Selecting flowmeters for natural gas

Different parts of the natural gas delivery chain require different instruments, such as differential pressure (DP), ultrasonic, and Coriolis flowmeters.

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During the last few years, there has been a tremendous increase in U.S. production of natural gas, much of it derived from fracking plays. According to the federal Energy Information Administration (EIA), dry natural gas shipments increased from 1 trillion ft3 in 2000 to 5 trillion ft3 in 2010, and production increased by a factor of 12 in one decade's time. EIA predicts that by 2035, shale gas will account for nearly half of all U.S. gas production (see Figure 1).

Flow measurement is critical at all points of the supply chain. Both fiscal and custody transfer measurements are needed in many of these points, but the appropriate instruments to make those measurements vary.

Fiscal measurement versus custody transfer

Custody transfer is one of two forms of fiscal measurement. The other is allocation, defined as "the transfer of goods between two points generally not governed by a buy/sell contract," while custody transfer is done under a contractual obligation between buyer and seller that may require adherence to accuracy, repeatability, linearity, or uncertainty standards defined by measurement standards such as American Gas Association (AGA), American Petroleum Institute (API), International Organization for Standardization (ISO), GOST (Russian equivalent to API), and so on.

All forms of fiscal measurement can be affected by product quality, fluid properties and composition, operating parameters, maintenance practices, and technology type.

While gas custody-transfer flow measurement can take place anywhere along the process value chain from the wellhead to delivery or sale location, for the lowest uncertainty in measurement, it generally takes place at stable, predictable single-phase locations or physically discrete hand-over points (e.g., platform/production exit location, pipeline entry/exit, terminal entry, etc.). These locations generally provide the favorable conditions in which most flow measurement devices can operate with some degree of predictability and repeatability.

Penalties for uncertainty in fiscal measurement

The enormous value of gas involved makes accuracy essential. At current gas prices, an error of 1% in measuring 300 million ft3 of gas per day can lead to a difference of about $2 million per year (see Figure 2).

Available technologies

Here, three technologies: differential pressure (DP), ultrasonic (both of which measure volumetric flow), and Coriolis, which directly measures mass flow are discussed. Simple volumetric flow measurement technology is not the only consideration because the ultimate measurement—and what the customer pays for—is energy delivered. For this reason, accurate and repeatable measurement of natural gas flow requires simultaneous measurement of several other variables, including pressure, temperature, density, and gas composition.

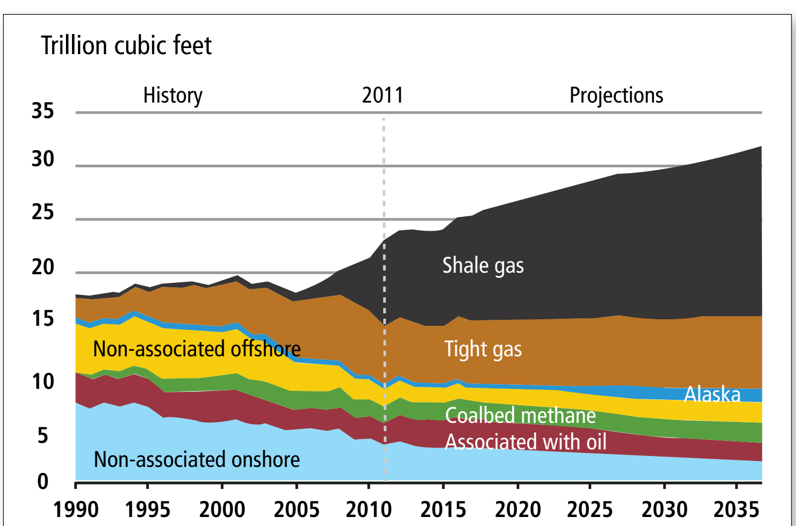


Figure 1: The Federal Energy Information Agency predicts that by 2035, shale gas will account for nearly half of all U.S. gas production. Courtesy: Federal Energy Information Agency

DP meters

DP meters measure volumetric flow through a calibrated orifice (generally a flow plate), are inexpensive, and simple in concept. They are accepted broadly and are not limited in line size. While not the most accurate instruments available, they are acceptable for the purposes for which they are used, and the calculations for correcting to standard conditions are widely known.

DP meters measure only differential head. To measure either mass or volumetric flow, they must be corrected for density (mass) or temperature, pressure, and gas composition to obtain a standard reading. They have low turndown unless the orifice plate is changed. In addition, they are subject to fouling, which can partially obstruct the orifice plate and cause the meter to read high. The only way to counter fouling in a DP meter is to send someone out periodically to inspect the orifice plate, which is expensive in terms of labor and can mean an interruption in production. In addition, DP meters are sensitive to flow profile and require either a fairly long straight run or an upstream flow conditioner. They also generate a medium-to-large pressure loss, and they are not as accurate as other technologies, such as gas turbine, ultrasonic, or Coriolis meters. The use of DP meters for custody transfer is governed by API 14.3/AGA3 in North America and ISO 5167 globally.

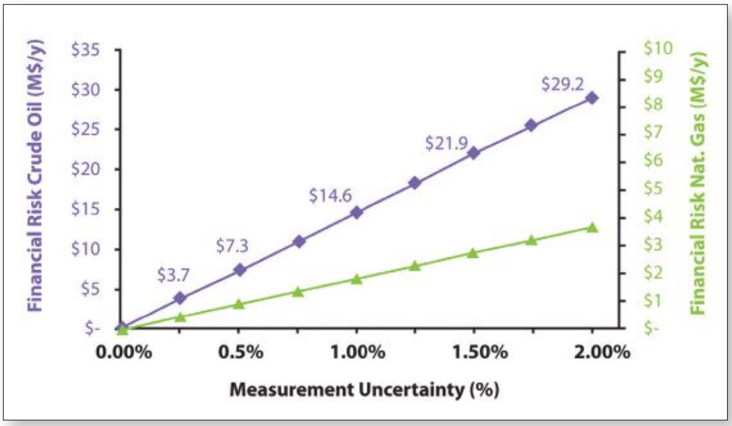
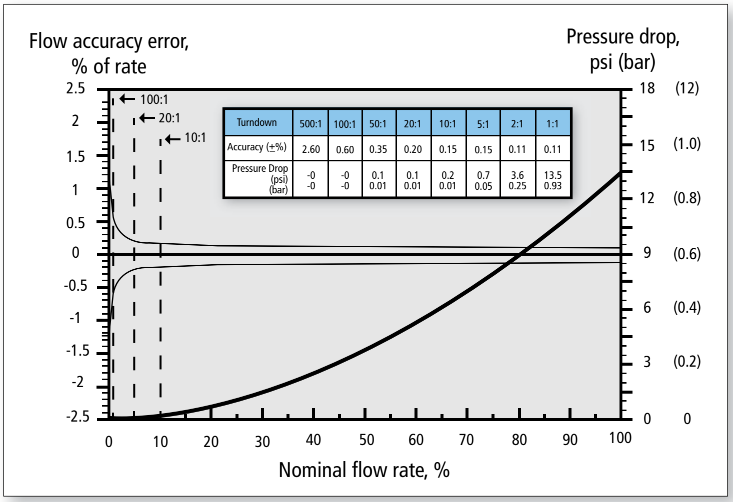


Figure 2: This graph shows financial risk versus measurement uncertainty. Courtesy: Emerson Process Management



Turndown	500:1	100:1	50:1	20:1	10:1	5:1	2:1	1:1
Accuracy (±%)	2.60	0.60	0.35	0.20	0.15	0.15	0.11	0.11
Pressure Drop (psi) (bar)	-0 -0	-0 -0	0.1 0.01	0.1 0.01	0.2 0.01	0.7 0.05	3.6 0.25	13.5 0.93

Figure 3: The pressure drop associated with a Coriolis meter tends to restrict its use to smaller line sizes. Courtesy: Emerson Process Management

Coriolis meters

Coriolis flowmeters measure mass flow and density directly. They do not need pressure and temperature compensation for fluid properties. They feature wide turndown ratios and do not experience performance or calibration drift. They work well where product density is not stable, such as, for example, critical-phase ethylene. Unlike DP and ultrasonic meters, they do not require flow conditioning. In addition, most Coriolis meters are available with self-diagnostics that can detect when they are beginning to foul (they exhibit a change in baseline frequency response) without having to send someone out to open and examine the meter. In addition, a Coriolis meter can detect the onset of two-phase flow.

Coriolis meters are physically large, relatively expensive, and produce pressure drop (see Figure 3). In addition, they generally are not available in sizes larger than 16 in. (and, in fact, are often one or two pipe sizes smaller than the lines in which they are installed, which contributes to pressure drop). For this reason, they are generally restricted to applications in which pressure drop is of limited concern.

It's interesting to note that while a Coriolis meter will give a density reading, in many markets, much of the accounting is done in terms of standard volume, which means it is still necessary to measure temperature and pressure, as well as gas composition. The use of Coriolis meters for custody transfer is governed by AGA-11.

Ultrasonic meters

Ultrasonic flowmeters measure volumetric flow rates. Advantages include standard volume flow accuracy of 0.35% to 0.5%, with 0.25% available, as well as negligible pressure drop and high turndown capability. The high turndown makes them useable in applications subject to wide variations in flow, which means that a single ultrasonic meter can replace multiple other meters (see Figure 4).

Limitations of ultrasonic meters include the need for sufficient straight-run upstream or a flow conditioner. Because the accuracy of an ultrasonic meter depends on the accuracy with which the flow profile inside the instrument is known, ultrasonic meters for custody transfer applications generally use a minimum of four paths. A number of six-path and eight-path meters have been introduced, but research (Klaus Zanker, Letton Hall Group, and Tom Mooney, Emerson Process Management [now with BP]), "Limits on Achieving Improved Performance from Gas Ultrasonic Meters and Possible Solutions," presented at the 30th International North Sea Flow Measurement Workshop, Oct. 23-26, 2012) has shown that little is gained by exceeding four paths.

There are meters with more than four paths. However, the additional paths usually are provided as a separate flowmeter within the same flowmeter body as a means of checking the overall operation of the meter (see Figure 5). There is, in fact, an eight-path meter available that is essentially a pair of four-path meters in a redundant configuration.

Figure 4: This photo shows an ultrasonic meter installed in a natural gas field. Courtesy: Emerson Process Management

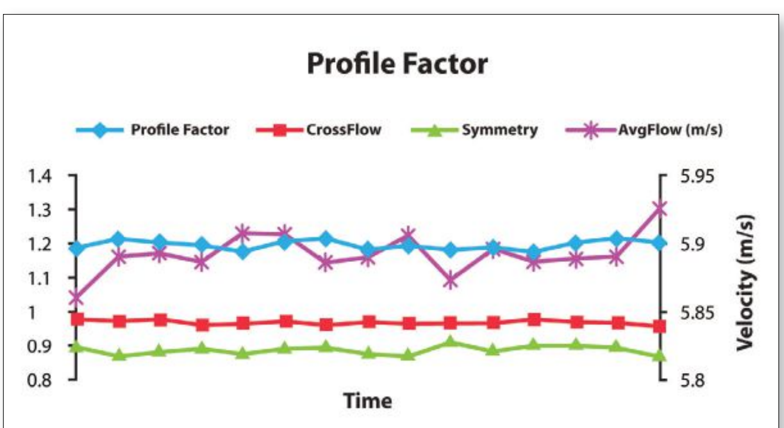


Figure 5: Ultrasonic meters with four paths or more can detect critical flow disturbances to significantly minimize measurement uncertainty. Courtesy: Emerson Process Management

An important feature of many ultrasonic meters is their built-in diagnostics, which enable them to detect the presence of liquids (two-phase flow), dirt buildup, blockage, and other problems. And because they measure speed of sound in the gas, they can help provide a sanity check on other instruments, such as gas chromatographs, and check the accuracy of mathematical conversion to standard pressure elsewhere in the system. The ultrasonic meter constantly measures the speed of sound in the flowing gas. The unit's built-in flow computer functionality also can calculate the speed of sound based on input data from pressure and temperature transmitters and a gas chromatograph (GC). Any disagreement between the computed and measured values indicates a problem somewhere in the system.

An ultrasonic meter is very effective at detecting two-phase flow; the presence of liquids generally indicates a problem elsewhere in the system (or that the ultrasonic meter has been installed at the wrong location). The sudden appearance of liquids can indicate a problem with the separation equipment upstream of gas processing, while any ethanes or propanes that condense out of the natural gas flow downstream of gas processing are products that should have been separated for sale as liquids and indicate process issues with the gas processing plant. The use of ultrasonic meters for custody transfer is governed by AGA-9 and ISO/DIS 17089-1 (see Figure 6).

Flow computers

Flow computers measure, monitor, and may provide control of gas flow for all types of meters. They usually are mandatory for custody transfer applications. The flow computer receives volumetric flow measurement data from DP or ultrasonic gas meters, along with temperature and pressure, and calculates the flow rate. To calculate the energy flow, the flow computer needs information on gas composition (percentage of methane and heavy hydrocarbons, as well as any nitrogen and carbon dioxide) and density. Because a Coriolis meter measures mass flow directly, much of the calculation can be done by a flow computer built into that instrument.

The flow computer also acts as a record keeper recording date and time, instantaneous, hourly, and daily data. It stores date/time-stamped volume records in memory long enough for a host system to retrieve the records as well as to allow time for human intervention if this retrieval fails to occur.

Shale gas is different

It's important to note that shale gas, which is what is fueling the transformation of the energy industry, is different from conventional natural gas in several important ways. First, it may contain less than 50% methane, compared to 85% for conventional gas. The rest generally is heavy hydrocarbons: ethane, propane, butane, iso- and normal-pentane, etc. And because shale gas wells are switched in and out, that composition can change in a matter of hours. In addition, it's often accompanied by large amounts of water, CO2, H2S, and sand.

Gathering shale gas

The exact sequence of steps in shale gas recovery and separation varies somewhat from place to place, but the following description gives the general idea.

Shale gas fields generally consist of multiple wells that feed a satellite skid through fairly small diameter lines, none of which carry enough gas to justify the cost of a high-end flowmeter. DP meters are the choice here because they are simple and inexpensive. True, they can be fouled by dirt and confused by multiphase flow, but they aren't being used for fiscal measurement; rather to help the operator keep track of how the different wells are behaving to choose which ones to start and stop. As long as accuracy is reasonable, and repeatability is acceptable, a DP meter is the logical choice.

From the satellite skid, the gathered gas goes to a knockout pot or sand trap where bulk liquids and particles are removed and then to a flowmeter—generally a DP meter as well—through a 6- or 8-in. pipe. This works well as long as the system isn't pushed so hard that liquids or dirt are carried through into the flowmeter, which can reduce the orifice size and make the meter read high.

From the knockout pot, the gas flows to a dehydrator to remove water vapor and perhaps to a micro-membrane separator to remove excess CO2. Next, the gas goes to natural gas liquid separators and perhaps a debutanizer and/or an H2S separator. These generally are 8- to 10-in. lines, and a Coriolis meter or an ultrasonic gas flowmeter can be a good choice here because of their large turndowns involved.

As the gas travels along, the pipe size tends to increase, which is where ultrasonic gas meters come into their own. They are, for example, a good fit for the inputs and outputs of cryogenic gas processing plants and for feeds to large industrial users such as power plants.

As the gas moves toward delivery to users smaller than power plants or cryogenic gas plants, line sizes tend to decrease, at which point Coriolis meters begin to reappear.

While conversion of flow rates to standard volume is needed, the variability of shale gas makes it necessary to use a GC, which is the only way to be certain about the calorific value of the gas delivered. While a Coriolis meter will provide information on gas density, the GC is still needed to obtain a number for Btus per pound; a GC is expensive and tends to be reserved for places where there is enough volume to justify its cost.

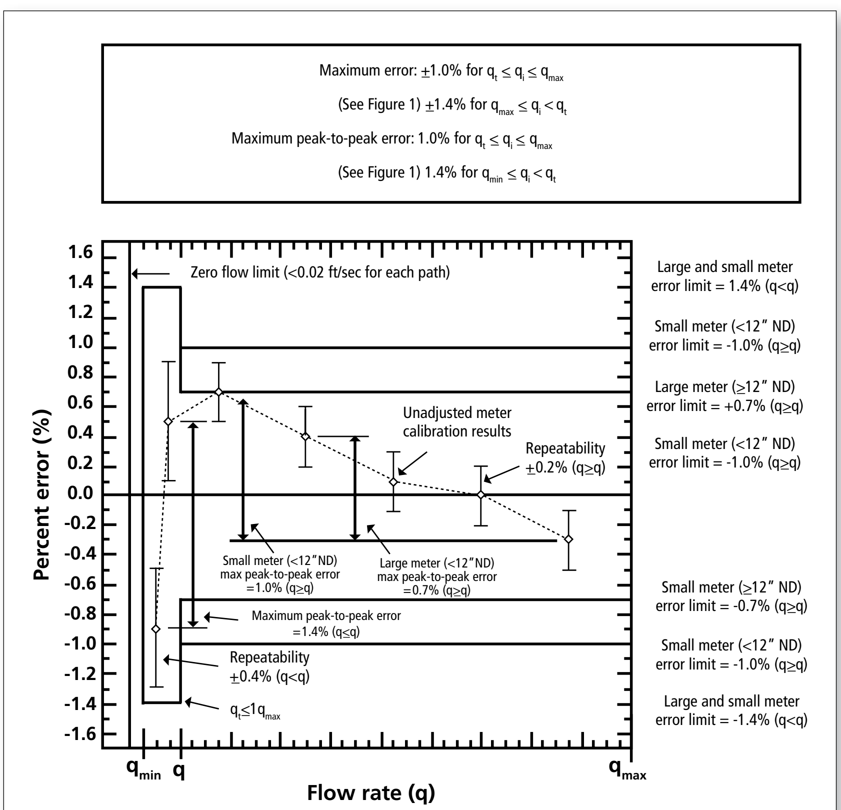


Figure 6: The use of ultrasonic meters for custody transfer is governed by AGA-9 and ISO/DIS 17089-1. Courtesy: American Gas Association

Managing challenges

Each stage in the natural gas supply chain presents its own challenges and opportunities for gas flow measurement—either fiscal or custody transfer. When choosing a flowmeter supplier, it is wise to consider a supplier that can provide as many pieces of the puzzle as possible—including multiple meter types—to gain unbiased advice on the most appropriate equipment for each step in the supply chain from the wellhead to the ultimate customers.

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