{av} = K\ (P/2 \cos \Theta)\ (\ \Delta t\ /\ t_{up} + t_{down})$$

Where:

V_{av}	=	Area averaged flow velocity
P	=	Path length
Θ	=	Angle between the acoustic path and the flow
K	=	Flow profile correction factor
t_{up}	=	Upstream Transit Time
t_{down}	=	Downstream Transit Time
Δt	=	$t_{up} + t_{down}$

If the flow profile is perfectly symmetrical, a single path meter with the proper flow profile correction factor applied will average the flow properly and give excellent accuracy. However, in many gas pipelines the flow profile is disturbed. Typical forms of disturbances are shown in Figure 2 below. Partially closed valves, elbows or other pipeline configurations can cause disturbances such as these. A disturbed flow profile will cause ultrasonic flow meter inaccuracy unless steps are taken to either measure the flow at multiple points and calculate the correct average flow rate, or to condition the flow into a symmetrical profile.

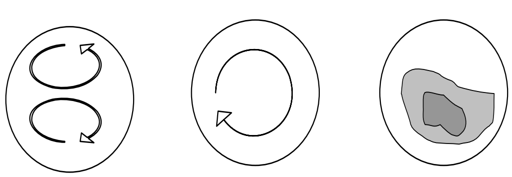

Figure 2: Types of Disturbed Flow

Originally, the multipath design used to correct the indicated average flow velocity for such disturbances was a quadrature configuration. The quadrature design used 6 pairs of transducers at precise locations across the pipe (Figure 3). Using a quadrature configuration, it is possible to mathematically average flow in the pipe even when the profile is not symmetrical. Later designs used 5 and 4 path criss-crossed and quadrature path configurations to average flow profile disturbances.

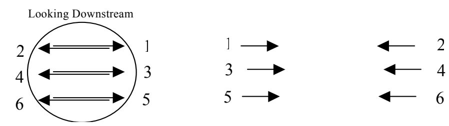

Figure 3: Layout of Paths Used in the USZ-08-6P Flowmeter

The intention of these multipath designs was to eliminate the need for a flow conditioner to change a disturbed flow profile into a normal profile. However, in practice most new installations today include a flow conditioner unless there is a very long straight run of pipe ahead of the meter installation point.

More recently, a two-path design with integral flow conditioner has been commercialized and calibrated with excellent results (Figure 5). In this design, the flow conditioner is located 10 diameters upstream of the meter body (Figure 4). The idea behind this design is, as stated, most new installations include a flow conditioner to assure a symmetrical flow profile at the measurement point. Together with a flow conditioner of the proper design, only two paths are needed to achieve or exceed AGA-9 accuracy specifications in most situations when the meter is properly installed. Reducing the number of paths to two simplifies the design and reduces the total number of components needed, further reducing cost of ownership.

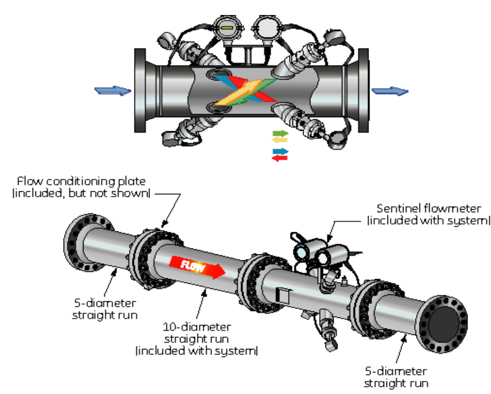

Figure 4: Sentinel 2-Path Meter shown with complete meter run

American Gas Association Transmission Measurement Committee Report No. 9

In recent years, ultrasonic flow meters have taken a prominent position along with differential pressure and turbine flow meters for natural gas custody transfer measurement. The first prototype ultrasonic meters did not have the accuracy needed for custody transfer applications. Later advancements in electronic hardware, signal processing and transducer technology gave ultrasonic flow meters the accuracy needed to meet the American Gas Association and industry requirements for fiscal metering. The use of ultrasonic meters to measure natural gas flows became widespread in the United States upon the approval of AGA-9 by the American Gas Association. AGA-9 is a report that specifies criteria to be followed when using ultrasonic flow meters to measure the flow of natural gas in custody transfer applications. AGA-9 was originally published in 1998. It is currently under revision to take the latest developments into account.

AGA-9 guidelines for custody transfer natural gas flow meters indicate that the meters are to be flow calibrated, preferably to a National Standard such as NIST. The calibration should include the upstream straight piping and flow conditioning that form part of the meter. In addition there are requirements for inside pipe smoothness to help ensure uniform flow, and even a specification for any mismatch (<1%) in internal diameter between the flow meter and the calibration facility piping.

Multipath ultrasonic meter performance has improved to the point that their calibrations will normally exceed the accuracy requirements of AGA-9 (0.7% for 12" and larger pipe). It is not uncommon or surprising for users to request accuracies better than the AGA-9 criteria.

An example of a recent 12" two path meter calibration is shown below in Figure 5. It illustrates the accuracy level that is attainable. Demonstrated accuracy or this meter is well within the AGA-9 specification over the entire calibration range.

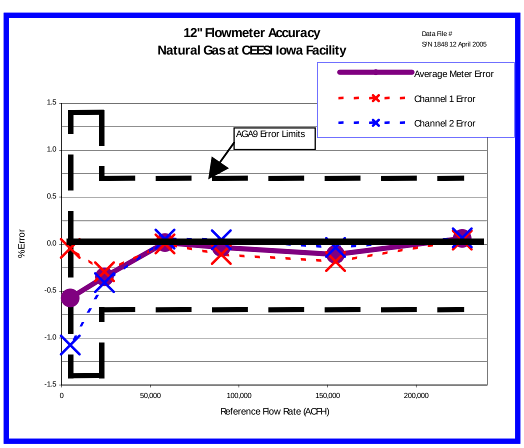

Figure 5: Calibration results of 2-path meter at CEESI

Installation Recommendations and Considerations

Upstream and downstream disturbances, such as pipe elbows and tees, may have a detrimental effect on the performance of an ultrasonic flow meter even when a flow conditioner is used, and even if the meter has multiple ultrasonic paths. The general recommendation is to be sure there are at least twenty (20) pipe diameters of straight uninterrupted pipe run upstream of the flow meter, and at least ten (10) pipe diameters of straight, uninterrupted pipe run downstream of the meter.

Under certain circumstances, sonic and ultrasonic pipe and valve noise in the flow system can cause interference with the ultrasonic transducers. Occurrences of noise interference are rare because transducers are typically designed to operate outside of the nominal noise frequencies. If there is doubt, an analysis should be performed by the system designer prior to meter selection. Consult with the flow meter manufacturer to select the appropriate transducer frequencies to avoid any potential problems.

Most flow meters have a display which shows flow parameters, most notably would be current flow rate. While a display is convenient, having at least one type of output protocol that can be connected to a plant data acquisition and control system is the preferred method of monitoring the flow rate and meter status. The most basic meter output is an analog 4 to 20 milliamp current output. A good meter will allow the user to program which parameter and its range to send through the output – usually flow rate, but in some cases other parameters are desired. Most data acquisition and control systems are set up to monitor current outputs. The second type of output is a frequency output in which a specific number of electrical pulses, similarly to current, are used to monitor a particular parameter, which again should be programmable.

The third and most powerful type is the use of digital communications. Digital communications can take many different forms, including but not limited to, RS232 or RS485 serial communications, and MODBUS. With the proper type of interface to the plant data acquisition system, any and all of the parameters monitored by the flow meter can be displayed to the plant operator. Flow meter diagnostic parameters can also be displayed to help verify proper operations of the meter and transducers. Some type of alarm relays should also be included with the flow meter electronics to provide yet another method of ensuring the meter is fully operational.

Another consideration when selecting a flow meter is the environment in which the meter will be installed. The typical classification for meters used in North America is Class 1, Division 1. Many natural gas facilities fall into the hazardous area category, and the meter must be properly certified in order to operate safely in such an environment.

The metered fluid properties and ambient conditions must also be matched to the meter to be used. Some meters cannot be used with extremely hot gases, as the temperature can degrade the transducers or even the meter body itself. The same can be said about the exterior of the meter – the meter electronics need to be robust enough to continue to operate without problems if the meter is installed in a very hot environment (under the blazing sun all day long), or in a very cold environment (continuous snow in the winter time).

Clamp-on Flow Measurement for Natural Gas

The clamp-on form of ultrasonic transit-time requires a pair of matched ultrasonic transducers, which are clamped to the outside surface of the pipe or conduit, at a prescribed axial spacing. This non-invasive version of the transit-time ultrasonic meter, in both fixed and portable form, has proved to be the most popular for liquid applications for many years. Obviously such a flow meter can be installed with no process shutdown or pipe modifications, it creates no pressure loss, nor source of leak or contamination, and whilst installation costs are minimal, maintenance is all but non-existent. Until the commercial launch in 2001, of the first clamp-on ultrasonic flow meter for gases, the Panametrics GC868, it was generally thought that this flow metering technology with all the benefits it offers, would be limited eternally to liquid measurement, due to the severe technical obstacles inherent when applying it to gas flows.

By 2005, continued advances in both clamp-on transducer design and flow meter signal processing have been made, and we have seen the technology applied successfully to the measurement of natural gas flow in a variety of applications, from offshore production to transmission and distribution. A portable version of the meter, the PT878GC, became available in late 2004, and this has enabled flow survey work to be carried out. Pipes and tubes as small as 0.75-inch, to lines of up to 30-inch have been monitored, and pressures as low as 87-psig in metal pipe have proven sufficient for successful measurement. In all respects then, the user benefits of clamp-on have been successfully transferred from the liquid world to the gas world, indeed delivering the same typical 2% of reading performance, as proven through third-party calibrations, and perhaps more significantly, through validated field work. Examples of such installations are described herein.

The North Sea oil & gas reservoirs consist of a proportionally large amount of gas. Because natural gas is lower in monetary value than oil, the production of natural gas varies with its market price. The market price of natural gas, and thus its production, fluctuates with the seasons, while oil production is generally at a constant rate. Quite a number of wells are mature and losing pressure. Rather than exporting all natural gas produced, a percentage of natural gas is re-compressed after processing and re-injected to wells both as a driving force for oil production and as a natural storage for future deliveries. Incoming multiphase flow and export flows are already measured, and the final measured flow parameter in the mass balance is the flow of re-injected gas.

The re-injected gas keeps well pressure up for enhanced oil production and acts as a carrier for residual oil when retransferred to the surface. For injection gas and separator gas measurement the use of a DP cell with Orifice or V-cone meter has traditionally been the most commonly selected instrumentation. These require flanged pipe connections, which under the stated conditions would raise serious issues of safety, security and maintenance. As this is a process control measurement, the accuracy specification is acceptable within +/- 3 to 5 % of the reading. A series of four separate flow comparisons were made over a total of 4.5 hours, including a short period of zero flow, and the deviation between the GC868 and the in-line DP device was 1.3% to 2.3% of reading across the tests.

It has also been found that clamp-on ultrasonic gas flow meters can be used successfully on bi-directional lines as required for subterranean storage of natural gas. The gas involved will vary in pressure significantly between import and export scenarios. For on-shore storage applications, typically involving man-made salt caverns, the gas will be wet and often contaminated with Methanol and sulfur deposits. For offshore situations, the gas will typically also carry sand. Conventional flow metering technologies are unable to function bi-directionally, nor withstand the contamination and erosion. The clamp-on technology has proven able to function reliably in these applications. In one example in the UK (see Figure 6), agreement with an in-line multi-path ultrasonic meter of custody transfer standard was seen to better than 1.75% of reading in all but the lowest flow rate where it was recorded at 2.41%. The technology provides storage well management and, in the offshore case, protection against damage by sand erosion to vital downstream controls at high flows.

Figure 6: Clamp-on flow meter on natural gas at 100-psig inside large manufacturing plant

Transmission of natural gas consumes a great deal of energy in compressor operation as the gas is moved around the landmass. Indeed, it is calculated that gas transmission companies are their own biggest “customer.”

Compressor efficiency is thus important, and the clamp-on technology allows rapid temporary monitoring of this parameter at remote locations with minimum cost and no system disruption.

The Future

The ultrasonic flow meter is the fastest growing flow meter type at present. Its inherent advantages make it a popular choice among the various flow meter technologies available to instrument and process engineers. Use of ultrasonic flow meters will continue to grow as users continue to become familiar with the technology and achieve success with its use. For natural gas measurement, the use of ultrasonic meters will continue to expand globally.

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