Introduction
Natural gas meter selection is based on a variety of factors: the most important of which are safety and accuracy. Other significant factors include repeatability, defensibility through adherence to contractual and/or regulatory requirements and industry standards, cost effectiveness, reliability, and uniformity with existing installations.

This paper will briefly discuss commonly used high pressure gas meters, their basic functionality, applicable standards, installation and operating considerations based on the author's experience and a review of industry standards and literature, their turndown, and specific examples of recent meter selections for specific applications.

Orifice Meters
An orifice meter is an inferential meter in which the fluid velocity and flow rate are inferred from the pressure drop occurring through the known area of an orifice plate. Specifically, orifice meter flow is calculated from the flowing gas pressure and temperature, differential pressure drop occurring across the restriction of the meter's orifice plate, the meter geometry including the meter tube's inside diameter and orifice plate bore, and the gas composition.

Orifice measurement is a mature technology. Orifice flow coefficients were published in 1903, while the first documented installation of an orifice meter with a recorder was in 1911, and the first commercially available orifice meter was offered in 1915.

Orifice meter calculations are based on Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, American Gas Association (AGA) Report No. 3, Part 3, Natural Gas Applications, 1992. Orifice meters and all subsequently described meters in this paper utilize AGA Report No. 8, Compressibility Factors of Natural Gas and Related Hydrocarbon Gases, 1994 in determining supercompressibility factors for volumetric calculations.

New orifice plate fabrication, orifice meter construction, and installation specifications are based on Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, American Gas Association (AGA) Report No. 3, Part 2, Specification and Installation Requirements, 2000. Orifice meters with inlet piping configurations adhering to the fabrication requirements described in this report can achieve an optimal uncertainty (accuracy) of +/- 0.5%. Newly constructed orifice meters are not typically calibrated or compared to a standard upon manufacture. Orifice meters are available in 2" and larger sizes. Dual chamber orifice meter fittings, which allow for orifice plate inspection without an interruption in service, are available.

Orifice meter factors and coefficients were based on laboratory tests, and orifice meter accuracy is highly dependent on meter tube and orifice plate condition. It is highly important that orifice meter tube and plate conditions be properly maintained. Application concerns and under-measurement in orifice measurement may arise from reversed (bevel directed downstream) orifice plates, two-phase flow, liquid and solids accumulations on orifice plates or in meter tubes, leaking orifice plate seal rings, blocked pressure tap gauge lines, and bowed orifice plates. Over-measurement may arise from orifice plate obstruction, pressure tap or gauge line freezes, turbulent gas flow, blocked flow conditioners, pulsation induced square root error, gauge line error (sonic resonance induced pressure tap gauge line distortion), and orifice fittings and meter tubes with mis-matched schedules. Please note: some of the aforementioned application concerns could result in under or over-measurement depending on actual field conditions.

Meter turndown or range-ability is defined as the ratio of the maximum meter capacity to the minimum meter capacity for the specified operating conditions during which the required or specified accuracy is maintained. An orifice meter’s turndown is based on 1. Beta Ratio, and 2. Differential pressure limitations:
1. The Beta ratio is the ratio of the orifice plate bore to the meter tube inside diameter. Long term operating Beta ratios are typically limited from 0.2 to 0.6 based on the area of constant uncertainty as depicted in AGA Report 3, Part 1, 1990, General Equations and Uncertainty Guidelines, Figure 1-6 – Practical Uncertainty Limits. Figure 1-6 indicates constant positive and negative uncertainty from a 0.1 to 0.6 Beta ratio with uncertainty increasing exponentially above a 0.6 Beta ratio.

An existing orifice meter tube’s lengths upstream and downstream of the orifice plate may reduce its operating Beta ratio range. An orifice meter tube’s upstream and downstream lengths should be verified for conformity with the AGA standards that were in effect at the time of its fabrication and installation. Any meter with Beta ratio operating limitations based on its upstream or downstream lengths should be clearly labeled with those limits to ensure measurement accuracy.

2. Orifice meter operating differential pressures ranges are based on a. Orifice plate mechanical differential pressure limitations and, b. Differential pressure transmitter range limitations.
   a. Orifice plate maximum differential operating pressures must be maintained below those that cause orifice plate deflection and deformation. Calculated maximum differential operating pressures based on orifice plate thickness, orifice meter type (orifice flange union or orifice fitting), and Beta ratio are shown in AGA Report 3, Part 2, 2000, Appendix 2-E.
   b. Minimum flowing differential pressures must be maintained above transmitter noise level and flow computer low differential pressure cut-off levels. Maximum differential pressure transmitter calibration ranges and subsequent operating pressure ranges may also be limited based on access to test equipment.

The following examples depict orifice meter turndown under varying conditions and illustrate that orifice meter turndown does not change with operating pressure. Orifice meter range and turndown will be represented on the basis of operation of an orifice meter with a single orifice plate and with multiple orifice plates.

Range at a constant pressure with a single orifice plate: A Schedule 80 2” orifice meter equipped with a 0 to 400” water column range differential pressure transmitter, and a single standard 1/8” increment orifice plate typically possesses a 3:1 turndown.

<table>
<thead>
<tr>
<th>Conditions</th>
<th>40” and 0.875” plate (0.451 Beta) (MSCFD)</th>
<th>360” and 0.875” plate (0.451 Beta) (MSCFD)</th>
<th>Turndown</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 PSIG at 60º F</td>
<td>338</td>
<td>979</td>
<td>3:1</td>
</tr>
<tr>
<td>500 PSIG at 60º F</td>
<td>741</td>
<td>2,205</td>
<td>3:1</td>
</tr>
</tbody>
</table>

The same meter equipped with varying standard 1/8” increment orifice plates will provide a 16:1 turndown.

<table>
<thead>
<tr>
<th>Conditions</th>
<th>40” and 0.500” plate (0.258 Beta) (MSCFD)</th>
<th>360” and 1.250” plate (0.580 Beta) (MSCFD)</th>
<th>Turndown</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 PSIG at 60º F</td>
<td>108</td>
<td>1,689</td>
<td>16:1</td>
</tr>
<tr>
<td>500 PSIG at 60º F</td>
<td>236</td>
<td>3,811</td>
<td>16:1</td>
</tr>
</tbody>
</table>

**Turbine Meters**

A turbine meter is an inferential meter in which the fluid velocity and flowrate through the known open area of the meter or "throat" are inferred from the turbine rotor speed and total revolutions. Specifically, turbine meter flow is calculated from the flowing gas pressure and temperature, the turbine rotor speed, and the gas composition. Total rotor revolutions may be indicated by an attached mechanical index or an electric output.
Gas turbine meters were introduced into the United States market in the early 1960’s and their application has continually increased in settings where a high turndown is required.

Turbine meter calculations are based on AGA 7, Measurement of Gas by Turbine Meters, 2006.

Turbinometer performance and installation guidelines are contained in AGA 7 Measurement of Gas by Turbine Meters, 2006. The standard provides installation guidelines for various turbine meter body designs (in-line, in-line with integral straightening vanes, and angle-bodied), and meter inlet and outlet piping configurations based on meter body design and desired meter tube footprint. Turbine meter accuracy is generally +/- 1.0% of reading. As a standard, manufacturers typically perform low pressure or atmospheric air meter calibrations, but purchasers may specify higher pressure calibrations. Accuracies of +/- 0.5% are achieved within limited portions of a turbine meter’s flow range. Turbine meters are available in 1” and larger sizes. Turbine meters are designed for a maximum flow rate so as not to exceed a certain maximum rotor speed in RPM. The minimum flow rate for a turbine meter is the lowest flow rate at which the meter will operate within its specified accuracy.

Turbine meter accuracy is highly dependent on turbine rotor and bearing condition and gas flow characteristics. Application concerns and under-measurement may arise from rotor and rotor bearing damage resulting from inadequate upstream filtration and lack of rotor bearing lubrication maintenance. Shock loading and excess flow may also cause rotor damage, so care should be taken in the sizing and location of associated regulators, relief valves, and control valves. Restricting orifices or nozzles may be installed to limit flow, and their resulting pressure loss should be taken into consideration. Reverse operation and over-speed resulting from meter tube blowdowns may damage a turbine meter requiring that meter tube blowdowns be located downstream of the meter and sized to prevent rapid depressurization. Over-measurement may arise from pulsating or rapidly fluctuating flows as a turbine meter’s rotor will accelerate in response to rapid flow increases more readily than it will decelerate with decreasing flows. Turbine meter sites should be equipped with parallel full capacity meters or be equipped with a bypass to allow servicing and repair of meters. Also, the author’s experience indicates that turbine meters connected to electronic flow measurement should always be equipped with a mechanical index as a backup.

Turbine meter turndown increases with increasing pressure due to the increased kinetic energy transfer to the turbine rotor at lower gas velocities. The below example’s flowrates are based on a 2” body turbine meter operating at 100 and 500 PSIG.

<table>
<thead>
<tr>
<th>Conditions</th>
<th>Minimum Flowrate (SCFH)</th>
<th>Maximum Flowrate (SCFH)</th>
<th>Turndown</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 PSIG at 60° F</td>
<td>1,395</td>
<td>27,261</td>
<td>20:1</td>
</tr>
<tr>
<td>500 PSIG at 60° F</td>
<td>2,956</td>
<td>122,305</td>
<td>41:1</td>
</tr>
</tbody>
</table>

**Rotary Meters**

A rotary meter is a positive displacement meter in which gas flow is measured as volume is swept through counter-rotating rotors in a chamber of known volume, and the rotor revolutions are indicated by a magnetic or mechanical drive. Specifically, rotary meter flow is calculated from the flowing gas pressure and temperature, the number of rotor revolutions, and the gas composition.

Rotary meters were first manufactured in 1920 by the PH & FM Roots Company and see wide use in distribution and transmission settings.

Rotary meter calculations are based on AGA 7, Measurement of Gas by Turbine Meters, 2006.

Rotary meter design and installation standards are based on ANSI B109.3 - Rotary-Type Gas Displacement Meters, Approved April 13, 2000. Rotary meters are typically available in sizes of 1-1/2" and larger.

Per ANSI B109.3, an initial rotary meter accuracy of +/- 1.0% for flowrates approximately 10% to 100% of the meter’s rated capacity is required. Additional specified calibrations can yield accuracies of less than +/- 0.5% of reading.
Rotary and turbine meters share identical installation and operational concerns in the area of upstream filtration, lubrication maintenance, and rotor speeds. Inlet debris may cause a rotary meter to lock up and block flow. Some manufacturer's meters are equipped with a pressure-differential triggered internal bypass to allow unmeasured flow in the event of rotor blockage to provide for continuity of service. In rotary meters, under-measurement typically occurs at lower flowrates. Rotary meters require a minimum flow to start measuring, but will often continue to measure lower flows after starting. Also, operation at extremely low flowrates for extended periods may cause inadequate splash lubrication resulting in bearing and internal component wear. As in a turbine meter, if a rotary meter's maximum capacity is exceeded continuously, damage may occur. Typically, a rotary meter can withstand a flowrate 20% over its stated maximum for short periods. Most manufacturers state that under-measurement occurring at low flowrates is balanced by slight over-measurement at medium to high flowrates.

Rotary meter turndown does not change with operating pressure. However, minimum measured volumes do increase with increasing operating pressure. The below example’s flowrates are based on a 2” body high pressure rotary meter operating at 100 and 500 PSIG.

<table>
<thead>
<tr>
<th>Conditions</th>
<th>Minimum flowrate (SCFH)</th>
<th>Maximum flowrate (SCFH)</th>
<th>Turndown</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 PSIG at 60º F</td>
<td>584</td>
<td>19,472</td>
<td>33:1</td>
</tr>
<tr>
<td>500 PSIG at 60º F</td>
<td>2,621</td>
<td>87,361</td>
<td>33:1</td>
</tr>
</tbody>
</table>

**Ultrasonic Meters**

An ultrasonic meter measures gas velocity by measuring the transit times of ultrasonic pulses sent between two transducers in the gas flow direction and against the gas flow direction. Custody transfer ultrasonic meters typically contain multiple pairs of transducers. Gas velocity and flowrate are then calculated using the transit time differences, gas composition, gas temperature, gas pressure, and meter geometry (path length between transducer pairs).

The original patent for an ultrasonic meter was issued in 1928, and development of the meter continued from the 1950’s through the 1980’s. The application of ultrasonic meters has increased steadily since the 1990’s.

Ultrasonic meter calculations are based on AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters, 1998, and AGA Report No. 10, Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases.

Ultrasonic meter design, functionality, and installation standards are based on AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters, 1998. AGA 9, Appendix C provides installation recommendations, but generally, meter manufacturer’s specific recommended practices should be followed for installations. Most manufacturers recommend the use of an upstream flow conditioner in accordance with the flow conditioner manufacturer’s installation guidelines. Ultrasonic meters are available in sizes of 2” and larger.

Typical ultrasonic meter accuracy is +/- 0.5% without laboratory flow-calibration. Laboratory flow-calibration and calibration-factor adjustment, although, not required by AGA 9, can yield accuracies of +/- 0.2%. AGA 9 requires pre-calibration-factor adjustment accuracies of +/- 0.7% for meters 12” in diameter and larger and +/- 1.0% for meters less than 12” and smaller. AGA 9, Appendix A provides details on flow-calibration. Ultrasonic meters provide accurate bi-directional measurement if provided with proper flow conditioning.

Ultrasonic meter accuracy is affected by flow conditioning, excessive gas velocity, ultrasonic noise from control valves and regulators, stray AC currents, and contamination by liquids and solids. Installation effects (upstream piping configurations and their resulting affects on flow conditioning) do affect ultrasonic meter performance, but use of a flow conditioner in accordance with manufacturer’s guidelines will generally yield performance within AGA 9 guidelines. Meter manufacturers generally prescribe maximum velocities of 100 to 110 feet per second while typical pipeline velocities range from 30 to 60 feet per second. Higher meter velocities can result in a loss of measurement, erosion of internal components, and higher pressure drop across upstream flow conditioners which might create audible and ultrasonic noise. Ultrasonic noise from upstream and downstream control valves,
regulators, or other sources impedes an ultrasonic meter’s ability to communicate from transducer to transducer and can result in mis-measurement. Some installation designers provide “noise traps” consisting of multiple dead-end tees or provide spacing between a noise source and a meter to attenuate the noise. Stray AC current may generate random errors in an ultrasonic measurement application. Generally, care in isolation and grounding of components and piping will remedy the effects of stray AC current. Ultrasonic meters have no moving parts and their internal components do not protrude significantly into the gas stream, however, accumulations of solids or sludge will affect their performance, and accumulation of liquids in a meter may cause false low-flow indications. Also, solid accumulations or blockages occurring in upstream flow conditioners can affect flow conditioning and meter performance. Ultrasonic meters require an external power supply for operation.

Ultrasonic meter turndown does not change with operating pressure. However, minimum measured volumes do increase with increasing operating pressure. The below example’s flowrates are based on a 4” body ultrasonic meter operating at 100 and 500 PSIG. The reader will note that the below example’s turndown is directly proportional to the ratio of the maximum to minimum velocities. Also, the below example utilizes conservative minimum and maximum flow velocities: use of a wider range of flow velocities results in a higher turndown.

<table>
<thead>
<tr>
<th>Conditions</th>
<th>Minimum flowrate at 5 FPS (MSCFD)</th>
<th>Maximum flowrate at 80 FPS (MSCFD)</th>
<th>Turndown</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 PSIG at 60º F</td>
<td>299</td>
<td>4,784</td>
<td>16:1</td>
</tr>
<tr>
<td>500 PSIG at 60º F</td>
<td>1,419</td>
<td>22,075</td>
<td>16:1</td>
</tr>
</tbody>
</table>

**Coriolis Meters**

Coriolis force is the inertial force of a particle (or fluid stream) acting on the interior of a rotating body as the particle moves toward or away from the center of rotation. Coriolis meters measure mass flowrate by sensing the Coriolis force applied by the fluid stream as it flows through a single oscillating tube or pair of oscillating tubes. Volumetric flow is determined by dividing the fluid mass flowrate by the measured fluid’s density. Coriolis flow measurement is not sensitive to pressure and temperature.

AGA Report No. 11, Measurement of Natural Gas by Coriolis Meters provides performance-based specification and test methods for Coriolis meters.

Coriolis meters have been utilized for liquid measurement since the 1980’s and refinements made during the 1990’s have lead to increasing gas measurement applications.

AGA 11 specifies an accuracy of +/- 1.0%. Some vendor specifications state an accuracy of +/- 0.5% or better on gases.

Coriolis meters are bi-directional, are immune to pulsation, are not affected by installation orientation, can withstand service temperatures up to 400º F, are not dependent on a velocity profile, and thus do not require flow conditioning. Coriolis meters are available in sizes up to 10”, and require a minimum of piping and external equipment. Coriolis meters require an external power supply and a specific transmitter for operation.

A Coriolis meter’s minimum flowrate is based on its inherent error occurring at an actual flowrate of zero. The presence of the zero flow error indicates that meter accuracy increases as flowrate increases where the zero flow error becomes a smaller percentage of the indicated reading. A maximum flowrate is typically based on a maximum gas velocity with some units allowing a maximum gas velocity of 200 feet per second. However, most designers size a Coriolis meter based on its pressure drop at maximum flow. Coriolis meter turndown for gas applications is typically stated as 50:1 but testing has indicated turndowns of up to 150:1.

**Diaphragm Meters**

Diaphragm meters fall outside of the scope of this paper due to their general lack of high operating pressure capability. However, there are packagers that can provide high pressure cased diaphragm meters.
For the reader’s reference, diaphragm meters standards are contained in ANSI B109.1 - ’00 for Diaphragm-Type Gas Displacement Meters (Under 500 Cubic Feet per Hour Capacity) and ANSI B109.2 - ’00 for Diaphragm-Type Gas Displacement Meters (500 Cubic Feet Per Hour Capacity and Over).

Diaphragm meters have been in use since 1843 and can possess ranges from a pilot load to the meter’s maximum stated capacity.

**Meter Selection**

Selecting and sizing a natural gas meter for a new facility requires a clear understanding of the load and service conditions. In regards to sizing meters, good measurement practices and economics should guide a designer to select the smallest meter possible to provide accurate measurement of minimum flows, the smallest meter footprint, and minimized costs. The below questions should be asked and could be included in an information gathering form for designing and estimating new facilities.

- What are the pertinent pressures?
  - station design pressure (and resulting minimum meter pressure rating)
  - minimum station inlet pressure
  - maximum station inlet pressure
  - minimum delivery/receipt pressure
  - maximum delivery/receipt pressure
- What are the load’s characteristics?
  - minimum hourly flow
  - maximum hourly flow
  - minimum daily flow
  - maximum daily flow
  - Will a stated daily load be flowed in a shorter time frame of say, eight or 16 hours?
  - Will the load increase in the future?
  - Is the total load comprised of multiple smaller loads? If so, will all of the loads flow simultaneously?
  - Will usage be extremely low on weekends?
  - What are the flow characteristics of the large loads? How do they cycle on and off?
  - Will sizing a meter for the largest load result in inaccurate or no measurement of a smaller associated load?
- What is the allowable space?
- Are there noise concerns?
- Does the load or meter type require filtration?
- What will be the maximum and minimum gas temperatures at the delivery point?
- What method of gas quality determination will be used?
- Will the gas be of pipeline or wellhead quality?
- Will the customer share signals or install check measurement equipment?

As a note, other questions not related to meter selection pertaining to responsibilities for odorization, overpressure protection, provision of instrument supply gas, line heater fuel gas, and the required failure mode of regulation or flow control equipment should also be asked.

**Meter Selection Examples**

The following examples are based on actual recent projects in gathering and transmission settings.

**Example #1**: A remote wellhead receipt meter is required. The site will flow a steady 100 MSCFD of water vapor saturated gas at 110 to 130 PSIG and 70º F. Flows are expected to decline. The customer will operate production equipment including a separator immediately upstream of the meter.

Initially, given the gas quality and concerns related to the installation and maintenance costs of filtration, rotary and turbine meters were excluded from the selection. Also, given the minimal flowrate and assumed project economics for the site’s gathering service, the use of ultrasonic and Coriolis meters are excluded.
An AGA sizing program indicates that under the site’s flowing conditions, a 2” orifice meter with a 0.375” orifice plate operating at approximately 100” water column differential will accommodate the flow and will allow for continued accurate measurement as the wellhead flow declines. The 2” orifice meter was selected and installed.

In accordance with the above described application concerns for orifice meters and the customer’s responsibility for upstream separation, the customer will be counseled on the possibility of under-measurement if orifice plate inspections indicate that excessive solids or free liquids are identified.

As a note, production estimates provided by producers are often conservative, and concerns around limiting initial production have prompted some producers to disallow the use of 2” orifice meters at new installations. The use of a 3” orifice meter in the above example might result in less than optimal measurement as the site’s production declines.

Example #2: A power plant delivery is required. The site will flow 41.0 MMSCFD of pipeline quality gas at 400 PSIG and 60º F. The customer requires full filtration of the gas stream. The flow will be extremely cyclical. Typically, on start up, the flow will ramp from zero to full load in less than one hour, and shutdown will occur in a similar but reverse manner. If on-line, the load cannot be interrupted for meter inspection and maintenance.

An AGA sizing program indicates that a single 8” orifice meter would accommodate the full load, and as the load can not be interrupted, a dual-chamber meter would be required.

Further review indicated that a 6” ultrasonic meter with a minimum flowrate of 514 MSCFD at 1 foot per second and a maximum flowrate of 41.2 MMSCFD at 80 feet per second could accommodate the load. Flowrate excursions exceeding the stated 41.0 MMSCFD peak load can be accommodated by the meter’s actual range-ability to 100 feet per second and resulting 51.4 MMSCFD capacity.

The purchase and installation cost difference between the two meter types was viewed as negligible by the designer, and local operations personnel requested the use of an ultrasonic meter.

Following a full analysis of the installation costs, operational concerns, overall accuracy, and low-end measurement accuracy, the ultrasonic meter was selected and will be installed later this year.

Example #3: A distribution delivery is required. The site will flow a peak winter load of 1,000 MSCFD and an extremely low, but unknown, minimal summer daily load. The site is situated on a pipeline with a 1,480 PSIG MAOP and an average operating pressure of 800 PSIG. The pipeline company is to provide filtration and regulation and overpressure protection for the distribution company’s 90 PSIG MAOP system.

After reviewing the project, it was determined that multiple pressure cuts would be required. Also, due to capital constraints, a line heater would not be installed. Given the pressure cut from 800 PSIG to 90 PSIG, cold weather delivery temperatures will be low. To provide low flow measurement at moderate temperatures, it was decided that the meter was to be installed after the first cut regulation of 500 PSIG. After considering a high pressure cased diaphragm meter, a 2” high pressure rotary meter was selected for the service. The rotary meter was selected due to its commonality with other installations, its compact size, and its pricing. Fabrication is underway, and installation will take place later this year.

Example #4: Measurement of a 1,600 BTU/SCF processing plant stream flowing at 300º F at 640 PSIG at volumes ranging from 3.3 to 33.2 MSCFH is required.

After reviewing the temperature limitations of other meter types, a 1” Coriolis meter was selected for the service with the vendor’s assistance. The meter was installed and has been in service for approximately one year.

Conclusion
Knowledge of the functionality, operational concerns, applicable industry standards, turndown abilities of the available meter types, similar existing installations, and a thorough familiarity of the installation conditions of a new facility will ensure a safe, accurate, reliable, and cost effective meter installation.