Measurement of Gas by Multipath Ultrasonic Meters

Transmission Measurement Committee

American Gas Association

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FOREWORD

This report is published as a recommended practice and is not issued as a standard. It has been written in the form of a performance-based specification. Multipath ultrasonic meters should meet or exceed the accuracy, functional and testing requirements specified in this report and users should follow the applicable installation recommendations.

AGA Engineering Technical Note M-96-2-3, *Ultrasonic Flow Measurement for Natural Gas Applications,* is included in Appendix C, as a source of background information on ultrasonic gas metering. Contents of this technical note were based on the information available when the note was written in March 1996. Therefore, in case of any conflict between the information in the main report and the technical note (Appendix C) the content in the main report prevails.

Research test results and flow-meter calibration data have indicated that multipath ultrasonic flow meters can accurately measure gas flow rate when installed with upstream piping lengths sufficient to produce fully developed turbulent flow-velocity profiles. Various combinations of upstream fittings, valves and lengths of straight pipe can produce profile disturbances at the meter inlet that may result in flow-rate measurement errors. The amount of meter error will depend on the magnitude of the inlet velocity profile distortion produced by the upstream piping configuration and the meter's ability to compensate for this distortion. Other effects that may also result in flow-rate measurement errors for a given installation include levels of pulsation, range of operating pressures and ambient temperature conditions.

A flow calibration of each meter may be necessary to meet the accuracy requirements specified in this report. Flow-calibration guidelines are provided for occasions when a flow calibration is requested by the user to verify the meter's accuracy or to apply a calibration factor to minimize the measurement uncertainty (see Appendix A).

Unlike most traditional gas meters, multipath ultrasonic meters inherently have an embedded microprocessor system. Therefore, this report includes, by reference, a standardized set of international testing specifications applicable to electronic gas meters. These tests, summarized in Appendix B, are used to demonstrate the acceptable performance of the multipath ultrasonic meter's electronic system design under different influences and disturbances.

This report offers general criteria for the measurement of gas by multipath ultrasonic meters. It is the cumulative result of years of experience of many individuals and organizations acquainted with measuring gas flow rate. Changes to this report may become necessary from time to time. When any revisions are deemed advisable, recommendations should be forwarded to: **Operations and Engineering Section, American Gas Association, 400 North Capitol Street, NW, 4th Floor, Washington, DC 20001, U.S.A.** A form is included for that purpose at the end of this report.

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The members of the special subcommittee who devoted many hours of their valuable time and deserve special thanks and appreciation are:

Facilitator

Daniel G. Harris, Columbia Gas Transmission Corp.

Members

Edgar B. Bowles, Jr., Southwest Research Institute

Frank Brown, Duke Energy Corp.

Paul D. Ceglia, Panametrics, Inc.

Paul J. LaNasa, CPL & Associates

John Lansing, Instromet Ultrasonic Technologies, Inc.

Jeffrey L. Savidge, Gas Research Institute

John W. Stuart, Pacific Gas and Electric Co.

Kevin L. Warner, Daniel Flow Products, Inc.

James N. Witte, Tennessee Gas Pipeline Co.

Staff Executive

Ali M. Quraishi, American Gas Association

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Jeffrey M. Dowdell, CNG Transmission Corp.

Terry A. Grimley, Southwest Research Institute

Henry W. Poellnitz, III, Southern Natural Gas Co.

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Mark E. Anderson, Great Lakes Gas Transmission Co.

Philip P. Barg and Mike Rogi, NOVA Gas Transmission Ltd.

Claire Becker-Castle, Southern California Gas Co.

Jim S. Beeson, NorAm Gas Transmission

Cary Carter, Williams Gas Pipelines - Texas Gas

Thomas R. Comerford, Mercury Instruments, Inc.

Gary P. Corpron and Daniel W. Peace, Equimeter, Inc.

Glenn Dehler, formerly with TransCanada PipeLines, Ltd.

Robert D. McLean, ANR Pipeline Co.

George E. Mattingly, National Institute of Standards

Kevin M. Moir, Michigan Consolidated Gas Co.

Ronald D. Rich, Natural Gas Pipeline Co.

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AGA's Transmission Measurement Committee members represent a broad base of experience in natural gas measurement technologies. Through its committee structure, AGA provides the mechanism by which these committee members' experiences and technical expertise are used collectively to prepare industry guidelines, recommendations and reports.

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1 Introduction

1.1 Scope

This report was developed for multipath ultrasonic transit-time flow meters, typically 6″ and larger in diameter, used for the measurement of natural gas. Multipath ultrasonic meters have at least two independent pairs of measuring transducers (acoustic paths). Typical applications include measuring the flow of large volumes of gas through production facilities, transmission pipelines, storage facilities, distribution systems and large end-use customer meter sets.

1.2 Principle of Measurement

Multipath ultrasonic meters are inferential meters that derive the gas flow rate by measuring the transit times of high-frequency sound pulses. Transit times are measured for sound pulses traveling diagonally across the pipe, downstream with the gas flow and upstream against the gas flow. The difference in these transit times is related to the average gas flow velocity along the acoustic paths. Numerical calculation techniques are then used to compute the average axial gas flow velocity and the gas volume flow rate at line conditions through the meter.

The accuracy of an ultrasonic gas meter depends on several factors, such as

- precise geometry of the meter body and ultrasonic transducer locations
- the integration technique inherent in the design of the meter
- the quality of the flow profile, levels of pulsation that exist in the flowing gas stream and gas uniformity
- the accuracy of the transit-time measurements

The accuracy of the transit-time measurement depends on

- the electronic clock stability
- consistent detection of sound pulse wave reference positions
- proper compensation for signal delays of electronic components and transducers

2 Terminology

For the purposes of this report, the following definitions apply:

auditor	Representative of the operator or other interested party that audits operation of multipath ultrasonic meter.
designer	Company that designs and constructs metering facilities and purchases multipath ultrasonic meters.
inspector	Representative of the designer who visits the manufacturer's facilities for quality assurance purposes.
manufacturer	Company that designs, manufactures, sells and delivers multipath ultrasonic meters.
operator	Company that operates multipath ultrasonic meters and performs normal maintenance.
SPU	Signal Processing Unit, the portion of the multipath ultrasonic meter that is made up of the electronic microprocessor system.
UM	Multipath ultrasonic meter for measuring gas flow rates.

3 Operating Conditions

3.1 Gas Quality

The meter shall, as a minimum requirement, operate with any of the "normal range" natural gas composition mixtures specified in AGA Report No. 8. This includes relative densities between 0.554 (pure methane) and 0.87.

The manufacturer should be consulted if any of the following are expected: 1) acoustic wave attenuating carbon dioxide levels are above 10%, 2) operation near the critical density of the natural gas mixture, or 3) total sulfur level exceeds 20 grains per 100 cubic feet (320 PPM approx.), including mercaptans, H_2S and elemental sulfur compounds.

Deposits due to normal gas pipeline conditions (e.g., condensates or traces of oil mixed with mill-scale, dirt or sand) may affect the meter's accuracy by reducing the meter's cross-sectional area. Deposits may also attenuate or obstruct the ultrasonic sound waves emitted from and received by the ultrasonic transducers, and in some designs reflected by the internal wall of the meter.

3.2 Pressures

Ultrasonic transducers used in UMs require a minimum gas density (a function of pressure) to ensure acoustic coupling of the sound pulses to and from the gas. Therefore, the designer shall specify the expected minimum operating pressure as well as the maximum operating pressure.

3.3 Temperatures, Gas and Ambient

The UM should operate over a flowing gas temperature range of -13° to 131° F (-25° to 55° C). The designer shall specify the expected operating gas temperature range.

The operating ambient air temperature range should be at a minimum -13° to 131° F (-25° to 55° C). This ambient temperature range applies to the meter body with and without gas flow, field-mounted electronics, ultrasonic transducers, cabling, etc.

The manufacturer shall state the flowing gas and ambient air temperature specifications for the multipath ultrasonic meter, if they differ from the above.

3.4 Gas Flow Considerations

The flow-rate limits that can be measured by a UM are determined by the actual velocity of the flowing gas. The designer should determine the expected gas flow rates and verify that these values are within the q_{min}, q_t and q_{max} specified by the manufacturer (see Section 5.1 for definitions). The accuracy requirements for operation within q_{min}, q_t and q_{max} are stated in Sections 5.2, 5.2.1 and 5.2.2 of this report. The designer is cautioned to examine carefully the maximum velocity for noise and piping safety (erosion, thermowell vibrations, etc.) concerns.

UMs have the inherent capability of measuring flow in either direction with equal accuracy; i.e., they are bi-directional. The designer should specify if bi-directional measurement is required so that the manufacturer can properly configure the SPU parameters.

3.5 Upstream Piping and Flow Profiles

Upstream piping configurations may adversely affect the gas velocity profile entering a UM to such an extent that measurement error occurs. The magnitude of the error, if any, will be a function of the meter's ability to correctly compensate for such conditions. Research work on meter installation effects is ongoing, and the designer should consult the manufacturer and review the latest meter test results to evaluate how the accuracy of a UM may be affected by a particular piping installation configuration. Further recommendations are provided in Section 7.2.2 of this report.

4 Meter Requirements

4.1 Codes and Regulations

The meter body and all other parts, including the pressure-containing structures and external electronic components, shall be designed and constructed of materials suitable for the service conditions for which the meter is rated, and in accordance with any codes and regulations applicable to each specific meter installation, as specified by the designer.

Unless otherwise specified by the designer, the meter shall be suitable for operation in a facility subject to the U.S. Department of Transportation's (DOT) regulations in 49 C.F.R. Part 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards.*

4.2 Meter Body

4.2.1 Maximum Operating Pressure

Meters should be manufactured to meet one of the common pipeline flange classes — ANSI Class 300, 600, 900, etc. The maximum design operating pressure of the meter should be the lowest of the maximum design operating pressure of the following: meter body, flanges, transducer connections, transducer assemblies.

The required maximum operating pressure shall be determined using the applicable codes for the jurisdiction in which the meter will be operated and for the specified environmental temperature range. The designer should provide the manufacturer with information on all applicable codes for the installation site and any other requirements specific to the operator.

4.2.2 Corrosion Resistance

All wetted parts of the meter shall be manufactured of materials compatible with natural gas and related fluids.

All external parts of the meter should be made of a noncorrosive material or sealed with a corrosion-resistant coating suitable for use in atmospheres typically found in the natural gas industry, and/or as specified by the designer.

4.2.3 Meter Body Lengths and Bores

The manufacturers should publish their standard overall face-to-face length of the meter body with flanges, for each ANSI flange class and diameter. The designer, as an option, may specify a different length to match existing piping requirements.

The UM bore and the adjacent upstream pipe along with flanges should have the same inside diameter to within 1% of each other. For bi-directional applications, both ends of the meter should be considered "upstream."

4.2.4 Ultrasonic Transducer Ports

Because natural gas may contain some impurities (e.g., light oils or condensates), transducer ports should be designed in a way that reduces the possibility of liquids or solids accumulating in the transducer ports.

If specified by the designer and available from the manufacturer, the meter should be equipped with valves and necessary additional devices, mounted on the transducer ports in order to make it possible to replace the ultrasonic transducers without depressurizing the meter run. In that case, a bleed valve may be required in addition to the isolation valve to ensure that no pressure exists behind a transducer before releasing the extraction mechanism.

4.2.5 Pressure Tap

At least one pressure tap shall be provided for measuring the static pressure in the meter. Each pressure-tap hole should be between 1/8" and 3/8" nominal in diameter and cylindrical over a length at least 2.5 times the diameter of the tapping, measured from the inner wall of the meter body. The tap hole edges at the internal wall of the meter body should be free of burrs and wire edges, and have minimum rounding. For a meter body with a wall thickness less than 5/16", the hole should be 1/8" nominal in diameter.

Female pipe threads should be provided at each pressure tap for a 1/4" NPT or 1/2" NPT isolation valve. Turning radius clearance should be provided to allow a valve body to be screwed directly into the pressure tap. Pressure taps can be located at the top, left side, and/or right side of the meter body. Additional taps may provide the designer with flexibility in locating pressure transducers for maintenance access and proper drainage of gauge line condensates back into the meter body.

4.2.6 Miscellaneous

The meter should be designed in such a way that the body will not roll when resting on a smooth surface with a slope of up to 10%. This is to prevent damage to the protruding transducers and SPU when the UM is temporarily set on the ground during installation or maintenance work.

The meter should be designed to permit easy and safe handling of the meter during transportation and installation. Hoisting eyes or clearance for lifting straps should be provided.

4.2.7 Meter Body Markings

A nameplate containing the following information should be affixed to the meter body.

- the manufacturer, model number, serial number and month and year manufactured
- meter size, flange class and total weight
- internal diameter
- maximum and minimum storage temperatures
- body design code and material, and flange design code and material
- maximum operating pressure and temperature range
- maximum and minimum actual (at flowing conditions) volumetric flow rate per hour
- direction of positive or forward flow
- (optional) purchase order number, shop order number and/or user tag number

Each transducer port should be permanently marked with a unique designation for easy reference. If markings are stamped on the meter body, low-stress stamps that produce a rounded bottom impression should be used.

4.3 Ultrasonic Transducers

4.3.1 Specifications

The manufacturers should state the general specifications of their ultrasonic transducers, such as critical dimensions, maximum allowable operating pressure, operating pressure range, operating temperature range and gas composition limitations.

The manufacturer should specify the minimum operating pressure based on the ultrasonic transducer model, UM size and expected operating conditions. This minimum pressure should be marked or tagged on the UM to alert the operator's field personnel that the meter may not register flow at reduced pipeline pressures.

4.3.2 Rate of Pressure Change

Sudden depressurization of an ultrasonic transducer can cause damage if a trapped volume of gas expands inside the transducer. If necessary, clear instructions should be provided by the manufacturer for depressurization and pressurization of the meter and transducers during installation, start-up, maintenance and operation.

4.3.3 Exchange

It shall be possible to replace or relocate transducers without a significant change in meter performance. This means that after an exchange of transducers and a possible change of SPU software constants directed by the manufacturer, the resulting shift in the meter's performance shall not be outside the limits of the performance requirements specified in Sections 5.2, 5.2.1 and 5.2.2. The manufacturer should specify procedures to be used when transducers have to be exchanged, and possible mechanical, electrical or other measurements and adjustments have to be made.

4.3.4 Transducer Tests

Each transducer or pair of transducers should be tested by the manufacturer and the results documented as part of the UM's quality assurance program. Each transducer should be marked or tagged with a permanent serial number and be provided with the general transducer data listed in Section 4.3.1. If the SPU requires specific transducer characterization parameters, each transducer or transducer pair should also be provided with test documentation that contains the specific calibration test data, calibration method used and characterization parameter(s).

4.4 Electronics

4.4.1 General Requirements

The UM's electronics system, including power supplies, microcomputer, signal processing components and ultrasonic transducer excitation circuits, may be housed in one or more enclosures mounted on or next to the meter and is referred to as a Signal Processing Unit (SPU).

Optionally, a remote unit containing the power supplies and the operator interface could be installed in a nonhazardous area and connected to the SPU by multi-conductor cable.

The SPU should operate over its entire specified environmental conditions within the meter performance requirements specified in Sections 5.2, 5.2.1 and 5.2.2. It should also be possible to replace the entire SPU or change any field replacement module without a significant change in meter performance. "Significant change" is explained in Section 4.3.3.

The system should contain a watch-dog-timer function to ensure automatic restart of the SPU in the event of a program fault or lock-up.

The meter should operate from a power supply of nominal 120V AC or 240V AC at 50 or 60 Hz or from nominal 12V DC or 24V DC power supply/battery systems, as specified by the designer.

4.4.2 Output Signal Specifications

The SPU should be equipped with at least one of the following outputs.

- serial data interface; e.g., RS-232, RS-485 or equivalent
- frequency, representing flow rate at line conditions

The meter may also be equipped with an analog (4-20mA, DC) output for flow rate at line conditions.

Flow-rate signal should be scaleable up to 120% of the meter's maximum flow rate, q_{max}.

A low-flow cutoff function should be provided that sets the flow-rate output to zero when the indicated flow rate is below a minimum value (not applicable to serial data output).

Two separate flow-rate outputs and a directional state output or serial data values should be provided for bi-directional applications to facilitate the separate accumulation of volumes by the associated flow computer(s) and directional state output signal.

All outputs should be isolated from ground and have the necessary voltage protection to meet the electronics design testing requirements of Appendix B.

4.4.3 Electrical Safety Design Requirements

The design of the UM, including the SPU, should be analyzed, tested and certified by an applicable laboratory, and then each meter should be labeled as approved for operation in a National Electric Code Class I, Division 2, Group D, Hazardous Area, at a minimum. Intrinsically safe designs and explosion-proof enclosure designs are generally certified and labeled for Division 1 locations. The designer may specify the more severe Division 1 location requirement to achieve a more conservative installation design.

Cable jackets, rubber, plastic and other exposed parts should be resistant to ultraviolet light, flames, oil and grease.

4.5 Computer Programs

4.5.1 Firmware

Computer codes responsible for the control and operation of the meter should be stored in a nonvolatile memory. All flow-calculation constants and the operator-entered parameters should also be stored in nonvolatile memory.

For auditing purposes, it should be possible to verify all flow-calculation constants and parameters while the meter is in operation.

The manufacturer should maintain a record of all firmware revisions, including revision serial number, date of revision, applicable meter models, circuit board revisions and a description of changes to the firmware.

The firmware revision number, revision date, serial number and/or checksum should be available to the auditor by visual inspection of the firmware chip, display or digital communications port.

The manufacturer may offer firmware upgrades from time to time to improve the performance of the meter or add additional features. The manufacturer shall notify the operator if the firmware revision will affect the accuracy of a flow-calibrated meter.

4.5.2 Configuration and Maintenance Software

The meter should be supplied with a capability for local or remote configuring of the SPU and for monitoring the operation of the meter. As a minimum, the software should be able to display and record the following measurements: flow rate at line conditions, mean velocity, average speed of sound, speed of sound along each acoustic path and ultrasonic acoustic signal quality received by each transducer. As an option, the manufacturer can provide these software functions as part of the meter's embedded software.

4.5.3 Inspection and Auditing Functions

It should be possible for the auditor or the inspector to view and print the flow-measurement configuration parameters used by the SPU; e.g., calibration constants, meter dimensions, time averaging period and sampling rate.

Provisions should be made to prevent an accidental or undetectable alteration of those parameters that affects the performance of the meter. Suitable provisions include a sealable switch or jumper, a permanent programmable read-only memory chip or a password in the SPU.

(Optional) It should be possible for the auditor to verify that all algorithms, constants and configuration parameters being used, in any specific meter, are producing the same or better performance as when the meter design was originally flow-tested or when the specific meter was last flow-calibrated and any calibration factors were changed. The auditor may have to rely on the manufacturer for portions of this verification because of the proprietary nature of some UM algorithms.

4.5.4 Alarms

The following alarm-status outputs should be provided in the form of fail-safe, dry, relay contacts or voltage-free solid-state switches isolated from ground.

- output invalid: when the indicated flow rate at line conditions is invalid
- (optional) trouble: when any of several monitored parameters fall outside of normal operation for a significant period of time
- (optional) partial failure: when one or more of the multiple ultrasonic path results is not usable

4.5.5 Diagnostic Measurements

The manufacturer should provide the following and other diagnostic measurements via a serial data interface; e.g., RS-232, RS-485 or equivalent.

- average axial flow velocity through the meter
- flow velocity for each acoustic path (or equivalent for evaluation of the flowing velocity profile)
- speed of sound along each acoustic path
- average speed of sound
- velocity sampling interval
- averaging time interval
- percentage of accepted pulses for each acoustic path
- status and measurement quality indicators
- alarm and failure indicators

4.5.6 Engineering Units

The following units should be used for the various values associated with the UM.

Parameter	U.S. Units	SI Units
density	lb/cf	kg/m^3
energy	Btu	J
mass	lb	kg
pipe diameter	in	mm
pressure	psi or lbf/in^2	bar or Pa
temperature	°F	°C
velocity	ft/s	m/s
viscosity, absolute dynamic	lb/(ft·sec)	cP or Pa·s
volume	cf	m^3
actual (at flowing conditions) volume flow rate	acf/h	am^3/h

4.6 Documentation

Other sections of this report require documentation on accuracy, installation effects, electronics, ultrasonic transducers and zero-flow verification. The manufacturer should also provide all necessary data, certificates and documentation for a correct configuration, set-up and use of the particular meter so that it operates correctly. This includes an operator's manual, pressure test certificates, material certificates, measurement report on all geometrical parameters of the spool piece and certificates specifying the zero-flow verification parameters used. Quality-assurance documentation should be available for the inspector or the designer upon request.

The manufacturer should provide the following set of documents, at a minimum. All documentation should be dated.

a. a description of the meter, giving the technical characteristics and the principle of its operation
b. a perspective drawing or photograph of the meter
c. a nomenclature of parts with a description of constituent materials of such parts
d. an assembly drawing with identification of the component parts listed in the nomenclature
e. a dimensioned drawing
f. a drawing showing the location of verification marks and seals
g. a dimensioned drawing of metrologically important components
h. a drawing of the data plate or face plate and of the arrangements for inscriptions
i. a drawing of any auxiliary devices
j. instructions for installation, operation, periodic maintenance and trouble-shooting
k. maintenance documentation, including third-party drawings for any field-repairable components
l. a description of the electronic SPU and its arrangement, and a general description of its operation
m. a description of the available output signals and any adjustment mechanisms

n. a list of electronic interfaces and user wiring termination points with their essential characteristics
o. a description of software functions and SPU configuration parameters, including their default value and operating instructions
p. documentation that the design and construction comply with applicable safety codes and regulations
q. documentation that the meter's performance meets the requirements of Section 5, "Performance Requirements"
r. documentation that the meter's design successfully passed the tests in Appendix B, "Electronics Design Testing"
s. upstream and downstream piping configurations in minimum length that will not create an additional flow-rate measurement error of more than ± 0.3%
t. maximum allowable flow-profile disturbance, which will not create an additional flow-rate measurement error of more than ± 0.3%
u. a field verification test procedure as described in Section 8
v. a list of the documents submitted

4.6.1 After Receipt of Order

The manufacturer should furnish specific meter outline drawings, including overall flange face-to-face dimensions, inside diameter, maintenance space clearances, conduit connection points and estimated weight.

The manufacturer should provide a recommended list of spare parts.

The manufacturer should also furnish meter-specific electrical drawings that show customer wiring termination points and associated electrical schematics for all circuit components back to the first isolating component; e.g., optical isolator, relay, operational amplifier, etc. This will allow the designer to properly design the interfacing electronic circuits.

4.6.2 Before Shipment

Prior to shipment of the meter, the manufacturer should make the following available for the inspector's review: metallurgy reports, weld inspection reports, pressure test reports and final dimensional measurements as required in Section 6.2.

5 Performance Requirements

This section specifies a set of minimum measurement performance requirements that UMs must meet. If a meter is not flow-calibrated, the manufacturer shall provide sufficient test data confirming that each meter shall meet these performance requirements. The designer may also specify that a meter be flow-calibrated per Section 6.4. If a meter is flow-calibrated, then it shall meet the same minimum measurement performance requirements before the application of any calibration-factor adjustment. The amount of calibration-factor adjustment, therefore, should be within the error limits stated in the performance requirements. This is to ensure that a major flaw in the meter is not masked by a large calibration-factor adjustment. Calibration-factor adjustments are made to minimize a meter's measurement bias error. The designer is referred to Appendix A and Section 6.4.1 for an explanation of the methods and benefits of flow-calibrating a meter and for calibration-factor adjustment. The designer should also follow carefully the installation recommendations of Section 7, as any installation effects will add to the overall measurement uncertainty.

For each meter design and size, the manufacturer shall specify flow-rate limits for q_{min}, q_t and q_{max} as defined in Section 5.1. Each UM, whether flow-calibrated or not, shall perform within the more accurate measurement range for gas flow rates from q_t to q_{max} and within the less accurate range for gas flow rates less than q_t but greater than or equal to q_{min}, as defined in Sections 5.2, 5.2.1 and 5.2.2.

5.1 Definitions

Deviation The difference between the actual volume flow rate (e.g., flow rates in engineering units of acf/h) measured by the meter under test and the actual volume flow rate measured by a reference meter. Corrections shall be made for the differences in flowing gas pressure, temperature and compressibility between the two meters. The deviation is also measured as a difference between the mass flow rate through the meter under test and the mass flow rate through the reference meter. Typically, three or more test runs are averaged to establish the deviation at each nominal flow rate. These test runs can be used to determine the repeatability as defined below.

Error The observed deviation of a meter calculated as: Percent Error = [(Test Meter Reading – Reference Meter Reading) ÷ (Reference Meter Reading)] x 100.

Maximum Error The allowable error limit within the specified operational range of the meter, as shown in Figure 1 and Sections 5.2.1 and 5.2.2.

Maximum Peak-to-Peak Error The largest allowable difference between the upper-most error point and the lower-most error point as shown in Figure 1 and Section 5.2. This applies to all error values in the flow-rate range between q_t and q_{max}.

q_{max} The *maximum* gas flow rate through the UM that can be measured within the error limits, as shown in Sections 5.2.1 and 5.2.2 for large and small meters, respectively.

q_t The *transition* gas flow rate below which the expanded error limit is applicable, and where $q_t \leq 0.1 q_{max}$. See Figure 1 and Sections 5.2.1 and 5.2.2.

q_{min} The *minimum* gas flow rate through the UM that can be measured within the expanded error limits, as shown in Figure 1 and Sections 5.2.1 and 5.2.2.

q_i The actual measured gas flow rate passing through a UM under a specific set of test conditions.

Reference Meter	A meter or measurement device of proven flow measurement accuracy.
Repeatability	The closeness of agreement among a number of consecutive measurements of the output of the test meter for the same reference flow rate under the same operating conditions, approaching from the same direction, for full-scale traverses. The repeatability shall correspond to the 95% confidence interval of the deviation based on the assumption of a normal distribution. See Section 5.2.
Resolution	The smallest step by which the change of the flow velocity is indicated by the meter. See Section 5.2.
Velocity Sampling Interval	The time interval between two succeeding gas velocity measurements by the full set of transducers or acoustic paths. Typically, between 0.05 and 0.5 seconds, depending on meter size. See Section 5.2.
Zero-Flow Reading	The maximum allowable flow-velocity reading when the gas is at rest; i.e., both the axial and the non-axial velocity components are essentially zero. See Section 5.2.

5.2 General

The general flow-measurement performance of *all* UMs shall meet the following requirements, prior to making any calibration-factor adjustment.

Repeatability:	±0.2% for $q_t \le q_i \le q_{max}$
	±0.4% for $q_{min} \le q_i < q_t$
Resolution:	0.003 ft/s (0.001 m/s)
Velocity Sampling Interval:	$\leqq$ 1 second
Maximum Peak-to-Peak Error:	0.7% for $q_t \le q_i \le q_{max}$
(See Figure 1)	
Zero-Flow Reading:	<0.040 ft/s (12 mm/s) for each acoustic path

5.2.1 Large Meter Accuracy

UMs of 12″ (nominal) diameter size and larger shall meet the following flow-measurement accuracy requirements, prior to making any calibration-factor adjustment.

Maximum Error:	±0.7% for $q_t \le q_i \le q_{max}$
(See Figure 1)	±1.4% for $q_{min} \le q_i < q_t$

5.2.2 Small Meter Accuracy

UMs less than 12" (nominal) diameter shall meet the following flow-measurement accuracy requirements, prior to making any calibration-factor adjustment. Note that the requirements for the smaller meters have been relaxed slightly because of the difficulty in measuring acoustic transit times in turbulent gas flow when the path lengths are shorter.

Maximum Error:	±1.0% for $q_t \le q_i \le q_{max}$
(See Figure 1)	±1.4% for $q_{min} \le q_i < q_t$

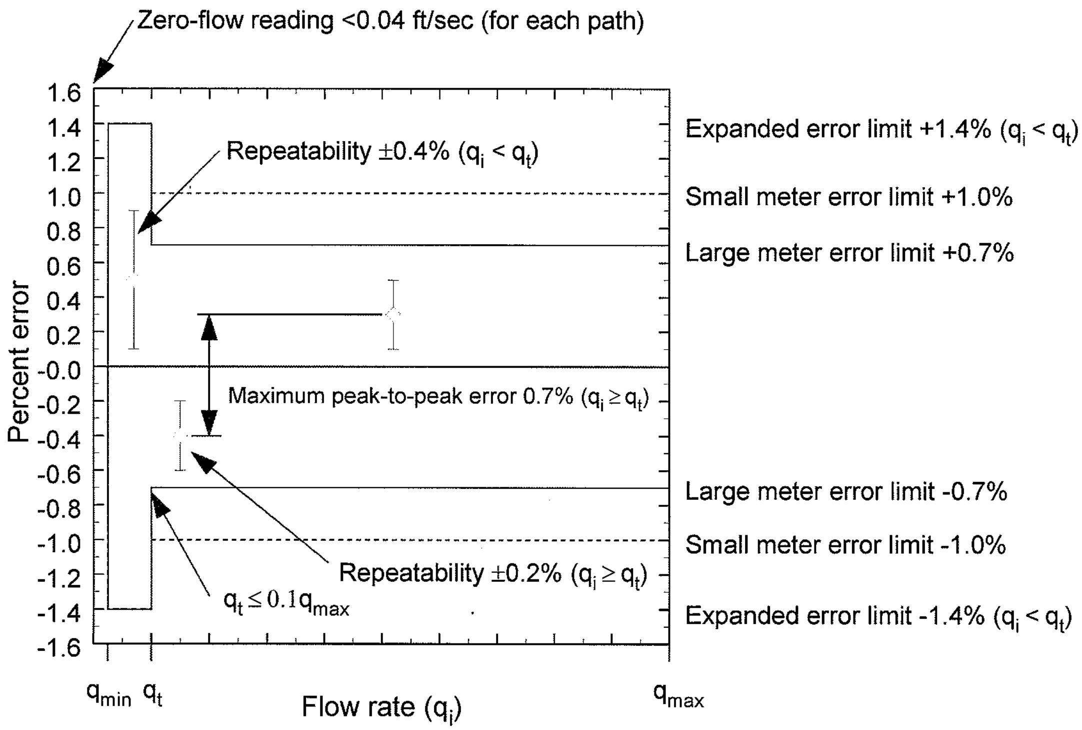

Figure 1

Performance Specification Summary

5.3 Pressure, Temperature and Gas Composition Influences

The UM shall meet the above flow-measurement accuracy requirements over the full operating pressure, temperature and gas composition ranges without the need for manual adjustment, unless otherwise stated by the manufacturer. If the UM requires a manual input to characterize the flowing gas conditions (e.g., gas density and viscosity), the manufacturer shall state the sensitivity of these parameters so that the operator can determine the need to change these parameters as operating conditions change.

6 Individual Meter Testing Requirements

Prior to the shipment of each UM to the designer or the operator, the manufacturer shall perform the following tests and checks on each meter. The results of all tests and checks performed on each meter shall be documented in a report (see Section 6.4.2) prepared by the manufacturer and submitted to the designer or the operator.

6.1 Leakage Tests

Every UM, complete with transducers and transducer isolation valves (if used), shall be leak-tested by the manufacturer after final assembly and prior to shipment to the designer or flow-calibration facility. The test medium should be an inert gas, such as nitrogen. The leak test pressure shall be a minimum of 200 psig, maintained for a minimum of 15 minutes, with no leaks detectable with a noncorrosive liquid solution or an ultrasonic leak detector as described in ASTM E 1002 - 93. This leak test does not preclude the requirements to perform a hydrostatic qualification test.

6.2 Dimensional Measurements

The manufacturer shall measure and document the average internal diameter of the meter, the length of each acoustic path between transducer faces and the axial (meter body axis) distance between transducer pairs.

The average internal diameter should be calculated from a total of 12 inside diameter measurements or the equivalent determined by a coordinate measuring machine. Four internal diameter measurements (one in the vertical plane, another in the horizontal plane and two in planes approximately 45° from the vertical plane) shall be made at three meter cross-sections: 1) near the set of upstream ultrasonic transducers, 2) near the set of downstream transducers and 3) half way between the two transducer sets.

If the acoustic path lengths or the axial distances between ultrasonic transducer pairs cannot be directly measured, then the unknown distances shall be calculated using right-angle trigonometry and distances that can be measured directly. Where the measurement of angles is difficult and the result is imprecise, such measurements shall not be used to calculate the required distances.

The meter body temperature shall be measured at the time these dimensional measurements are made. The measured lengths shall be corrected to an equivalent length at a meter body temperature of 68° F (20° C) by applying the applicable coefficient of thermal expansion for the meter body material. The individual corrected lengths shall then be averaged and reported to the nearest 0.0001" (0.01 mm).

All instruments used to perform these measurements shall have valid calibrations traceable to national standards; e.g., NIST in U.S.A.

These measurements and calculations shall be documented on a certificate, along with the name of the meter manufacturer, meter model, meter serial number, meter body temperature at the time dimensional measurements were made, date, name of the individual who made the measurements and name of the inspector if present.

6.3 Zero-Flow Verification Test (Zero Test)

To verify the transit-time measurement system of each meter, the manufacturer shall perform a Zero-Flow Verification Test. The manufacturer shall document and follow a detailed test procedure that includes the following elements, at a minimum.

- After blind flanges are attached to the ends of the meter body, the meter shall be purged of all air and pressurized with a pure test gas or gas mixture. The selection of the test gas shall be the responsibility of the manufacturer. However, the acoustic properties of the test gas must be well-known and documented.

- The gas pressure and temperature shall be allowed to stabilize at the outset of the test. The gas velocities for each acoustic path shall be recorded for at least 30 seconds. The mean gas velocity and standard deviation for each acoustic path shall then be calculated.
- Adjustments to the meter shall be made as necessary to bring the meter performance into compliance with the manufacturer's specifications and the specifications stated in this report.

If the measured speed-of-sound values are compared with theoretical values, the theoretically determined value shall be computed using a complete compositional analysis of the test gas, precise measurements of the test gas pressure and temperature and the equation of state used in AGA Report No. 8, "Detail Characterization Method."

As part of the test procedure, the manufacturer shall document the ultrasonic transducer serial numbers and their relative locations in the meter body. The manufacturer shall also document all parameters used by the meter; e.g., transducer/electronic transit-time delays, incremental timing corrections, and all acoustic path lengths, angles, diameters and other parameters used in the calculation of the gas velocity for each acoustic path. The manufacturer should note if the constants are dependent on specific transducer pairs.

The manufacturer may also implement a zero-flow offset factor, in engineering units of positive or negative feet per second or meters per second. This zero-flow offset factor would be applied to the meter's flow-rate output. Use of this factor is intended to improve the accuracy of the low gas velocity measurements, while not significantly affecting the accuracy of the higher velocity measurements. This zero-flow offset factor, if used, shall be documented by the manufacturer.

6.4 Flow-Calibration Test

If specified by the designer, the UM should be flow-calibrated. If a flow calibration is performed, the following nominal test flow rates are recommended, at a minimum: q_{min}, 0.10 q_{max}, 0.25 q_{max}, 0.40 q_{max}, 0.70 q_{max}, and q_{max}. The designer may also specify additional flow calibration tests at other flow rates. (See the example in Appendix A, where additional tests at 0.15 q_{max} and/or 0.20 q_{max} could be useful).

Flow-calibration tests should be performed at a gas pressure, temperature and density near the expected average operating conditions as specified by the designer. Tests at any other specific pressure, temperature and gas density range may be performed, if necessary. The designer may also require that specific piping configurations and/or flow conditioners be used during flow calibration, understanding that differences in upstream piping configurations may influence meter performance.

It is recognized that it may not be possible to test large UMs up to their maximum capacity because of the limitations of currently available test facilities. In such cases, the designer may specify a lower flow rate instead of q_{max}. The manufacturer should state on all applicable documents if a reduced q_{max} was used during flow-calibration tests.

The upstream flange and piping internal diameters should match and be aligned with the meter under test as specified in Section 7.2.3, "Protrusions".

All test measurements performed by a flow-calibration facility should be traceable with current calibration certificates to the applicable national standards; e.g., in the United States, traceable to NIST. Any property or thermophysical values (e.g., density, compressibility, speed of sound, critical flow factor, etc.) used during flow calibration shall be computed from AGA Report No. 8, "Detailed Characterization Method Equation of State".

The designer and the operator are encouraged to release test results to the gas industry, including flow-measurement accuracy data before and after calibration factors are applied. This will enable the manufacturers to demonstrate UM performance and will facilitate research evaluation of current UM technology. The Gas Research Institute currently has a program to compile UM calibration data.

6.4.1 Calibration Factors Adjustment

If a meter is flow-calibrated, the calibration factors should normally be applied to eliminate any indicated meter bias error. Some suggested methods of applying calibration factors are:

a) Using flow-weighted mean error (FWME) over the meter's expected flow range (the calculation of FWME is shown in Appendix A)

b) Using a more sophisticated error correction scheme (e.g., a multi-point or polynomial algorithm, a piecewise linear interpolation method, etc.) over the meter's range of flow rates.

For bi-directional flow calibrations, a second set of calibration factors may be used for reverse flow.

If an offset factor was established during the zero-flow validation tests, it may be revised based on the results of the flow calibration to optimize the meter's overall accuracy performance. The manufacturer shall document such a change in this factor and alert the operator that the zero-flow output may have some intentional bias in order to improve accuracy at q_{min}.

6.4.2 Test Reports

The results of each test required in Section 6, shall be documented in a written report supplied to the designer or the operator by the manufacturer. For each meter, the report shall include, at a minimum:

a. the name and address of the manufacturer
b. the name and address of the test facility
c. the model and serial number
d. the SPU firmware revision number
e. the date(s) of the test
f. the name and title of the person(s) who conducted the tests
g. a written description of the test procedures
h. the upstream and downstream piping configurations
i. a diagnostic report of the software configuration parameters
j. all test data, including flow rates, pressures, temperatures, gas composition and the measurement uncertainty of the test facility
k. a description of any variations or deviations from the required test conditions

At least one copy of the complete report shall be sent to the designer or the operator and one copy retained in the manufacturer's files. The manufacturer shall ensure that the complete report is available to the operator on request, for a period of 10 years after shipment of any meter.

6.5 Quality Assurance

The manufacturer shall establish and follow a written comprehensive quality-assurance program for the assembly and testing of the meter and its electronic system (e.g., ISO 9000, API Specification Q1, etc.). This quality-assurance program should be available to the inspector.

7 Installation Requirements

This section is directed to the designer to ensure that the UM will be installed in a suitable environment and in a piping configuration that allows the UM to meet the expected performance requirements.

7.1 Environmental Considerations

7.1.1 Temperature

The manufacturer shall provide ambient temperature specifications for the UM. Consideration should be given to providing shade, heating and/or cooling to reduce the ambient temperature extremes.

7.1.2 Vibration

UMs should not be installed where vibration levels or frequencies might excite the natural frequencies of SPU boards, components or ultrasonic transducers. The manufacturer shall provide specifications regarding the natural frequencies of the UM components.

7.1.3 Electrical Noise

The designer and the operator should not expose the UM or its connected wiring to any unnecessary electrical noise, including alternating current, solenoid transients or radio transmissions. The manufacturer shall provide instrument specifications regarding electrical noise influences.

7.2 Piping Configuration

7.2.1 Flow Direction

For bi-directional applications, both ends of the meter should be considered "upstream."

7.2.2 Piping Installations

Various combinations of upstream fittings, valves and lengths of straight pipe can produce velocity profile distortions at the meter inlet that may result in flow-rate measurement errors. The amount of meter error will depend on the type and severity of the flow distortion produced by the upstream piping configuration and the meter's ability to compensate for this distortion. Research work on installation effects is ongoing, so the designer should consult with the manufacturer to review the latest test results and evaluate how the accuracy of a specific UM design may be affected by the upstream piping configuration of the planned installation. In order to achieve the desired meter performance, it may be necessary for the designer to alter the original piping configuration or include a flow conditioner as part of the meter run.

To ensure that the UM, when installed in the operator's piping system, will perform within the specified flow-rate measurement accuracy limits as shown in Sections 5.2, 5.2.1 and 5.2.2, the manufacturer shall do one of the following as desired by the designer/operator:

1. 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 $\pm 0.3\%$ due to the installation configuration. This error limit should apply for any gas flow rate between q_{min} and q_{max}. The recommendation should be supported by test data.

2. Specify the maximum allowable flow disturbance (e.g., the limits on swirl angle, velocity profile asymmetry, turbulence intensity, etc.) at the meter's upstream flange or at some specified axial distance upstream of the meter that will not create an additional flow-rate measurement error of more than $\pm 0.3\%$ due to the installation configuration. This error limit should apply for any gas flow rate between q_{min} and q_{max}. The recommendation should be supported by test data.

Instead of following the manufacturer's recommendation in 1 or 2 above, the designer may choose to flow-calibrate the UM *in situ*, or in a flow-calibration facility where the test piping configuration can be made identical to the planned installation.

Research has indicated that asymmetric velocity profiles may persist for 50 pipe diameters or more downstream from the point of initiation. Swirling velocity profiles may persist for 200 pipe diameters or more. A flow conditioner properly installed upstream of a UM may help shorten the length of straight pipe required to eliminate the effects of an upstream flow disturbance. A UM may be able to compensate for some level of flow-profile disturbance. Research is still being conducted to quantify the sensitivity of different UM designs to various flow-profile disturbances.

7.2.3 Protrusions

Changes in internal diameters and protrusions should be avoided at the UM inlet because they create local disturbances to the velocity profiles. The UM bore, flanges and adjacent upstream pipe should all have the same inside diameter, to within 1%, and be aligned carefully to minimize flow disturbances, especially at the upstream flange. The upstream flange's internal weld should be ground smooth.

No part of the upstream gasket or flange face edge should protrude into the flow stream by more than 1% of the internal diameter. During installation, three or more insulating flange bolt sleeves can be used at the 4, 8 and 12 o'clock positions to keep the gasket centered while tightening the nuts.

Thermowells, located as specified in Section 7.2.5, are excluded from the above protrusion limits.

7.2.4 Internal Surface

The internal surface of the UM should be kept clean of any deposits due to condensates or traces of oil mixed with mill-scale, dirt or sand, which may affect the meter's cross-sectional area. The UM's operation depends on a known cross-sectional area to convert mean gas velocity to a flow rate. If a layer of deposits accumulates inside the UM, the cross-sectional area will be reduced, causing a corresponding increase in gas velocity and a positive measurement error.

Examples: Given a 6.000" internal diameter UM, a deposit layer of only 0.008" around the inside surface will cause a +0.53% flow-measurement error. For a 20.000" meter, the same 0.008" coating would cause a +0.16% error. (For comparison, 0.008" equals the thickness of two pieces of 20-pound copy machine paper.)

7.2.5 Thermowells

For uni-directional flow, the designer should have the thermowell installed downstream of the meter. The distance from the downstream flange face to the thermowell should be between 2D and 5D. For bi-directional flow installations, the thermowell should be located at least 3D from either UM flange face. "D" is defined as the nominal diameter of the meter.

Research on the effects of thermowell placement is ongoing and the designer should consult with the manufacturer for recommendations based on the most current test data. The thermowell orientation with respect to acoustic paths should also be recommended by the manufacturer.

The designer is cautioned that high gas velocities may cause flow-induced thermowell vibration. Catastrophic metal fatigue failure of the thermowell could eventually result from the vibration.

7.2.6 Accoustic Noise Interference

Some pressure-reducing control valves, designed to reduce audible noise, may produce very high levels of ultrasonic noise under certain flowing conditions. The ultrasonic noise from these "quiet" control valves can interfere with the operation of a nearby ultrasonic meter. Research work on ultrasonic noise interference is ongoing, so the manufacturer should be consulted when planning to install a UM near a pressure-reducing control valve.

7.2.7 Flow Conditioners

Flow conditioners may or may not be necessary, depending on the manufacturer's meter design and the severity of any upstream flow-profile disturbance. The designer should consult with the manufacturer to determine the benefits, if any, of installing various types of flow conditioners, given the upstream piping configuration.

7.2.8 Orientation of Meter

The designer should consult with the manufacturer to determine if there is a preferred meter orientation for a given upstream piping configuration that is known to produce flow-profile distortions.

7.2.9 Filtration

Filtration of the flowing gas is probably not necessary for most applications of a UM. However, the accumulation of deposits due to a mixture of dirt, mill scale, condensates and/or lubricating oils should be avoided. See Section 7.2.4. Filtration may be necessary if any of the above conditions is known to exist.

7.3 Associated Flow Computer

The UM's output is typically an uncorrected volume (actual volume at line conditions), either per unit of time or accumulated. Therefore, an associated flow computer or corrector must be installed by the designer to correct the volume rate and accumulated volume for pressure, temperature and compressibility (to obtain standard cubic feet, for example), and to provide the necessary data retention and audit trail. Optionally, the flow-computer functions could be integrated into the UM's SPU by the manufacturer.

For bi-directional applications, the UM should be treated as two separate meters, associated with two "meter runs" in a single flow computer or with two separate flow computers.

For other applicable flow-computer requirements, the designer should refer to API MPMS Chapter 21.1, *Flow Measurement Using Electronic Metering Systems*. A UM would be considered a "linear meter" in that document.

7.3.1 Flow-Computer Calculations

The necessary calculations are similar to the equations described in AGA Report No. 7, *Measurement of Gas by Turbine Meters*, and are summarized in the following expressions:

$$Q_b = Q_f\,(P_f/P_b)\,(T_b/T_f)\,(Z_b/Z_f)$$

$$V_b = \int Q_b\,dt$$

Where:

Q_b = flow rate at base conditions

Q_f = flow rate at flowing conditions

P_b = base pressure, typically 14.73 psia (101.325 kPa)

P_f = absolute static pressure of gas at flowing conditions

T_b = base temperature, typically 519.67° R (288.15° K)

T_f = absolute temperature of gas at flowing conditions

Z_b = compressibility factor of gas at base conditions, per AGA Report No. 8

Z_f = compressibility factor of gas at flowing conditions, per AGA Report No. 8

V_b = accumulated volume at base conditions

$\int$ = integrated over time

dt = integration increments of time, typically 1 second.

The first equation converts the flow rate at line conditions of pressure, temperature and compressibility to a flow rate at base conditions. The second equation represents the accumulation process in which flow rates at base conditions are accumulated to volumes over time. For more details, refer to AGA Report No. 7.

7.4 Maintenance

The operator should follow the manufacturer's recommendations for maintenance. Periodic maintenance could be as simple as monitoring several SPU diagnostic measurements, such as signal quality and speed of sound for each acoustic path. For example, it may be possible to detect an accumulation of deposits on the transducer faces by measuring a reduction in the received ultrasonic pulse strength.

When possible, the operator should verify that the UM measures near zero when no gas is flowing through the meter. When performing this test, the operator should bypass or defeat any low flow cut-off function and be aware that any meter-run temperature differences will cause thermal convection currents of gas to circulate inside the meter, which the UM may measure as a very low flow rate.

8 Field Verification Tests

The manufacturer shall provide a written field verification test procedure to the operator that will allow the UM to be functionally tested to ensure that the meter is operating properly. These procedures may include a combination of a zero-flow verification test, speed-of-sound measurement analysis, individual path measurement analysis, internal inspection, dimensional verification and other mechanical or electrical tests.

The manufacturer should provide an uncertainty analysis to demonstrate that these field performance verification tests are sufficient to validate the meter's specified physical and electrical performance characteristics. The manufacturer should make reference to the uncertainty method used in this analysis.

Some performance aspects of the UM's condition should be evaluated by comparing the speed of sound reported from the meter with the speed of sound derived from the AGA Report No. 8, "Detail Characterization Method Equation of State." A chromatographic analysis from a sample of gas taken at the time of speed-of-sound measurement is required for valid comparison. An extended analysis (beyond C_6) may not be necessary for typical natural gas mixtures.

The decision to perform periodic transfer proving or flow calibration is left to the parties using the meter.

9 Reference List

- AGA Engineering Technical Note M-96-2-3, *Ultrasonic Flow Measurement for Natural Gas Applications,* American Gas Association, 1515 Wilson Boulevard, Arlington, VA 22209

- AGA Transmission Measurement Committee Report No. 7, *Measurement of Gas by Turbine Meters*, American Gas Association, 1515 Wilson Boulevard, Arlington, VA 22209

- AGA Transmission Measurement Committee Report No. 8, *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases*, American Gas Association, 1515 Wilson Boulevard, Arlington, VA 22209

- NFPA 70, *National Electrical Code,* 1996 Edition, National Fire Protection Association, Batterymarch Park, Quincy, MA 02269

- API Manual of Petroleum Measurement Standards Chapter 21, September 1993, *Flow Measurement Using Electronic Metering Systems,* American Petroleum Institute, 1220 L Street NW, Washington, DC 20005

- ASTM Designation: E 1002 – 96, *Standard Test Method for Leaks Using Ultrasonics*, American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, U.S.A.

- Code of Federal Regulations, Title 49—Transportation, Part 192, (49 CFR 192), *Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards*, U.S. Government Printing Office, Washington, DC 20402

- GERG Technical Monograph 8 (1995), *Present Status and Future Research on Multi-path Ultrasonic Gas Flow Meters,* Christian Michelsen Research AS, the GERG Project Group and Programme Committee No. 2 - Transmission and Storage, Groupe Européen De Recherches Gazières

- ISO 9951: 1993, *Measurement of gas flow in closed conduits — Turbine meters*, International Organization for Standardization, Case Postale 56, CH-1211 Genève 20, Switzerland

- ISO/TR 12765: 1997(E), *Measurement of fluid flow in closed conduits — Methods using transit time ultrasonic flowmeters*, International Organization for Standardization, Case Postale 56, CH-1211 Genève 20, Switzerland

- OIML R 6 *General provisions for gas volume meters,* 1989 (E), International Recommendation, Organization Internationale de Métrologie Légale, Bureau International de Métrologie Légale, 11, rue Turgot - 75009 Paris - France

- OIML D 11 *General requirements for electronic measuring instruments,* 1994 (E), International Document, Organization Internationale de Métrologie Légale, Bureau International de Métrologie Légale, 11, rue Turgot - 75009 Paris – France

APPENDIX A

Multipath Ultrasonic Meter Flow-Calibration Issues

A.1 Why Flow-Calibrate a Multipath Ultrasonic Meter?

The flow-measurement accuracy specifications in Section 5 permit a multipath ultrasonic meter to have a maximum error of up to ±0.7% and a maximum peak-to-peak error of 0.7% for gas flow rates between q_t and q_{max}, for meters (nominally) 12″ in diameter or greater. Similarly, for meters (nominally) less than 12″ in diameter, the maximum error can be as much as ±1.0% and the maximum peak-to-peak error can be 0.7%. As the following example illustrates, multipath ultrasonic meters may operate within these allowable measurement accuracy envelopes, but still produce significant and costly errors in terms of the measured gas volume. One effective means of minimizing the measurement uncertainty of a multipath ultrasonic meter is to flow-calibrate the meter.

Example:

A multipath ultrasonic meter manufacturer rates the flow capacity of an 8″ diameter UM as follows. Note that the specified value for $\mathbf{q_t}$ is less than 0.1$\mathbf{q_{max}}$, per the requirements of Section 5.1.

$$\mathbf{q_{max}} = 87{,}500 \text{ acf/h}$$

$$\mathbf{q_t} = 7{,}500 \text{ acf/h}$$

$$\mathbf{q_{min}} = 3{,}750 \text{ acf/h}$$

Flow calibration of this meter at a test laboratory yields the following results, after averaging multiple test runs near each of the recommended nominal test rates (RNTR).

RNTR	Nominal Test Rate (acf/h)	Actual Test Rate - Reference Meter (acf/h)	Meter Reported Rate* (acf/h)	UM Error* (%)
$\mathbf{q_{min}}$	3,750	3,475	3,508	+0.953
0.10 $\mathbf{q_{max}}$	8,750	6,890	6,916	+0.376
0.25 $\mathbf{q_{max}}$	21,875	21,980	21,910	-0.318
0.40 $\mathbf{q_{max}}$	35,000	37,801	37,682	-0.315
0.70 $\mathbf{q_{max}}$	61,250	60,415	60,190	-0.372
$\mathbf{q_{max}}$	87,500	86,500	86,183	-0.366

* The "Meter Reported Rate" has been rounded to the nearest whole acf/h. The "UM Error" is based on the values for the "Meter Reported Rate" prior to rounding and the "Actual Test Rate - Reference Meter."

Table A.1 Flow-Calibration Data for an 8″ Diameter UM

The flow-calibration data from Table A.1 are plotted as open circles on Figure A.1 below.

To estimate the error in the volume of gas measured by this meter, assume that, in field service, the gas is typical pipeline-grade quality and that it flows through the UM at a rate of 60,415 acf/h (i.e., roughly 0.7 q_{max}) at a line pressure of 600 psig. For this operating condition, the flow-calibration data indicate that the meter will underestimate the flow rate by 0.372% (see Table A.1). If this flow rate is held constant for a year, the resulting measurement error is nearly 90 million standard cubic feet of gas per year. Also, note that the error, in terms of the measured volume of gas, is proportional to the square of the UM diameter, so a comparable percentage error for a 20″ diameter meter would be more than 500 million standard cubic feet of gas per year.

Also note, from the example above, that the magnitude and direction (i.e., overestimation or underestimation) of the measurement error of the UM is a function of the flow rate. That is, in this case, the UM *over* predicts the flow rate on the low end of the operational range and *under* predicts on the high end of the range. Furthermore, the meter error can be substantially corrected by using the flow-calibration data. The following discussion explains how test-flow data can be used to correct or minimize meter error.

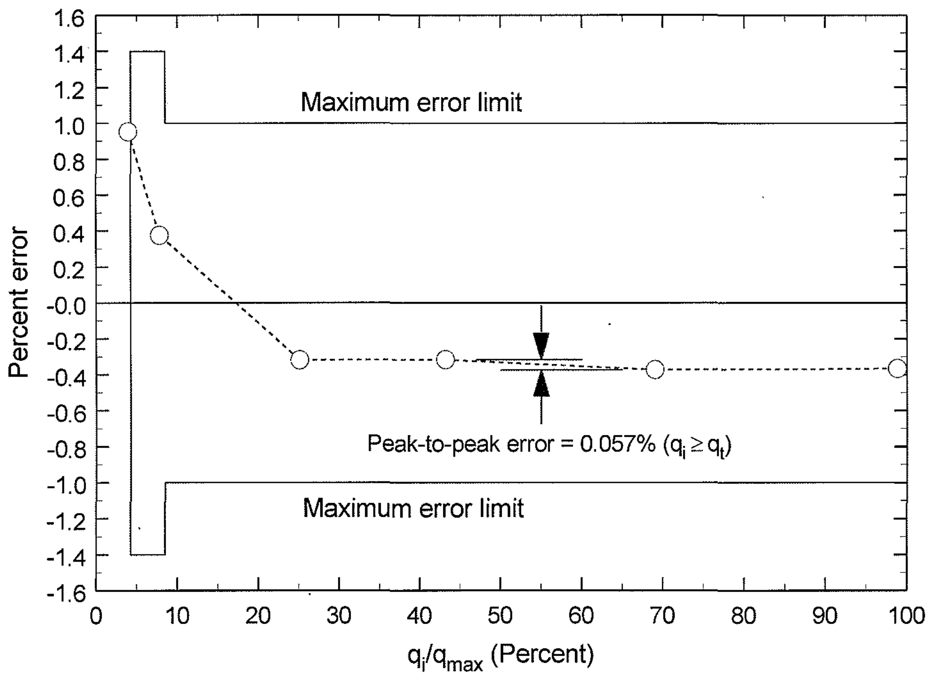

Figure A.1 Uncorrected Flow-Calibration Data for an 8″ Diameter UM

Note that the individual data points in Figure A.1 represent averaged values for multiple test runs near each of the recommended nominal test rates.

A.2 Methods for Correcting a UM's Flow-Measurement Error

The above example demonstrates the potential value of minimizing a UM's measurement inaccuracy or uncertainty. The total flow-measurement error of a UM consists of two parts: (1) *random* (or precision) errors and (2) *systematic* (or bias) errors. Random errors can be caused by various influences on a meter's operation. Random errors normally follow a certain statistical distribution. The magnitude of the random error can usually be reduced by acquiring multiple measurement samples and then applying accepted statistical principles. Systematic errors normally cause repeated UM measurement readings to be in error (for some unknown reason) by roughly the same amount. In most cases, flow calibration of a UM can help eliminate or, at least, minimize the measurement error of the meter. Operational experience has shown that, in most cases, the major portion of the total flow-measurement error of an uncalibrated UM is due to systematic errors.

Due to machining tolerances, variations in component manufacturing processes, variations in the meter assembly process and other factors, each UM has its own unique operating characteristics. Thus, to minimize a particular UM's flow-measurement uncertainty, the manufacturer can flow-calibrate a UM and then use the calibration data to correct or compensate for the UM's measurement error. More than one error correction technique is available to the manufacturer, depending on the meter application and the needs of the operator.

Following is a description of an error correction technique that utilizes a single calibration-factor correction — the flow-weighted mean error (FWME) factor. If a UM's flow-measurement output is linear over the operational flow range of the meter, the FWME correction method is effective at minimizing the measurement uncertainty of the meter. Other single calibration-factor correction techniques are also available. If a UM's flow-measurement output is nonlinear over the meter's operational range, more sophisticated error correction techniques can be applied. For instance, a higher-order curve fit algorithm, such as a second- or third-order polynomial equation can be used to characterize the meter's output, based on the available test data. An exhaustive discussion of the various meter error correction techniques is beyond the scope of this discussion. The designer or operator should consult with the manufacturer regarding the available options for a particular UM.

A.3 Example of a Flow-Weighted Mean Error (FWME) Calculation

The calculation of a meter's FWME from actual flow-test data is a method of calibrating a meter when only a single calibration-factor correction is applied to the meter's output. Application of this factor to a UM's output is similar to the use of an index gear ratio in a turbine or rotary flow meter. As noted above, use of the FWME factor is only one of several alternative methods of adjustment to a UM's calibration to minimize the flow-measurement uncertainty of the meter (see Section 6.4.1).

The example used in Section A.1 above will now be used to demonstrate how to calculate the FWME for an 8″ diameter UM that has been flow-calibrated under operating conditions similar to those that the meter would experience during field service. A single calibration-factor (i.e., one FWME correction factor), F, is determined and then applied to the test results such that the resulting FWME is equal to zero. The meter's performance, both before and after the calibration factor is applied, should be compared with the requirements specified in Section 5.0.

The FWME for the data set presented in Table A.1 of Section A.1 above is calculated as follows.

$$FWME = SUM\ [\ (q_i / q_{max}) \times E_i\ ]\ /\ SUM\ (q_i / q_{max})$$

Where: SUM is the summation of the individual terms representing each of the test-flow points,
q_i / q_{max} is a weighting factor (wf_i) for each test flow point, and
E_i is the indicated flow-rate error (in percent) at the tested flow rate, q_i.

(An alternative method for computing the FWME that decreases the contribution of the highest flow-rate point is to use a reduced weighting factor, such as 0.4, when $q_i \geq 0.95\ q_{max}$. The designer or the operator may also use different weighting factors, depending on whether the meter is run mostly in the lower, middle or upper range of flow.)

Applying the above equation for FWME to the test data in Table A.1 (where q_{max} = 87,500 acf/h) produces the results shown in Table A.2. Note that a column labeled wf_i is included in Table A.2 to show the weighting factor that is applied to each E_i value.

Actual Test Rate - Reference Meter (acf/h)	$wf_i = q_i / q_{max}$	E_i (%)	$wf_i \times E_i$ (%)
3,475	0.0397	+0.953	+0.0378
6,890	0.0787	+0.376	+0.0296
21,980	0.2512	-0.318	-0.0799
37,801	0.4320	-0.315	-0.1361
60,415	0.6905	-0.372	-0.2569
86,500	0.9886	-0.366	-0.3618
SUM =	2.4807	SUM =	-0.7672 %

Table A.2 FWME Calculation Summary for an 8" Diameter UM

The FWME value for the test data in Table A.2 is calculated as follows (without any calibration-factor correction being applied to the data).

$$FWME = SUM\ (wf_i \times E_i)\ /\ SUM\ (wf_i) = -0.7672 / 2.4807 = -0.3093\%$$

A single calibration factor, F, can now be applied to the meter output to reduce the magnitude of the measurement error. The value of F is calculated using the following equation.

$$F = 100 / (100 + FWME)$$

For this example, the FWME is -0.3093% and the single calibration factor , F, is calculated to be 1.0031. By multiplying the UM's output by 1.0031 (i.e., by applying the calibration factor), the calculated FWME should then equal zero. The adjusted test data are presented in Table A.3 below. In this table, each E_i has been adjusted to obtain a calibration-factor-adjusted value, E_{icf}, using the following equation.

$$E_{icf} = (\ E_i + 100\ ) \times F - 100$$

E_i (%)	wf_i	E_{icf} (%)	$wf_i \times E_{icf}$ (%)
+0.953	0.0397	+1.2662	+0.0503
+0.376	0.0787	+0.6874	+0.0541
-0.318	0.2512	-0.0088	-0.0022
-0.315	0.4320	-0.0058	-0.0025
-0.372	0.6905	-0.0629	-0.0434
-0.366	0.9886	-0.0569	-0.0563
SUM =	2.4807	SUM =	0.0000 %

Table A.3 "FWME-Corrected" Flow-Calibration Data Summary for an 8″ Diameter UM

Using the adjusted data from Table A.3 to calculate FWME produces the following result.

FWME = 0.0000 / 2.4807 = 0.0000 %

In the following plot, the FWME-corrected flow-calibration data have been added to the test data presented in Figure A.1. The triangles represent the meter's error after a single calibration factor of 1.0031 has been applied to the original flow-calibration data.

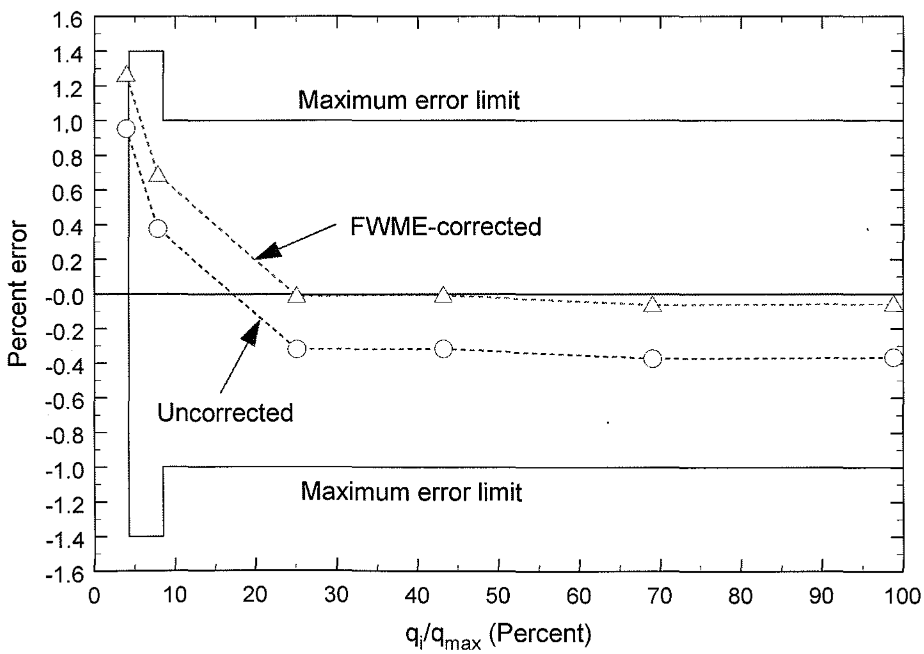

Figure A.2 Uncorrected and FWME-Corrected Flow-Calibration Data for an 8″ Diameter UM

Figure A.2 shows that for gas flow rates above about 25% of the capacity of the meter, the measurement error has been virtually eliminated by applying a single FWME calibration-factor adjustment to all of the test flow data. However, for flow rates below about 25% of the meter's capacity, the single FWME calibration-factor adjustment does not completely eliminate the measurement error because the UM has a nonlinear characteristic over this portion of its operating range. Therefore, the operator must either accept the higher measurement error on the low end of the meter's operational range or apply a more sophisticated correction scheme to reduce or eliminate the measurement error on the low end of the meter's range.

Note: The laboratory test data used in this example calculation of FWME were provided courtesy of Southwest Research Institute, San Antonio, Texas.

APPENDIX B

Electronics Design Testing

The design of the UM's electronics should be tested to demonstrate that the UM will continue to meet the performance requirements of Section 5, while operating under the influences and disturbances specified in the current revisions of OIML R 6, *General Provisions of Gas Volume Meters*, and OIML D 11, *General Requirements for Electronic Measuring Instruments*. OIML is the Organisation Internationale de Metrolocie Legale (i.e., the International Organization of Legal Metrology). OIML publishes these documents for the expressed purpose of harmonizing national performance requirements and testing procedures for gas meters.

For the climatic conditions, the requirements shall be for class 4K3, "open locations with average climatic conditions, thus excluding polar and desert environments." For the mechanical conditions, the requirements shall be for class 3/4M5, "locations with significant or high levels of vibration and shock"; e.g., transmitted from adjacent compressors. The combination of these two conditions leads to OIML class F for determining the severity level for each test.

These test requirements shall apply to the design of all circuit boards, ultrasonic transducers, interconnecting wiring and customer wiring terminals. The electronics shall be in operation, measuring zero flow, and remain 100% functional during the tests. In the case of high-voltage transient and electrostatic discharge tests, the meter may temporarily stop functioning but shall automatically recover within 30 seconds.

During these tests, the ultrasonic transducers may be operated in a smaller and lighter test cell (or test cells) instead of a full meter body. However, the transducers shall actually be measuring zero flow and be exposed to the same test conditions as other parts of the electronic system.

The following sections provide a brief description of the required tests and severity levels. Note that the severity levels are listed here for information only and may change in future revisions of the OIML documents. For detailed testing procedures, the manufacturer may refer to the referenced OIML documents, which, in turn, refer to applicable International Electrotechnical Commission (IEC) publications.

B.1 Static Temperature, Dry Heat

Exposure to a static temperature of 131° F (55° C) during a period of two hours. The change of temperature shall not exceed 1.8° F/min (1° C/min) during heating up and cooling down. The humidity of the air shall be such that condensation is avoided at all times.

B.2 Static Temperature, Cold

Exposure to a static temperature of -13° F (-25° C) during a period of two hours. The change of temperature shall not exceed 1.8° F/min (1° C/min) during heating up and cooling down. The humidity of the air shall be such that condensation is avoided at all times.

B.3 Damp Heat, Steady State

Exposure to a constant temperature of 86° F (30° C) and a constant relative humidity of 93% for a period of four days. The handling of the electronics shall be such that no condensation of water occurs on this unit.

B.4 Damp Heat, Cyclic

Exposure to cyclic temperature variations between 77° F and 131° F (25° C and 55° C), maintaining the relative humidity above 95% during the temperature change and low temperature phases, and at 93% at the upper temperature phases. Condensation should occur on the electronics during the temperature rise. The test consists of two cycles of 24 hours each following the specified procedure per cycle.

B.5 Random Vibration

Exposure to a random vibration level specified below.

Frequency range:	10-150 Hz
Total RMS level:	5.25 ft/s^2 (1.6 m/s^2)
ASD level 10-20 Hz:	(0.048 m/s^2)
ASD level 20-150 Hz:	-3 dB/octave
Number of axes:	3
Duration:	2 minutes or longer if necessary to check the various functions.

B.6 Sinusoidal Vibration

Exposure to a sinusoidal vibration by sweeping the frequency in a range of 10-150 Hz at 1 octave per minute at an acceleration level of 6.56 ft/s^2 (2 m/s^2). The electronics shall be tested in three perpendicular axes. The duration of the test is 20 cycles per axis.

B.7 Mechanical Shock

The electronic unit, standing in its normal position of use on a rigid surface, is tilted at one bottom edge to a height of 1″ (25 mm) and then is allowed to fall freely onto the test surface — twice for each bottom edge.

B.8 Power Voltage Variation

Exposure to the specified power supply conditions for a period long enough to achieve temperature stability and to perform checks on the performance of the meter.

Mains voltage:	Nominal mains voltage ± 10%
Mains frequency:	(50 Hz or 60 Hz) ± 2%

B.9 Short Time Power Reduction

Exposure to mains voltage interruptions and reductions specified below. The reductions shall be repeated 10 times with an interval of at least 10 seconds.

Reduction:	100% during 10 ms (milliseconds) 50% during 20 ms

B.10 Bursts (Transients)

Exposure to bursts of voltage spikes having a double exponential wave form. Each spike shall have a rise time of 5 ns (nanoseconds) and a half amplitude duration of 50 ns. The burst length shall be 15 ms; the burst period (repetition time interval) shall be 300 ms. The peak value shall be 0.5 kV.

B.11 Electrostatic Discharge

Exposure to 10 electrostatic discharges with a time interval between each discharge of 10 seconds. If the electrode giving the discharge is in contact with the electronics, the test voltage shall be 6 kV. If the electrode is approaching the electronics and the discharge occurs by spark, the test voltage shall be 8 kV.

B.12 Electromagnetic Susceptibility

Exposure to a radiated electromagnetic field. The frequency range shall be 0.1 to 500 MHz, with a field strength of 10 Volts/meter (V/m).

APPENDIX C

Ultrasonic Flow Measurement for Natural Gas Applications

A.G.A. Operating Section Transmission Measurement Committee
Engineering Technical Note M-96-2-3

This technical note contains reference information for measuring high-pressure natural gas using large-capacity ultrasonic flow meters, including principles of operation, technical issues, evaluation of measurement performance, error analysis, calibration and reference literature.

Prepared by the
Ultrasonic Metering Task Group

ACKNOWLEDGMENTS

This technical note represents a great deal of work by the members of the Ultrasonic Task Group of the A.G.A. Transmission Measurement Committee. Large parts of the document were provided by Jan Drenthen, Ron McCarthy and Huib Dane of Instromet Ultrasonic Technologies. Kevin Warner of Daniel Flow Products provided another significant portion, along with John Stuart of Pacific Gas and Electric, Mike Rogi of NOVA Gas Transmission Ltd. and Jim Witte of Tenneco. Valuable technical input and timely editing were provided by Terry Grimley of Southwest Research Institute.

The assistance and support of other industry associations are also appreciated: in particular, Ray Teyssandier and Steve Stark representing the American Petroleum Institute Committee on Gas Measurement, and Pieter van der Kam representing the Groupe Européen de Recherches de Gasières (GERG) and its Ultraflow project.

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The task group would also like to thank its first two chairmen, Gene Tiemstra and Bob Pogue, both formerly of NOVA Gas Transmission Ltd., who laid the groundwork for the Technical Note.

Phil Barg, Chair
Ultrasonic Task Group
March 1996

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1 Introduction

The Transmission Measurement Committee of the American Gas Association submits the following reference information for measuring natural gas with ultrasonic flow meters.

Ultrasonic meters measure flow by measuring velocity in the gas stream using pulses of high-frequency sound. By measuring the transit time, the average velocity of the gas is calculated. Volume and mass flow rates are then calculated using standard equations of state (such as A.G.A. Report No. 8, *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases*).

These meters have a number of important attributes for measuring large volumes of natural gas. For instance, ultrasonic meters have a high turndown ratio and incur a small pressure loss. The uncertainty of these meters is in line with other types of meters. However, care must be taken by the user in order to ensure a proper understanding of the characteristics and limitations of these meters, so that the expected results can be achieved.

Single-path and multipath meters are addressed. Where there is no reference to the number of paths, the particular section can be assumed to apply to both. Multipath meters are used to reduce uncertainties, especially when dealing with non-uniform gas velocity profiles and other disturbances such as swirl.

This is a compilation of information by experts in the field at the time of publication. It is not intended for use as a reference in contracts.

1.1 Task Group Scope

a) Develop an A.G.A. Engineering Technical Note to address the following:

- Review the current state of ultrasonic metering technology.
- Share and disseminate operating experience with ultrasonic meters. Leverage off of the experience of the European Community.
- Develop an understanding of the potential applications and related business parameters.

b) Identify technical issues or limitations and related research needs.

c) Review current industry standards with a view to developing an A.G.A. report for the installation and operation of ultrasonic meters.

1.2 Engineering Technical Note Scope

This Technical Note is limited to ultrasonic meters in high-pressure natural gas transmission. Although references are made to ultrasonic meters for liquid flow applications, the general theme and the recommendations relate specifically to high-pressure natural gas applications.

2 Principle of Operation

2.1 Introduction

An ultrasonic flow meter is a measurement device that consists of ultrasonic transducers, which are typically located along a pipe's wall. The transducers are in direct contact with the gas stream and, therefore, the pressure at the location of the transducer is contained by gas-tight seals. Ultrasonic acoustic pulses transmitted by one transducer are received by the other one, and vice versa. Figure 1 shows a simple geometry of two transducers, *Tx1* and *Tx2*, at an angle φ with respect to the axis of a straight cylindrical pipe with diameter *D*. In some instruments a reflection path is employed, where the acoustic pulses reflect one or more times off the pipe wall.

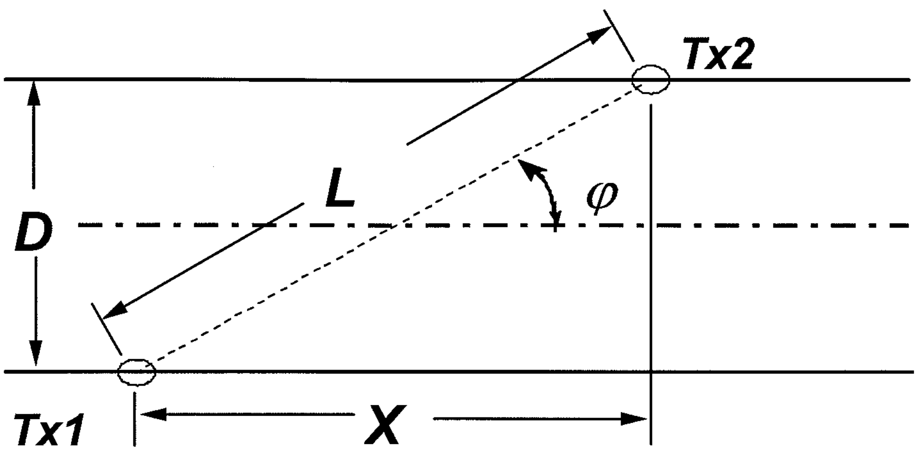

Figure 1 - Simple geometry of ultrasonic flow measurement

The acoustic pulses are crossing the pipe, like a ferryman crossing a river. Without flow, they propagate with the same speed in both directions. If the gas in the pipe has a flow velocity other than zero, pulses traveling downstream with the flow will move faster, while those traveling upstream against the flow will move slower. Thus, the downward travel times t_D will be shorter and the upward ones t_U will be longer, as opposed to when the gas is not moving. The travel times are measured electronically. From the transit times, the measured velocity $\bar{v}$ is calculated by

$$\bar{v} = \frac{L^2}{2X} \frac{(t_U - t_D)}{t_U t_D} \qquad \textbf{(1)}$$

where *L* denotes the straight line length of the acoustic path between the two transducers, and *X* denotes the axial distance exposed to the flow. The speed of sound can be calculated from

$$c = \frac{L}{2} \frac{(t_U + t_D)}{t_U t_D} \qquad \textbf{(2)}$$

2.2 Theory of Ultrasonic Flow Measurement

2.2.1 Pipe Flow Velocity

Flow velocity may be described by a three-dimensional velocity vector *v*, which in general depends on space *x* and time *t*: $v = v(x,t)$. In steady, swirl-free flow through long straight cylindrical tubes with radius R, the only non-zero time-averaged velocity component will be in the axial direction, and it will be a function of radial position r only. The function for a fully developed velocity profile can be approximated by a semi-empirical power law

$$v(r) = v_{\max}\left(1 - \frac{r}{R}\right)^{\frac{1}{n}} \tag{3}$$

where n is a function of the pipe Reynolds number Re and pipe roughness. For smooth pipes, Prandtl's equation applies (Schlichting, 1968)

$$n = 2\log_{10}\left(\frac{Re}{n}\right) - 0.8 \tag{4}$$

In smooth pipes, if the Reynolds number is known, n can be calculated. Using this value of n, the velocity profile $v(r)$ can be computed, which essentially is a steady-state description of the flow. Figure 2 shows the velocity profiles, normalized by the maximal velocity v_{max} at the center of the pipe, as computed by the formulas mentioned above, for three Reynolds number values of $Re=10^5$ (n=7.455), $Re=10^6$ (n=9.266) and $Re=10^7$ (n=11.109).

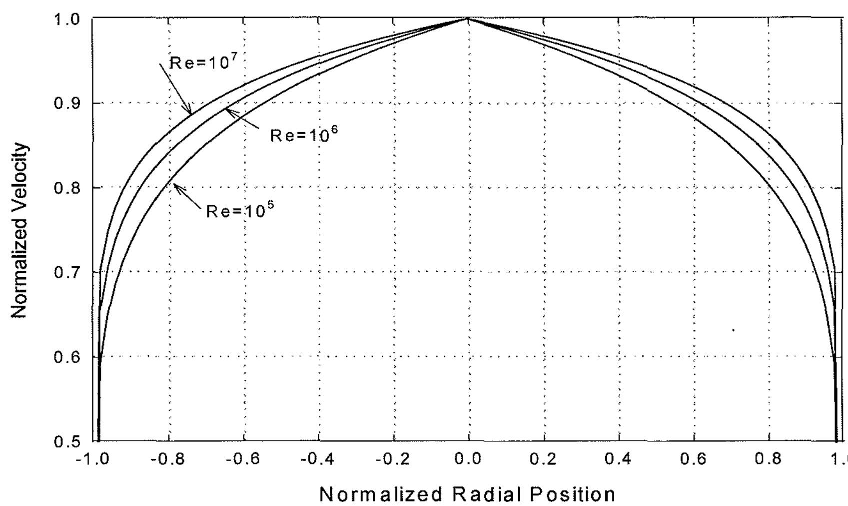

Figure 2 - Smooth pipe turbulent velocity profiles for $Re = 10^5$, 10^6 and 10^7

In fully developed turbulent flow, the instantaneous velocity is a more complicated function of space and time. According to Hinze (1975), v = v(x,t) can be decomposed as

$$v(x,t) = u(x,t) + w(x,t) \tag{5}$$

where u denotes the local mean value (which generally will be a function of time), and w refers to the zero-mean turbulent velocity fluctuations. These turbulent velocity fluctuations, which always occur in a stationary turbulent flow, can be considered as a random process.

2.2.2 Ultrasonic Flow Measurement

In ultrasonic flow measurement, acoustic pulses are transmitted and received by a pair of piezoelectric transducers. The propagation of acoustic waves through a moving fluid has been described theoretically (Lighthill, 1972). It is characterized by a specific velocity, which in general is a function of the pressure, density and composition of the fluid. This velocity c may be calculated using the theory of thermodynamics as

$$c^2 = \frac{\partial P}{\partial \rho} \tag{6}$$

where P denotes the pressure, ρ the density of the fluid, and ∂ the partial derivative. The thermodynamic speed of sound, however, is a value for an unbounded fluid at zero frequency (Goodwin, 1994). In a pipe, due to thermal and viscosity effects, the actual speed of sound at an ultrasonic frequency may differ slightly from the thermodynamic value. For the purpose of gas flow metering, however, the difference may be neglected. Moreover, neglecting the frequency dependence of the speed of sound means that the difference between the phase-velocity and the group-velocity is considered negligible.

The acoustic path along which the ultrasonic pulses are propagated may be computed using the ray-tracing method of geometrical acoustics. If the flow velocity has only a component in the longitudinal (x-) direction, which depends on radial position: $v = v(r)$, then Snell's law (Morse and Ingard, 1986) takes the form

$$\frac{c(r)}{\cos \varphi(r)} + v(r) = constant \tag{7}$$

along the path where $\varphi(r)$ denotes the local path angle. To simplify even further, assume the velocity of sound c to be a constant. Then, according to Boone and Vermaas (1991), the ray-tracing equations can be written

$$\frac{dx}{dt} = c \cos \varphi(r) + v(r)$$

$$\frac{dr}{dt} = c \sin \varphi(r)$$

$$\frac{d\varphi}{dt} = - \cos^2 \varphi(r) \frac{dv(r)}{dr} \tag{8}$$

If the transducer positions are given, these equations can be solved to find the acoustic path. Because the velocity is not constant over the cross-section of the pipe, the path will not be a straight line but a curved one. The path angle with respect to the pipe axis will not be constant, and the upstream path will differ from the downstream one. The curvature of the path depends on both *Re* and Mach number (*Ma*), and it increases with increasing Mach number and with the curvature of the velocity profile. As an example, Figure 3 shows the path with an exaggerated curvature.Equations (1) and (2) are derived from

$$t_U = \frac{L}{\sqrt{c^2 - \bar{v}^2 \sin^2\varphi} - \bar{v}\cos\varphi} \tag{9}$$

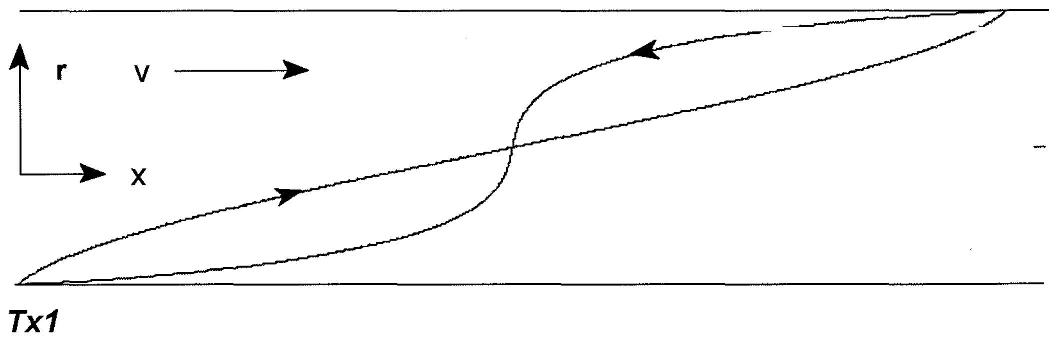

Figure 3 - Exaggerated curvature of acoustic path

and

$$t_D = \frac{L}{\sqrt{c^2 - \bar{v}^2 \sin^2\varphi} + \bar{v}\cos\varphi} \tag{10}$$

where the overbar denotes the line-integral along the path:

$$\bar{v} = \frac{1}{L} \int_L v(r)\, dr. \tag{11}$$

In other words, the velocity perceived by the instrument equals the average, along the acoustic path, of the fluid velocity component in the direction of the path. If the transducers are withdrawn beyond the edge of the flow stream, appropriate corrections should be made to equations (9) and (10). Because velocity of sound effects can occur in the transducer pockets if temperature gradients exist, the general requirement is that the velocity of sound along the entire acoustic path should be representative of the velocity of sound where the fluid is in motion.

Normally a user is interested in the bulk mean velocity V of the medium, which means the velocity averaged over the cross-section A of the pipe

$$V = \frac{1}{A} \iint_A v(r)\, dA \qquad \textbf{(12)}$$

If v only has a component normal to the cross-section, this bulk mean velocity is computed from

$$V = k_c \cdot \bar{v} \qquad \textbf{(13)}$$

where k_c denotes the correction factor defined by

$$k_c = \frac{\frac{1}{A} \iint_A v(r)\, dA}{\frac{1}{L} \int_L v(r)\, dL} \qquad \textbf{(14)}$$

which can be computed once $v(r)$, L and A are known. Because $v(r)$ is a function of Re, the correction factor is also a function of Re. If the path is in a plane through the pipe axis, one approximation (of many) is given by

$$k_c \approx \frac{1}{1.12 - 0.011 \log_{10} Re} \qquad \textbf{(15)}$$

for a fully developed turbulent flow. If the path is located outside a plane through the pipe axis (i.e., along a tilted chord), the k-factor and its dependency on Re will be different.

In many practical situations the Reynolds number may not be known exactly. However, the range of the Reynolds number may be known so that a fixed value of the k-factor can be chosen in such a way as to minimize the deviation from the true value over the given range of the Reynolds number. For instance, when the lateral position p of the chord equals $R/2$, the average value of k_c for the Reynolds number in the range 10^4 to 10^8 is 0.996. For this particular lateral path position, the variation of k_c is less than 0.4% over the specified Reynolds number range. This method may also be applied in multipath configurations, which may reduce the errors associated with the flow-profile deviation from the assumed axial-symmetric power law.

In a multipath meter, the transducers can be arranged in many different ways. The acoustical paths may be parallel to each other, but other orientations are possible as well. The meter may employ either direct or reflected transmission along two or more tilted chords. The method used to combine the measurements from the individual paths into an average velocity also varies with the specific meter design. It is important to note that not all methods require the use of the previously described *k*-factor for the average flow calculation.

In a multipath meter, $\bar{v}\ (p)$ 16is calculated for a set of discrete values of *p*. Since *V* can be written as

$$V = \frac{2}{A} \int_{-R}^{R} \bar{v}\,(p) \sqrt{(\,R^2 - p^2\,)}\, dp \qquad \textbf{(16)}$$

where17 $\bar{v}\ (p)$ is the average flow velocity along the path having a lateral position, *p*, the integral can be approximated by applying a suitable numerical integration technique; for instance, Gauss integration. In this way, an estimate of *V* can be computed based on $\bar{v}\ (p)$ 18 for each path

$$V = \sum_{i=1}^{N} w_i\ \bar{v}(p_i\,) \qquad \textbf{(17)}$$

where w_i are weighting factors depending on the applied integration technique and p_i are the lateral positions of the ultrasonic transducers. This is a widely used technique for numerical integration. This method has been implemented in various ways in multipath ultrasonic flow-meters. Depending on the method used, the path locations can be chosen such that the weighting factors are constants that do not require an assumption of velocity profile.

Multiplication of the average velocity by the flow area, *A*, yields the volumetric flow rate *Q*:

$$Q = V A \qquad \textbf{(18)}$$

2.2.3 Generation of Ultrasonic Signals

The ultrasonic signals required for the flow measurement are generated and received by transducers. Piezoelectric transducers employ crystals or ceramics, which are set into vibration when an alternating voltage is applied to the piezoelectric element. The vibrating element generates sound waves in the fluid. Since the piezoelectric effect is reversible, the element will become electrically polarized and produce voltages related to the mechanical strain when the crystal is distorted by the action of incident sound waves. Because the acoustic impedance of the gas is much smaller than that of the piezoelectric element, a layer of material is typically used between the gas and the piezoelectric element to maximize the acoustic efficiency. This layer of material has an acoustic impedance between those for the gas and for the piezoelectric element.

Usually the surface of the transducer has a plane circular shape. The acoustic behavior of a plane circular piston has been well documented (Stepanishen, 1971, and Harris, 1981). When continuously transmitting a single frequency, the sound pressure field takes the form of an acoustic beam, the width of which depends on the ratio of acoustic wavelength to piston diameter: the larger this ratio, the wider the beam. Because the acoustic beam spreads, the sound pressure level gradually decreases along the beam. Furthermore, the sound is attenuated through absorption in the gas. Although in some gases absorption may be considerable (for instance, carbon dioxide), in natural gas applications it is usually negligible over the length of the acoustic path.

The transducers may be excited simultaneously or alternately with one or more transmissions in each direction. The acoustic frequency and pulse repetition rate may vary between different designs.

2.2.4 Signal Processing

In signal processing, two groups of methods can be distinguished: time-domain methods and frequency-domain methods. Whether a particular method from one group or the other is applied depends on the time-of-flight versus the period of the ultrasonic pulse, or the path length versus the acoustic wavelength. In most ultrasonic flow meters for natural gas applications, the path length (from 0.1 to 1 m) is considerably longer than the acoustic wavelength (usually about 3 mm) and, therefore, time-domain methods are employed.

Among the time-domain methods, the most widely known ones are the single-pulse transit-time measurement method and the correlation peak-shift method. In the first, two essential operations are carried out: first the received pulse is detected, and then its time of arrival is estimated.

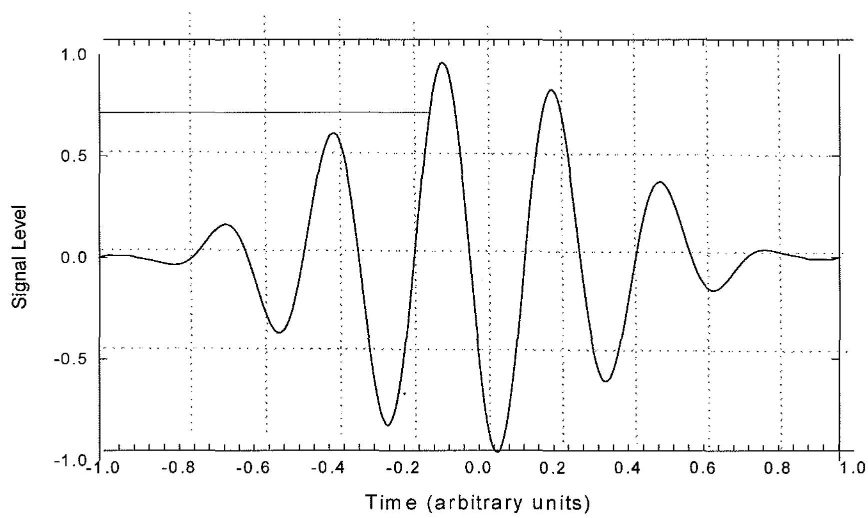

Figure 4 - Simple detection of received pulse

The method that is applied by virtually all detection techniques is to identify one or several predetermined zero-crossings in the received pulse. A simple way, which is widely used, is to trigger on a predetermined amplitude level in the received pulse and then detect the first subsequent zero-crossing, as shown in Figure 4. This technique may be refined by using a longer pulse and detecting several zero-crossings in the stable part of the pulse. In this way the transient part of the pulse where the pulse period varies is avoided. Further, for every pulse the transit time is computed as an average of the individual transit times corresponding to each zero-crossing. A more advanced method is to make use of the relatively fixed amplitude pattern in the transient part of the pulse. A somewhat different approach is to use a correlation technique; i.e., to correlate the emitted and received pulses and calculate the transit time as the time corresponding to the peak of the correlation function.

When the acoustic signal gets corrupted, the signal detection becomes increasingly difficult. Two kinds of errors may occur: missed pulses and erroneous zero locations. The latter leads to timing errors. Inconsistencies in the recognition of the correct timing point may be due to changes in received amplitude, changed wave form or noise. Through proper design of the detector, the occurrence of errors can be minimized. In practice, the consequence of an erroneous zero location may be more important than that of a missed pulse. Corrupted signals, however, may be rejected based on validity tests as discussed in Section 4.

The transit times normally are checked for spurious values, which can then be discarded from the data set. A number of alternative methods of checking are possible. The values should always be checked to ensure that the velocity of the fluid and the velocity of sound that they suggest are physically possible. Finally, based on a set of n upstream and n downstream measured transit times, the mean upstream and downstream transit times can be calculated.

3 Technical Issues

3.1 Speed of Sound in Natural Gas

Ultrasonic flow meters send "pings" of sound both upstream and downstream through the flowing natural gas stream. The upstream and downstream flight times for the pings are subtracted from each other to obtain the difference in flight time. Because of this subtraction, the effects of the speed of sound are canceled out. It is apparent from equation (1) that the velocity measured by an ultrasonic flow meter does not require knowledge of the speed of sound to measure the gas stream velocity. Equation (2) shows that the ultrasonic meter can measure the speed of sound by dividing the path distance by the flight time. This measured value of the speed of sound can be compared with a theoretically calculated value to evaluate the proper operation of the ultrasonic meter.

Therefore, it is valuable for the user of an ultrasonic meter to be familiar with how sound speed can be affected by changes in gas properties. The speed of sound in natural gas is dependent on pressure, temperature, relative density and the composition mixture, as shown in the following graphs (see pages C-14 through C-16).

The three natural gas mixtures plotted are GRI's reference natural gas mixtures from Report No. GRI-93/0181. These are the same as those referenced in A.G.A. Report No. 8 and have the characteristics and compositions as shown in the following page.

GRI'S REFERENCE NATURAL GAS MIXTURES

CHARACTERISTICS AND COMPOSITIONS

	GRI Gulf Coast Reference Gas Mixture	GRI Amarillo Reference Gas Mixture	GRI Ekofisk Reference Gas Mixture	Air
Speed of Sound: ft/sec (m/s)	1412.4 (430.5)	1377.8 (420.0)	1365.6 (416.2)	1118.05 (340.78)
@ 14.73, 60F				
G_r	0.581078	0.608657	0.649521	1.00
HV, Btu/cf	1036.05	1034.85	1108.11	
Mole Percent:				
Methane	96.5222	90.6724	85.9063	
Nitrogen	0.2595	3.1284	1.0068	78.03
Carbon Dioxide	0.5956	0.4676	1.4954	0.03
Ethane	1.8186	4.5279	8.4919	
Propane	0.4596	0.8280	2.3015	
i-Butane	0.0977	0.1037	0.3486	
n-Butane	0.1007	0.1563	0.3506	
i-Pentane	0.0473	0.0321	0.0509	
n-Pentane	0.0324	0.0443	0.0480	
n-Hexane	0.0664	0.0393	0.0000	

Speed-of-sound calculations were provided through GRI's Basic Research Program on Fluid Properties

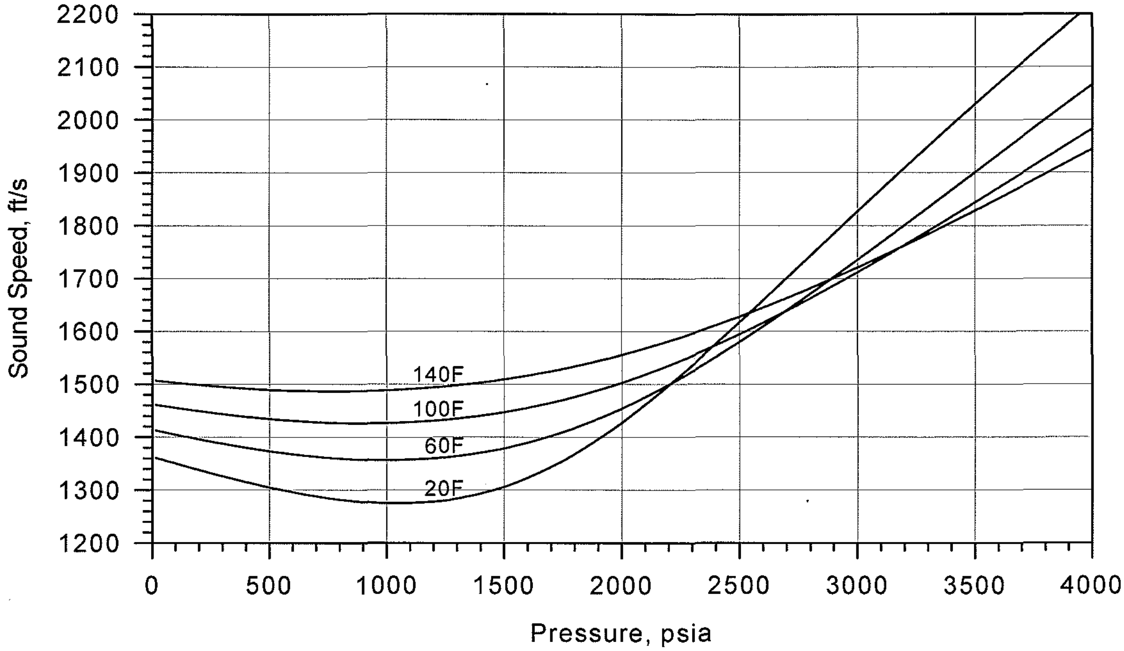

Figure 5 - Speed of Sound in 0.58 G_r "Gulf Coast" Gas, US units.

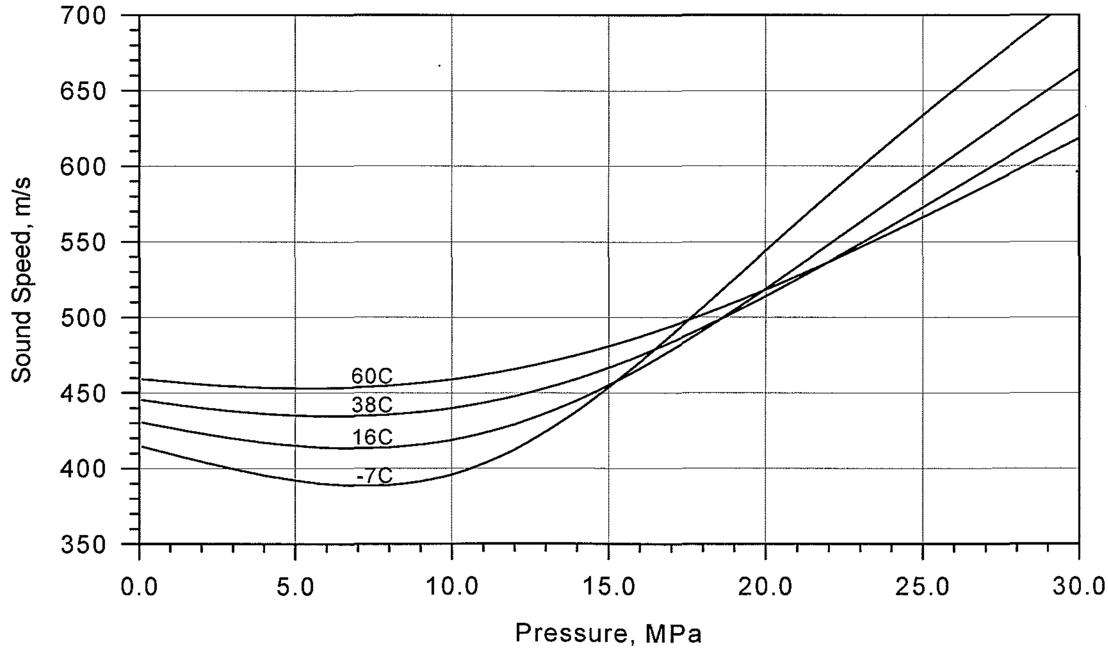

Figure 6 - Speed of Sound in 0.58 G_r "Gulf Coast" Gas, SI units.

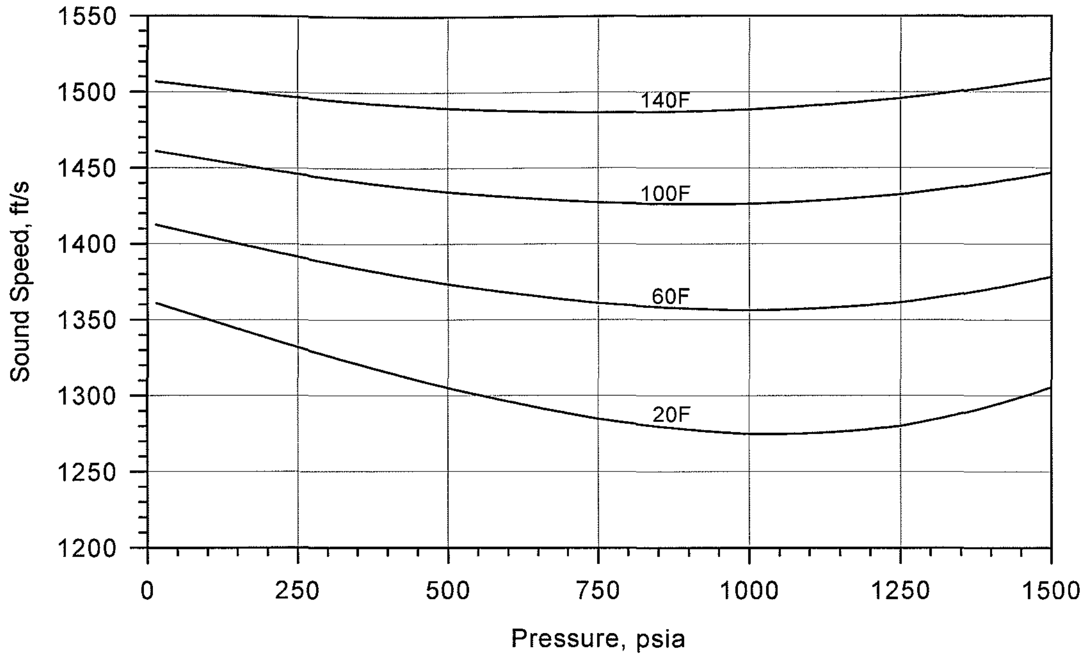

Figure 7 - Speed of Sound in 0.58 G_r "Gulf Coast" Gas below 1500 psia, US units.

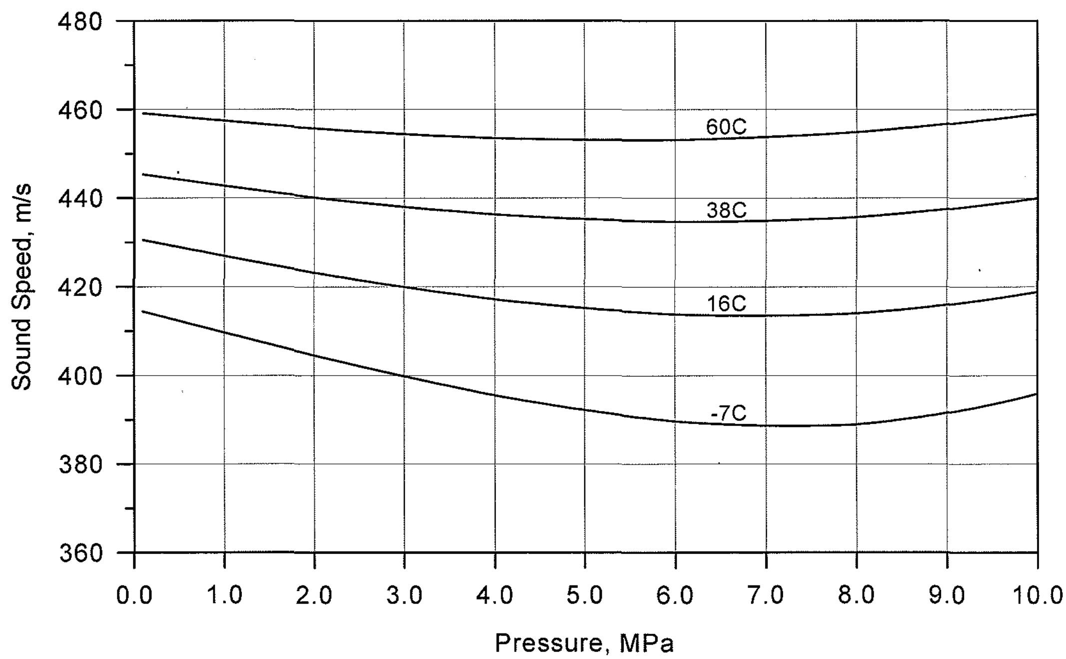

Figure 8 - Speed of Sound in 0.58 G_r "Gulf Coast" Gas below 1500 psia, SI units.

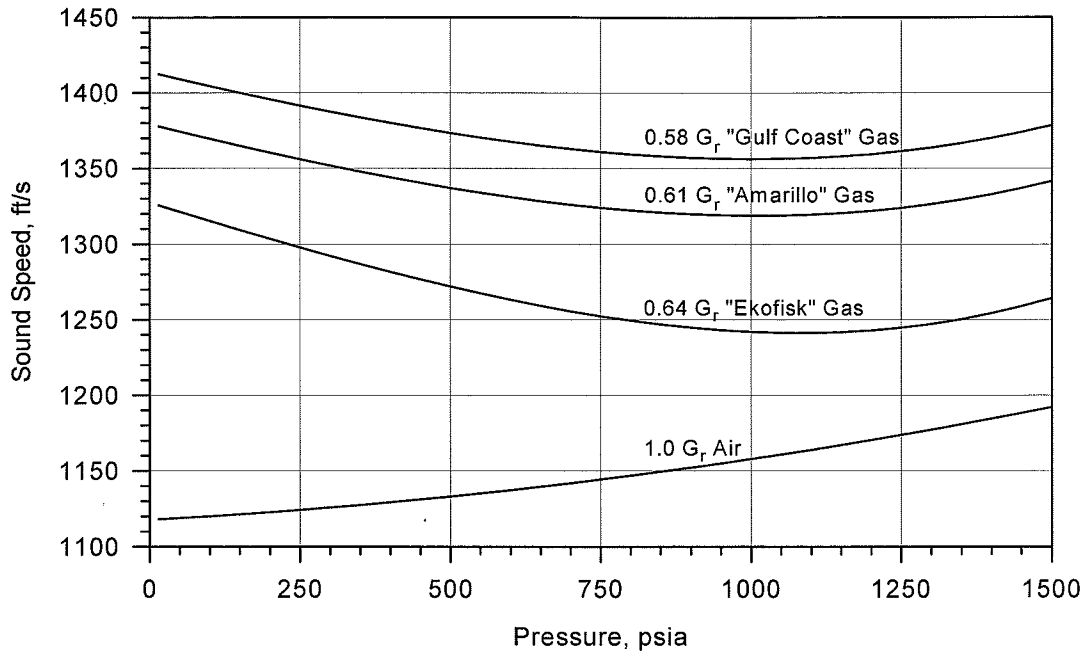

Figure 9 - Speed of Sound in Various Gases at 60 F, US units.

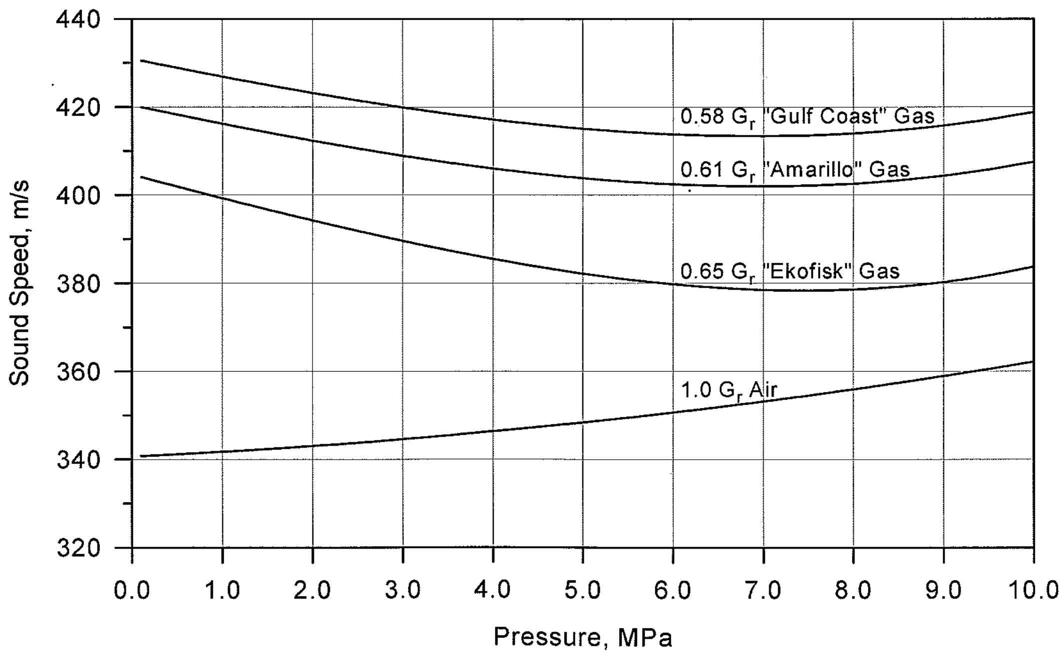

Figure 10 - Speed of Sound in Various Gases at 16 C, SI units.

3.2 Installation Requirements

Meters available from different manufacturers have differing recommended practices for installation. Given the different designs and proprietary features available, this is not unreasonable. Manufacturers may recommend an installation based on A.G.A. Report No. 7, *Measurement of Gas by Turbine Meters*, or there may be more or less stringent requirements, depending on testing the manufacturers have done. Single-path meters will require considerably more stringent requirements and are still unlikely to match the performance of multipath meters.

An important consideration for the user is that the body of testing and research is still quite small relative to the testing of other meter types, such as orifice meters. Manufacturers may specify certain requirements, based on their testing, but the particular installation may not produce the same results.

3.2.1 Installation Configurations

Since the ultrasonic meter is a fluid-velocity measuring device, optimum performance will be achieved when the piping configuration immediately upstream of the meter provides a well-developed flow profile entering the meter. Since a multipath ultrasonic meter measures the fluid velocity at several locations, it effectively tends to average the velocity profile of most normal flow conditions, thus minimizing the influence of minor flow distortions on meter performance.

To minimize possible flow-distortion effects, manufacturers may recommend a flow conditioner in the piping upstream of the meter. Flow swirl conditions may be caused by pipe fittings, valves or regulators preceding the meter inlet piping. Regardless of location, some flow conditioners will not eliminate the effect of strong jetting.

The installations recommended by manufacturers vary, but generally require a length of 5 to 10 nominal pipe diameters upstream of the meter and 3 nominal pipe diameters downstream of the meter. It should be emphasized that the 5 to 10 diameters upstream length is based on a very limited amount of data and should be considered as a *minimum* requirement, which is only valid when reasonable upstream conditions exist (e.g., low levels of swirl, small asymmetries in flow profile).

The inside diameter of both inlet and outlet piping should be the same size as the meter. Further testing is required to establish the effect of small changes in diameter.

There should be no pipe connections within the upstream or downstream piping other than pressure taps, temperature wells, densitometer connections or flow conditioners if they are used. The manufacturers' recommendations for the upstream length for single-path meters are generally longer.

The ultrasonic meter's design makes it inherently bi-directional. In bi-directional installations, upstream piping is required on both ends of the meter.

If a flow conditioner is used, the type and installation recommendations should be obtained from the manufacturer.

3.2.2 Pressure and Temperature Measurements

A pressure tap can be located on the body of the meter, or in close proximity (within 5D). Temperature measurements should be located 1D to 5D downstream to minimize the effects of the thermowell. If there is two-way flow or downstream location is impractical, the effect of thermowell penetration on the velocity profile should be minimized. Typically, a thermowell less than one-third of the pipe diameter, located between 3D and 5D of the meter, is recommended.

3.2.3 Density Measurement

Although it is desirable to sample the gas as close as possible to the ultrasonic measuring section conditions when using densitometers, care must be exercised not to disturb the meter inlet flow or to create an unmetered bypass. When used, densitometers should be installed downstream of the ultrasonic meter. References should be made to manuals on the various densitometers for further information.

3.2.4 Contamination, Strainers and Filters

Contamination of the transducers, including debris that sticks to the surface (such as grease or oil build-up), may attenuate the signal or alter the velocity calculation resulting in poor performance. If contamination is a problem with a particular gas stream, provision to remove and clean the transducers should be made.

Due to the nonintrusive design of the ultrasonic meter, small amounts of debris and foreign particles, such as those found in normal pipeline-quality systems, may pass through the meter without damaging the device. Measurement accuracy may be affected slightly, depending on the type, size and amount of debris passing through the meter. Even large debris should not cause damage. Measurement accuracy will be affected by debris that remains in the meter and restricts the bore or blocks a path.

If strainers or filters are used, they should be sized so that at maximum flow there is a minimum pressure drop and flow distortion. It is recommended that the differential pressure across a strainer or filter be monitored to ensure the strainer or filter is in good condition so as to prevent flow distortion.

3.2.5 Over-Range Protection

The ultrasonic meter will not be damaged by extreme gas velocities. Extreme gas velocities can occur when pressurizing, blowing down or purging the meter run. Extreme gas velocities can also occur as a result of the operation of the downstream piping system. The accuracy of the meter may be affected once the flow exceeds the stated maximum velocities. Therefore, it is advisable to ensure that the meter installation flow rates are clearly stated at the design stage and that the size of the meter allows for expected over-range conditions.

Rapid pressurization and depressurization of ultrasonic meters should be avoided since this can cause damage to the transducers.

3.2.6 Bypass

Bypassing for maintenance is not required for installations in which the meter is fitted with isolation valves that provide the capability of removing the transducers without interrupting the flow or flow measurement. In installations without this capability, installations requiring proving or installations requiring the removal of the entire meter for cleaning or inspecting, bypass piping is recommended if flow interruption is not allowed.

3.2.7 Pressure-Reducing Valves and Noise

Interference with the meter's signals has been a problem at some sites that have other equipment that generates ultrasonic noise (such as control valves). One particular problem is that noise attenuating trim used on some control valves produces sound in the range that the meter is using. In these applications, it may be necessary to change the trim (although this is not always an option) or to physically separate the meter and the valve by a sufficient distance. Because of the potential for profile distortion and/or the generation of ultrasonic noise, the installation of a throttling device, such as a regulator or a partially closed valve, in close proximity to the meter (especially upstream) is not recommended.

Generally, noise in other frequencies is not as much of a problem, although high noise level or resonant frequencies could interfere with the meter.

3.2.8 Vibration

Piping vibration should be kept to a minimum, since the electronic apparatus mounted on the pipe will be susceptible to damage if the levels are high enough. Specific levels should be specified by the manufacturer.

3.2.9 Orientation

Generally, the meter will be designed to be installed in a horizontal run of pipe, although other orientations should work just as well. A primary consideration is whether the transducers are mounted in recesses in the body and whether these will be susceptible to collecting dirt and liquids in the gas stream. The orientation of the transducers in the meter body differs among manufacturers.

3.2.10 Pigging

Some meter designs will allow pigs to pass without interference, while others may require retraction of the transducers. Where the transducers are recessed, provision to clean the transducer pocket should be made on lines that may be pigged.

3.2.11 Pulsation

Preliminary testing has shown that pulsation has little effect on ultrasonic meter performance. In theory, the impact is small, since any errors should average out.

3.2.12 Gas Composition

Within the gas phase, composition should not have a large effect on performance. A high percentage of liquids (beyond an entrained mist) will likely affect accuracy somewhat. Some information on the composition of the gas should be available from the speed of sound; however, this may be useful only as an indication that the composition is changing. A high percentage of carbon dioxide (CO_2) in the gas may cause problems, as CO_2 tends to attenuate the signal.

3.2.13 Stress and Strain Issues

The meter should be designed to meet applicable mechanical codes and standards. Information on the change in meter factor resulting from high-pressure operation is either available from the manufacturer or gained as the result of a calibration.

3.3 Meter Construction

3.3.1 General

The ultrasonic meter consists of two basic components:

1. the body
2. the electronics

3.3.2 Body

The body and all other parts forming the pressure-containing structures should be designed and constructed of material suitable for the service conditions for which the meter is rated.

The body end connections should be designed in accordance with the appropriate flange and threaded connection standards.

The body should be identified to show the following.

1. manufacturer's name
2. maximum and minimum capacities in actual volume units — actual cubic feet per hour
3. maximum allowable operating pressure, psig
4. serial number
5. date of manufacture.
6. body material
7. an arrow indicating the direction of positive flow
8. minimum operating pressure

3.3.3 Electronics

The electronics include the circuits and devices required to emit and receive ultrasonic pulses, measure the travel times of the ultrasonic pulses (transit time), calculate the actual flow rate and transmit this information to a flow computer.

The flow information can be transferred to a flow computer via a serial communications port, through a frequency signal or by other analog methods. Since the ultrasonic meter is bi-directional, the electronics provide flow information in positive or negative units to identify flow direction. An arrow on the meter body identifies the direction of positive flow. If analog output is provided, then analog status and direction indicators should also be available.

3.4 Performance Characteristics

3.4.1 Swirl Effect

The ultrasonic meter is designed for a condition that approaches axial flow at the meter inlet. If the fluid at the meter inlet has significant swirl (mainly tangential components), the individual path velocities at a given flow rate will be different from that for axial flow. For accurate measurement, such a swirl effect must be reduced to an insignificant level through proper installation practices, as described previously. The level at which the swirl becomes insignificant to the metering accuracy depends on the specific meter design.

Circulation and cross-flow can be measured along suitable mid-radius and diameter paths in the spool piece. Circulation and cross-flow can also be measured utilizing other path arrangements, such as those contained in a thick flange or in a short spool piece that specifically includes paths for sensing such secondary flows. Their unwanted contribution to the measured axial flow can be minimized or eliminated by use of weighting factors determined theoretically or empirically.

3.4.2 Meter Error, Uncertainty and Accuracy

Manufacturers specify upper and lower bounds for the flow error, within which the ultrasonic meter should operate. The upper and lower bounds may be a function of the flow rate and will typically allow more error near the lower end of the meter's operating range. There can also be a small zero offset caused by very small discrepancies in the measurement of the upstream and downstream transit times at zero flow. This zero offset looks like a constant error in average velocity and will have a more pronounced effect at low flow rates, when expressed as a percentage of flow. The manufacturer's data sheet should be consulted for the magnitude of the zero offset.

For increased accuracy, meters can be flow-calibrated. An optimum meter factor and zero offset are then calculated so that the meter error at any given flow rate, within the operating range of the meter, will fall within the manufacturer's specified error band for a flow-calibrated meter, which is typically ± 0.5%.

A complete statement of measurement error needs to include the measurement uncertainty of the prover system.

3.4.3 Meter Performance Curve

The meter error at a given flow rate can be determined from a meter performance curve, which is produced by testing each meter against a prover system at several different flow rates, then plotting the percentage error in flow reading versus the prover flow rate. The error curve can be plotted against actual flow rate, average velocity or Reynolds number, depending on the intended purpose of the curves.

When plotted against actual flow rate or average velocity, the meter performance curves at various pressures and temperatures are generally a family of distinctive curves.

When the meter error is plotted against the Reynolds number, the meter performance curve tends to show flow-profile effects. This method of plotting would normally be used only for specific experiments and is not recommended for general use. It is important to consider that the presence of a small zero offset can obscure apparent profile effects, since the effect of the zero offset on the percentage error will vary as a function of the Reynolds number.

3.4.4 Pressure Loss

The pressure loss of an ultrasonic meter is negligible due to the design, which shows no significant protrusions, obstructions or constrictions to the fluid flow.

3.4.5 Maximum Flow Rate

Ultrasonic meters are generally designed for a maximum velocity, v_{max}, which is used to calculate the maximum actual flow rate, Q_{max}. The maximum flow rate of the meter is generally limited by the ability to receive undistorted ultrasonic pulses, which can be a function of both transducer design and the signal processing methods. The maximum flow rate typically remains the same for all pressures and temperatures within the stated maximum meter operating range.

The maximum flow rate Q_{max} is a simple function of the maximum velocity given as

$$Q_{\max} = A \; v_{\max} \tag{19}$$

The maximum flow rate can also be expressed in terms of a "standard" flow rate by making the appropriate pressure, temperature and compressibility corrections.

3.4.6 Minimum Flow Rate and Rangeability

The minimum flow rate (or minimum capacity rating) for an ultrasonic meter is the lowest flow rate at which the meter will operate within some specified uncertainty or error limit. Obviously, the minimum flow rate depends on the limit chosen. Usually, this accuracy limit is set at ± 1.0%. Generally the minimum flow rate depends on the magnitude of the zero offset. The minimum flow rate can also be expressed in terms of a "standard" flow rate by making the appropriate pressure, temperature and compressibility corrections.

3.4.7 Pulsation Effects

In a number of measurement applications (e.g., compressor stations), the flow may be pulsating instead of steady. Frequently this can be rectified by placing the meter farther from the pulsation source or by adding a pulsation damper, but sometimes this is not possible. Thus, it may be important to know whether the magnitude of the error due to pulsating flow conditions is significant. In theory, pulsating flow should cause no significant error since the results are averaged over many measurements. Errors could occur if the pulsating flow is synchronized with the transducer firing rate.

3.4.8 Loss of Path

The loss of one or more paths in a multipath ultrasonic meter should cause the meter to generate an alarm, but continue to operate. The accuracy of a meter operating without all paths active will likely be reduced. The amount of the reduction in accuracy is specific to the meter design, the path lost and the compensation method. It may also be influenced by the flow characterstics of the specific installation.

3.5 Field Checks

3.5.1 General

The most commonly applied field checks are the visual inspection and speed-of-sound test. Operational meters measure the speed of sound in the gas. If the gas composition, pressure and temperature are accurately known, this measured speed of sound can be compared with a calculated speed of sound based on A.G.A. Report No. 8 as indicated in Section 3.1. Good agreement indicates that the transit-time measurement and one length measurement of the spool piece are within acceptable limits.

3.5.2 Visual Inspection

In visual inspections, the meter bore and transducer ports should be inspected for accumulation of solids, erosion or other damage that would affect meter performance.

3.5.3 Maintenance and Inspection Frequency

The ultrasonic meter should alert the operator when a problem occurs with the operation of the meter, and general inspection of the meter should not be necessary until an alarm condition exists. At dirty gas installations, periodic inspections can be established prior to expected alarm conditions to prevent their occurrence. The existence of an alarm condition does not mean that all flow measurement is lost, since the ultrasonic meter can continue to function with the loss of all but one of the path measurements.

4 Evaluation of Measurement Performance

The performance of the ultrasonic flow meter is constantly verified through the meter's self-diagnostic software. In addition to verifying that the meter is operating properly, the diagnostic software can attach a level of confidence to the flow measurement. The ultimate goal of the self-diagnostics is to verify that the measurement is accurate without the periodic inspections associated with conventional metering systems. It is far better to identify poor measurement conditions at the time of metering rather than wait and then try to correct corrupted data. The self-diagnostics also allow an operator to identify the cause of a metering problem, or at least have a good idea of the problem before going to the site, thus reducing maintenance or down time. This section will discuss the role of diagnostic software in evaluating meter performance and describe the major issues that can affect meter performance.

There are many levels of diagnostics in the ultrasonic flow meters — some very simple and others very complex. It may seem confusing because the conversations can become bogged down with discussions about signal detection, frequency content, timing, flow profiles, statistics or just about any other topic. In reality, the subject of diagnostics is straight-forward once one understands the different levels of diagnostics and the reason these levels exist. The next section will describe some of those levels, starting with the simplest and working toward more complex ideas.

Who or What is the Diagnostician?

Ultrasonic flow meters produce an alarm and an alarm ID code when the processing unit determines that a condition necessary for proper measurement has not been met. These conditions are often identified by setting limiting minimum and maximum values for diagnostic functions. For example, if the meter is used in a natural gas service in which the natural gas speed of sound is always known to remain between 1,400 ft/sec and 1,500 ft/sec, alarm limits may be chosen to indicate an extraordinary event. Another type of example, one which gauges the performance of the meter's components, is amplifier gain setting (the amount of power required by the system to raise the transducer signal level to a usable voltage). If the meter normally requires 70 dB to 100 dB, an alarm may be set at 120 dB to indicate the meter is working outside its normal settings. This may be an indication the transducer has weakened or an electrical component is not working properly. In most cases, the diagnostic tests can be changed, customized or eliminated entirely. As the data base of experience grows, new diagnostics can be added.

Simple Diagnostics: Is the Meter Working?

The simplest diagnostic is a reasonability check. If the meter is reading a reasonable number and if the meter doesn't have any obvious mechanical or electrical defects, it is considered working. A simple contact alarm, 0/1, with very relaxed diagnostic tests will suffice for this case. Recall from the previous paragraph that alarm conditions do not need to change in order to use a discrete alarm; however, the alarm ID code may not be read without further action. A serial link is needed to receive the alarm ID code.

Ultrasonic Signal Diagnostics

All flow information in ultrasonic flow meter is derived from transit-time measurements of ultrasonic signals traveling through a moving gas. One of the most critical aspects of the ultrasonic flow meter diagnostic software is to evaluate the individual ultrasonic signals to determine if the signal is acceptable for an accurate transit-time measurement. If there is a problem with the ultrasonic signals themselves, the transit-time measurement and, therefore, the flow measurement will be incorrect. It is impossible to state what an ultrasonic signal should look like in general, but essentially the signal needs to appear as expected by the receiver and processing software (recall digital meters use software to achieve signal detection).

Individual transducers have their own characteristics, similar to each human voice or ear, and the software must be able to handle some variation. When variations from the norm become too large, the system may experience detection problems. A simple example of a detection problem is cycle skipping. In older analog meters, the threshold detection technique would determine a detection point by choosing a zero-crossing after a voltage threshold had been reached by the signal. Unfortunately, the signal amplitude sometimes changes due to pressure changes and the threshold is crossed by a different portion of the ultrasonic signal or at a different cycle. The transit time would then be one period (1/f) different from the previous transit time. At 100 kHz, the transit-time difference would be 10 microseconds, resulting in an appreciable error of several percent. This particular detection problem can be identified by checking speed-of-sound measurements among different paths.

An example list of specific diagnostic tests has been included, but a few of the more common signal effects are discussed here for reference. These effects do not necessarily cause a measurement problem, since the goal of good detection software is to eliminate the need for extremely stable or predictable signals.

4.1 Signal Amplitude

The amplitude or strength of the ultrasonic signal (voltage on an oscilloscope) depends on just about every aspect of the measurement system. Even analog systems eventually employed automatic gain control because the effect is so widespread. Some transducers are stronger than others, especially special designs (wet gas, corrosives, etc.). Pressure is directly related to acoustic impedance in gases and, therefore, controls the amount of coupling between a gas and the transducer. Higher pressures are generally associated with stronger ultrasonic signals. Meter size and path length will change the amplitude of the signal because of spreading and signal scattering within the gas. Very large meters have weaker signals. Particulates or liquids in the gas may scatter the signal and weaken it. Dirt on transducer faces may weaken the signal. Temperature also has some effect on the ultrasonic signal strength.

4.2 Pulse Shape

A pulse's shape is important because the detection point within the pulse must be well-defined. The shape of any pulse is determined by the frequency content of the pulse: generally, the broader the bandwidth of the transducer, the narrower the pulse. Ultrasonic flow meters use fairly broad-band transducers in order to produce pulses with well-defined front edges that simplify detection. Much could be said about the design of these transducers. Suffice it to say that volumes have been written on the subject, and it still isn't clear that anyone can predict the output of a complicated transducer before testing it. The pulse shape can be affected by anything that distorts the signal. Flow rate itself has some effect on the pulse shape. At high flow rates, the signals tend to be pulled apart by shear within the flow profile. Irregular flow patterns may change the pulse shape. Edge effects from the meter body itself on outer paths or in small meters may alter pulse shape. Near-critical gas components, such as CO_2, can selectively attenuate certain frequencies within the ultrasonic signal and, therefore, change its shape.

4.3 Noise

When ultrasonic signals contain a high level of noise, it becomes more difficult to identify the pulse from the transmitting transducer; therefore, the transit-time measurement is in jeopardy. Noise is only a problem when it is ultrasonic, and it may be either gas-borne or direct (through the meter body). It may be further characterized as either synchronous or nonsynchronous to the firing pulse.

Direct noise is usually generated by the transmitter itself, but for some reason the signal elects to travel though the meter body rather than, or in addition to, through the gas. Since the speed of sound in steel is some 10 times greater than in a typical gas, the signal though the body arrives at the receiver before the gas-borne signal, and then echoes throughout the meter body for a long period of time. The cause of direct noise is usually an unintended coupling between the transducer element and the meter body by a liquid or solid material. Transducers and mounts should be designed to provide poor coupling into the body. The effectiveness of a particular design will vary with operating conditions, and direct coupling may still occur. Direct noise can then be eliminated only by removing the unintended coupling.

A common source of gas-borne noise is a pressure reduction within the gas pipeline. Ironically, "quiet" valves and regulators are especially noisy in the ultrasonic spectrum because the audible quietness is achieved by shifting the energy of the sound to a higher frequency (above 50 kHz). Gas-borne noise may be overcome with signal processing techniques. Signal averaging, or "stacking," is a technique that eliminates nonsynchronous noise extremely well in steady flowing conditions. Essentially, several ultrasonic wave forms are added together and the sum-wave form is divided by the number of signals added to produce the average-wave form. The noise in the wave form will tend to add to zero since it is random, while the signal from the transducer will accumulate in the same wave form position. The signal-to-noise (S/N) ratio can be made arbitrarily large if enough samples are taken and if the transducer signal is not moving (steady flow). Work has begun within the natural gas industry to study and reduce the level of noise from quiet valves and regulators that are in the ultrasonic flow meter range.

The power level of the ultrasonic transducer is significant in noisy applications because the signal level directly affects the S/N ratio. In almost every discussion on noisy applications, someone will ask, "Well, why don't you just increase the power to the transducer?" The answer is multifaceted, but safety is the main reason the power to the transducer may be limited. Since the transducer is in direct contact with the gas within the pipeline, some method must be used to control any ignition possibility in the event of a transducer failure. Most operators consider the inside of the pipeline to be a Division I area, and some require the transducer to be intrinsically safe. The intrinsically safe requirement limits the amount of power that can be used to drive the transducer and, therefore, limits the initial signal level and subsequent S/N ratio. In cases where intrinsic safety is not required or other methods, such as explosion-proof certified transducers, are accepted for internal pipeline safety, the power levels may be increased. The power levels may also be increased (depending on the design of the metering facility) if the transducer is *outside* the pressure boundary; that is, coupled to a buffer or flange where said buffer or flange is part of the pressure boundary. Higher power levels make it easier to check out and dry-calibrate a spool piece in air or other gas at atmospheric pressure.

4.4 Batch Diagnostics

Individual transit-time measurements are normally not used to calculate a flow rate. Sets of transit-time measurements, or "batches," are used to calculate flow rates. Typical batch sizes are from 8 to 32 sets of transit times. By using an average value for a batch, the output of an ultrasonic flow meter is more steady than if a single pair of transit times is used. The ultrasonic flow meter is also more forgiving, since a few rejected individual signals (see signal diagnostics) do not trigger a flow-rate alarm and the batch is simply evaluated on a smaller number of transit times. Of course, if the total number of individual signals rejected is very high, an alarm will be generated.

The batch diagnostics are statistical. As an example, assume a batch size of 32 for a four-path meter. The total number of transit-time measurements would be $4 \times 2 \times 32 = 256$, which provides a good base for the calculation of statistical information. A few simple examples of significant statistics should prove meaningful. The deviation from the norm value within any transit-time batch is important. For steady flow, the transit times all may be within 0.1 microsecond; for unsteady flow, they may vary by a few microseconds. The upper and lower extremes for transit-time measurements compared with the upper and lower extremes in the delta transit times are significant. A strong indicator of pulsations would be a wide variation in transit times, but a narrow variation in the delta transit times. Cycle skipping may also be detected by examining the batch statistics among different paths. Recall that speed of sound can be measured by the ultrasonic flow meter and the measurement should be equal on all four paths. If the transit times reflect a different speed of sound for one of the paths, the cause should be investigated. Flow-profile irregularities may also be identified by using the batch statistics. Equal speeds of sound in combination with irregular velocity measurements may indicate flow-profile irregularities.

Just as in ultrasonic signal diagnostics, the batch diagnostics needed will depend somewhat on the user and application. For higher accuracies, the requirements are more stringent. For simple check measurement or control, the diagnostics should be relaxed to avoid unimportant alarms. Compressor stations require a slightly different setup; for example, relaxed limits on the transit-time variations due to pulsation. All of these numbers are available and, in some cases, are logged at the request of the user.

Diagnostic Message Block Example

The following is an example of a portion of the information available through one manufacturer's diagnostic message block. This block of data demonstrates the level of information available and how messages are relayed to the user.

Message Block Example (transmitted by serial communications to a flow computer):

Register	Item Name
62.	STATA
63.	STATB
64.	STATC
65.	STATD
66.	STYSTAT
67.	A1FAIL
68.	B1FAIL
69.	C1FAIL
70.	D1FAIL
71.	A2FAIL
72.	B2FAIL
73.	C2FAIL
74.	D2FAIL

Detailed explanation of codes in message block:

62 - 65, STAT A...D, Chord status definition (for chord A, B, C, D)

0 = no error
bit 0 set = reject signal if noise level exceeds limit.
bit 1 set = reject signal if S/N ratio below limit.
bit 2 set = reject signal if measurement quality check failed.
bit 3 set = reject signal if speed of sound out of range.
bit 4 set = reject signal if delta time check failed.
bit 5 set = reject signal if span check failed.
bit 6 set = reject signal if polarity check failed.
bit 7 set = reject path if flow-profile check failed.
bit 8 set = reject signal if peak pulse width exceeds limit.
bit 9 set = reject signal if signal quality below limit.
bit 10 set = flow change indicator.
bit 11 set = reject path if intra-chord quality check out of range.
bit 12 set = reject path if speed-of-sound deviation out of range.
bit 13 set = path is manually set to be inactive.
bit 14 set = path failed.

66, SYSSTAT, General system status

0 = no error
bit 1 set = pulse accumulator error.
bit 2 set = processor RAM error.
bit 3 set = program memory error.
bit 4 set = EEPROM error.
bit 5 set = DSP program memory failure.
bit 6 set = DSP X memory error.
bit 7 set = DSP Y memory error.
bit 8 set = number or operating paths below minimum.

67 - 74, A...D FAIL 1..2, Number of failures per batch

A...D designates which path in the multipath meter.

1 or 2 designates which direction ultrasonic pulse travels (upstream or downstream).

5 Error Analysis

The principles for calculating an estimate of the uncertainty in the measurement are laid down in ISO 5168 and ISO 7066-1.

Three different kinds of factors may be distinguished as sources of error.

- physical: related to the velocity profile of the flow
- mechanical: related to the geometry of the acoustic path
- electronic: related to the transit-time measurement

Usually errors are classified as being either systematic or random. On the other hand, in statistical terms two concepts are defined to describe the properties of a measuring instrument: bias B and standard deviation σ. The root-sum-of-squares error e is given by

$$e = \sqrt{B^2 + \sigma^2} \qquad \textbf{(20)}$$

where B denotes the bias or systematic error and σ is the standard deviation of the random errors.

5.1 Bias

Because bias is a systematic error and not a random one, it can be reduced only by proper design, construction and installation of the instrument, not by averaging. In practice, it is the most important kind of error. Bias occurs if the actual flow does not match the model that underlies the computation of the velocity from the measured travel times or if the parameters used for the computations deviate from the actual geometrical configuration. Bias can only be reduced by proper installation of the instrument and not by averaging, because the error is systematic and not random. For instance, for the velocity profile to closely approximate an axially symmetric form, sufficiently long straight upstream and downstream pipe lengths are necessary.

5.1.1 Factors Relating to Geometry

The diameter of the conduit (roundness, wall thickness) may differ from its nominal value or from its value at the time of calibration because of expansion due to temperature or pressure. Then path lengths will also be influenced. To get an impression of the magnitude of these effects, a small example is presented here.

The volumetric flow rate can be described by combining equations (1), (17) and (18) to give the following expression

$$Q = \frac{\pi D^2}{4} W \frac{L^2}{2X} \frac{(t_U - t_D)}{t_U t_D} \qquad \textbf{(21)}$$

The effect of changes in geometry on the reported flow rate can be obtained by forming a ratio of the previous equation for the different conditions. By eliminating all the common terms, the ratio reduces to

$$\frac{Q_1}{Q_0} = \left(\frac{D_1}{D_0}\right)^2 \left(\frac{L_1}{L_0}\right)^2 \left(\frac{X_0}{X_1}\right) \qquad \textbf{(22)}$$

where the subscripts 0 and 1 indicate the measurements at a reference condition and at a new condition, respectively. Consider an ultrasonic flow meter consisting of a pipe with radius R_0 at gas pressure P_0 (at which it is assumed perfectly accurate), wall thickness w, modulus of elasticity E and coefficient of thermal expansion α. For an increase in gas pressure to P_1, and assuming a purely elastic deformation, the new radius R_1 of the pipe is found as

$$\frac{R_1}{R_0} = 1 + R_0 \frac{P_1 - P_0}{E\, w} \qquad \textbf{(23)}$$

There is also a change in the axial (X) measurement for the spool piece, which is influenced by the types of support provided for the installation. For this example, the effect of pressure on the axial deformation is ignored. Assume for a particular spool piece numerical values are $E = 2\text{x}10^5$ N/mm^2 ($29\text{x}10^6$ lb/inch^2), $R_0 = 154$ mm (6.06 inch), $P_1 - P_0 = 50$ bar (5 N/mm^2, 725 psi) and $w = 8.4$ mm. (0.33 inch), then

$$\frac{R_1}{R_0} = 1.000458 \qquad \textbf{(24)}$$

Ignoring the change in the X measurement and assuming a 45-degree path angle along the spool diameter (X_1=X_0=D_0), the path lengths can be determined from the spool geometry as L_0=435.5777 mm and L_1=435.6775 mm. From equation (22), the ratio of flow rates is then 1.00137. Therefore, from this change of geometry, an error of -0.137% is estimated for this 50 bar (725 psi) increase of gas pressure.

The changes in geometry due to thermal expansion can be expressed as:

$$\frac{R_1}{R_0} = \frac{L_1}{L_0} = \frac{X_1}{X_0} = 1 + \alpha\, \Delta T \qquad \textbf{(25)}$$

which leads to the following expression for the change in reported flow rate due to a change in the temperature of the spool piece.

$$\frac{Q_1}{Q_0} = (1 + \alpha\, \Delta T)^3 \qquad \textbf{(26)}$$

For a rise of temperature of ΔT=50° C (90° F), using $\alpha = 14\text{x}10^{-6}$ °K^{-1} ($7.78\text{x}10^{-6}$ °F^{-1}) for the thermal expansion, the ratio of flow rates is then 1.0021, which indicates an error of -0.21%. This result is independent of pipe radius and wall thickness of the instrument.

If the pipe is assumed to be round, but actually is not, a systematic error will be the result. This error may be either positive or negative, depending on the orientation of the acoustic path with respect to the distorted part of the cross-section. Usually the deviation from a perfect circle is less than 0.1% diameter variation.

The roughness of the inner wall surface of the conduit is another geometrical factor, which actually influences the velocity profile in the boundary layer near the wall. For practical applications, the wall may be considered smooth as long as its equivalent sand roughness is less than about 25 μm (0.001"). Steel appears to be very sensitive to corrosion when exposed to air after being exposed to high-pressure natural gas for some time. Therefore, the wall roughness may rapidly increase when an instrument is removed from a gas line, unless it is protected either by a coating or by a thin film of oil. An increased wall roughness may cause velocity-dependent reading errors.

5.1.2 Factors Relating to Calculation Techniques

The weights w_i applied to the path measurements may be constant values, defined for the chosen mathematical method of approximate integration, or they may be empirically determined as a result of flow testing and modeling and vary as a function of the measured path velocity. For a given number and position of acoustic paths, the bias in using a particular set of weighting functions is influenced by the actual condition and shape of the velocity profile. Evaluation of the cause and magnitude of this bias requires extensive testing of the flow meter under a variety of flow conditions.

5.1.3 Errors in the Time Measurement

Non-fluid contributions to the measured transit time may include time delay in cables, electronics and the front face of transducers; internal computational precision; and the influence of the ambient condition on the electronics. There can also be flow-induced timing errors resulting from turbulence, swirl and pulsation, and time delays in the transducer pockets.

Transducer time delays can cause velocity offset errors (due to differential time delay) and relative velocity errors (due to absolute time delay). The measurement of the transit times t_U and t_D may be corrupted by electronic phase differences between the upward and downward path. Since this is equivalent to a differential time delay t_e, a velocity offset error (v_e) will be the result, approximately given by

$$v_e \approx \frac{c^2}{2} \frac{t_e}{X} \tag{27}$$

which, for a given differential delay, will be smaller for larger pipes.

From equation (1) it is clear that the measured flow velocity does not depend on the velocity of sound. Therefore, small errors in the velocity of sound do not have a significant systematic influence on the accuracy of the measured flow velocity.

5.2 Variance

The influence of random errors can be reduced by repeating the measurements and averaging them. Although normally variance has less consequence than bias, it is important for the interpretation of observed differences and in determining the sampling time for calibration of the instrument.

Geometrical factors hardly contribute to the variance of the measurements. Measurement of the transit times t_U and t_D is only slightly affected by analog electronic noise and the effects of time-quantization. In modern instruments the transit time of the pulses is typically measured using quartz-controlled digital electronics, which reduce the influence of analog electronic noise. Because the finite time interval of the clock chosen is sufficiently small, the effects of quantization noise can be neglected when operating well above the minimum flow rate. This leaves turbulent velocity variations, both in time and along the acoustic path, as the main cause of the random errors in ultrasonic measurement of a stationary flow. The variation of the speed of sound, because it is slow, can be neglected as compared with turbulent velocity variations. Equation (11) shows that the measured velocity actually is an average along the acoustic path. Thus, the longer the acoustic path length, the more the turbulent fluctuations are averaged out, resulting in greater accuracy. Therefore, not only can a systematic error like velocity offset be reduced, but also the random variations can be reduced in larger pipes as compared with smaller pipes. The remaining influence of random errors is reduced by repeating the measurements and averaging them. For a fixed averaging period of one second and a sufficiently high repetition rate, the standard deviation σ_V of the measured velocity V can be written as

$$\sigma_v = S_0 + S_1 V \qquad \textbf{(28)}$$

where S_0 and S_1 are constants that depend on the electronic timing accuracy and on the geometry of the acoustic path. This relation expresses a lower bound for the achievable standard deviation in ultrasonic velocity measurement. Dividing both sides by V yields an expression for the standard deviation of the relative error

$$\frac{\sigma_V}{V} = \frac{S_0}{V} + S_1 \qquad \textbf{(29)}$$

This expression clearly shows that as V approaches zero, the relative error becomes arbitrarily large, given a fixed length of measuring time. Practical calibration procedures, therefore, should increase the measuring time at low velocities as compared with higher ones.

6 Calibration

6.1 Dry Calibration

Dry calibration (without fluid flow) involves the accurate measurement of the dimensions of the spool piece, which include the spool diameter D, and for each of the paths, the dimensions L and X. Errors in the dimensions directly affect the measurement accuracy. The expected uncertainty of a multipath meter that has been dry-calibrated is claimed to be 1% or better. However, there are not enough data to demonstrate this conclusively. If higher accuracy is needed and/or traceability to a national standard is required, a flow calibration is recommended.

In addition to the measurements of the spool-piece geometry, the time delays can be measured for a specific set of electronics and transducers.

One method is to mount two transducers in a pressurized test cell. The separation of the transducers must be accurately known. The chamber is filled with a gas (usually nitrogen) for which the velocity of sound is known. In this test cell, a zero-flow condition is present. The actual transit time of the signals in the fluid can be calculated from the ratio of path length and speed of sound. Because the transit times for upstream and downstream are equal (zero flow), t_U and t_D can be calculated. The ultrasonic system measures times that include time delays in the electronics, transducer, cables, etc. The time delays are calculated as the subtraction of the calculated values from the measured values. This method requires accurate knowledge of the velocity of sound in the test cell. Any errors in the velocity of sound in the test cell affect the flow-meter performance, similar to errors in L and D. This causes a systematic shift of the performance curve, since errors in the assumed velocity of sound of the gas in the test cell cause a systematic offset in the applied time delays. The same method can be used for testing individual transducers and can be used in the field as a check on the initial calibration.

Another method, which does not require knowledge of the velocity of sound, can be used for determining the time delay in the electronic cables and transducers. The method requires a setup in which the transit times of a pair of transducers can be measured at two known and different path lengths at zero-flow conditions. The measurement must be performed under the same gas conditions for both path lengths. Since the transit-time measurement includes the same delay time for both path lengths, a system of two equations with two unknowns (time delay and speed of sound) can be formed and solved explicitly.

6.1.1 Velocity Distribution

Depending on the calculation method used, multipath ultrasonic meters may or may not require that an assumption be made for the velocity distribution. When required, the k-factor for a particular path can be calculated, based on the Reynolds number and the assumed flow profile (or through prior extensive flow testing). However, errors in the k-factor are not considered in a dry calibration. In a multipath meter arrangement, the multiple paths, path positioning and the calculation technique considerably reduce the measurement uncertainty and the effect of non-ideal velocity profiles.

6.2 Flow Calibration

A flow calibration can be used to reduce errors resulting from inaccuracies in path length, path angle, pipe diameter and path location. The mean ratio between the output signal and the flow velocity (sometimes called "meter factor") can be determined by a flow calibration. The calibration should be performed in a way to ensure that the test rig does not influence the test results. This incorporates a steady, fully developed velocity flow profile, free from swirl and pulsation. Generally these requirements can be achieved by using sufficient straight lengths of pipe upstream and downstream from the meter tube. If necessary, an upstream flow conditioner may be installed. As a minimum, the manufacturer's reference to the installation conditions must be observed.

The calibration should be performed as closely as possible to the Reynolds number of the actual application. During the calibration, the meter output, which may be via serial communications or a frequency signal, is compared with one or more reference instruments. If using analog output, the resolution of the conversion to a digital signal needs to be considered.

To improve accuracy, the calibration should be conducted according to good laboratory practice and in accordance with methods recognized by international standards (e.g., ISO 4185, ISO 8316, ISO 9300). Any flow calibration has a degree of uncertainty, depending on the methods of calibration and the facility. It is determined by the random and systematic errors in measurement of the flow velocity and by the random and systematic errors of the laboratory.

The uncertainty of the laboratory can be as low as 0.2% to 0.3%.

The calibration should be made over a statistically significant number of runs and over a range of flow velocities. A common practice is to calibrate at least 6 or 10 velocities, logarithmically spaced over the meter range, taking the mean of at least three measurements, of 100 seconds, at each velocity. In the lower part of the range, the number of measurements may be increased to 5 or 10. In determining the number of repeat points at each flow condition, the variability of the instrument under test should be considered, so that the random errors are sufficiently averaged and the remaining difference with respect to the calibration standard is predominantly the bias of the instrument under test.

6.3 Calibration Facilities

A significant problem is the current lack of facilities capable of calibrating these meters, which typically need to be calibrated at very high flow rates and pipeline pressures. Cost of the calibration may be a significant portion of the cost of the meter, and the test may only cover the lower end of the meter capacity.

Facilities to calibrate meters larger than 12" in diameter are virtually nonexistent.

6.4 Transducer Replacement

Ultrasonic meters are fitted with pairs of electrical ultrasonic transducers. In the event that a transducer must be removed due to malfunction or damage, single transducers or pairs of transducers are replaced, depending on the recommendations of the specific manufacturer. The procedure consists of two major steps, one mechanical and one computational. The mechanical replacement of the transducers follows a procedure that is specific to the manufacturer's model and transducer type.

The effect on calibration of changing transducers in the field is still being studied.

6.4.1 Mechanical Procedure

Most ultrasonic meters use flanges to connect the ultrasonic transducers to the meter body. The configuration of the transducer might include either isolation ball valves or insertion mechanisms. The purpose of the ball valve or insertion mechanism is to allow the transducer replacement procedure to be performed without relieving the pressure of the meter body. In other words, the transducers can be replaced without "blowing-down" the metering section of the pipeline. This can be a significant design advantage when working with offshore systems where space is at a premium.

Another type of transducer assembly utilizes a buffer rod as part of the fixed-pressure boundary, which allows the "transducer" portion *outside* the pressure boundary to be removed and replaced without the use of an isolation valve and without an insertion mechanism. This possibility exists because removal and replacement of the transducer portion do not influence or jeopardize the pressure boundary.

6.4.2 Computational Procedure

The computational procedure required for the replacement of transducers varies with the manufacturer. Methods may include mechanically and electrically characterizing each transducer pair, or manufacturing all transducers identically so that no changes are required in the computational setup.

As was discussed in Section 6.1, the electronic time delay associated with an individual transducer pair can be measured prior to installation. When using this method, the value of the delay time for the replacement transducer pair is entered into the electronics of the ultrasonic meter at the time of transducer replacement and used in the flow calculation.

The goal of the replacement is to change transducers without changing the calibration of the meter. A change in calibration can occur both because the overall length of the transducer path can change and because the electrical characteristics of each transducer may be different. The effect of the electrical characteristics on the measurement is a change in the delay time, and thus a change in the detection point in the signal-processing algorithm.

The physical length of the transducer pair can be measured in parts, including the transducer length, the ball valve length and the meter-body cavity length. The total path length is a sum of those numbers. When transducer pairs are changed, the new lengths associated with the transducers can be entered into the electronics of the ultrasonic meter and used in the flow calculation.

6.4.3 Verification

The verification of a successful field replacement can be accomplished by using several confidence checks. The following general checks can be used.

1. Verify that the velocity of sound, as measured by all transducer pairs, agrees to within a specified range (typically 1%).
2. Verify that the velocity of sound, as measured by all transducer pairs, is reasonable for the given gas composition.
3. Verify that the flow profile has the same shape and weighting as before the exchange.
4. If possible, achieve absolute zero flow and verify that the meter is reading an acceptable zero flow [typically less than 0.003 m/sec (0.01 ft/sec)].

7 Recommendations

7.1 Industry

The lack of calibration facilities for these meters needs to be addressed. While it is convenient to assume that the meters are inherently accurate from dry-calibration, this has not yet been proved to be the case. These meters have the potential to be very high-volume meters, and small errors can quickly multiply. Facilities that can economically calibrate the meters and that are recognized as being accurate will allow the users of ultrasonic meter technology to benefit from it, instead of turning it into a potentially costly mistake.

7.2 Users

Users of the ultrasonic meters described in this technical note include gas producers, transporters and buyers. Care should be taken by these parties to ensure that the meter will meet the requirements of the application. It is likely that a flow calibration will be a requirement in a large number of cases, until such time as it has been established that this is not required.

Users also need to get involved in advocacy efforts for research and development and should be describing potential benefits of the technology to the manufacturers, so that future generations of the meters will provide maximum benefit.

7.3 Manufacturers

Manufacturers should continue to develop the technology and strive to provide increased reliability and consistent accuracy. The data-gathering and analysis necessary to increase the level of trust in the technology will need to come in large part from the manufacturers.

7.4 Researchers

Industry-funded research, as well as research funded by individual users, needs to augment work done by the manufacturers. Research on various piping configurations will increase the confidence of all parties in the technology.

ULTRASONIC METER RESEARCH LITERATURE AND ACTIVITIES

The following is a compilation of past, present and planned research and development work associated with transit-time ultrasonic flow meters. The list includes only published research by both manufacturers and users from around the world.

It is evident that work related to ultrasonic flow measurement is divided into two groups: pure research to advance theoretical concepts and methodologies, and evaluatory work — new product evaluations or product performance evaluations. In most instances, because of the proprietary sensitivity of evaluatory work, results are not published or released to the public. Therefore, detailed information regarding evaluatory work is difficult to obtain. In comparison, theoretical or nonproprietary information and results are relatively easy to obtain and make up the majority of the test work listed herein.

Table 1, Ultrasonic Meter Research Literature, is a compilation of pertinent ultrasonic measurement publications available to the general public. Those research papers that are sponsored by privately funded research programs (not for general release) are not included in this listing.

Table 2, Ultrasonic Meter Research Activities, is a list of research work that has been identified in Europe, the U.S.A. and Canada. The research work listed is related to custody-class measurement or the advancement of custody-class measurement.

TABLE 1

ULTRASONIC METER RESEARCH LITERATURE

SL. NO.	TITLE	AUTHOR(S)	SPONSORS	DATE
1	Ultrasonic Flowmeters, Transactions of the Institute of Measurement and Control; Part 1, 3(4) pp. 217-223 (Oct. - Dec. 1981); Part 2, 4(3), pp. 2-24 (Jan. - Mar. 1982)	L.C. Lynnworth	IEEE	1981
2	Ultrasonic Flowmeter Offers New Approach to Large Volume Gas Measurement	W.D. Munk	Columbia Gas System Service Corp.	1982
3	Ultrasonic Measurement of Volume Flow Independent of Velocity Distribution	H. Lechner	LGZ Landis and GYR AG, Switzerland	1982
4	An Ultrasonic Flowmeter for the Accurate Measurement of High Pressure Gas Flows	M.E. Nolan J.G. O'Hair	British Gas	1983
5	Calculated Turbulent-Flow Meter Factors for Nondiametral Paths Used in Ultrasonic Flowmeters	A.M. Lynnworth L.C. Lynnworth	Panametrics	1983
6	Further development of the British gas ultrasonic flow-meter	M. E. Nolan, M.C. Gaskell and W.S. Cheung	British Gas	1986
7	Installation Effects on Single and Dual - Beam Ultrasonic Flowmeters	P. Hojholt, Danfoss A/S	NEL	1986
8	Recent progress in the developmens of a four path ultrasonic flow meter for the gas industry	M.E. Nolan J.G. O'Hair	London Research Station/Daniel	1988
9	Ultrasonic Flowmeters for the Gas Industry	M.E. Nolan	NEL	1988
10	Test Results of Daniel 4 - Path Ultrasonic Flowmeter	K. Van Dellen H. De Vries	Gasunie	1989
11	Ultrasonic Gas Flow Meter with Corrections for Large Dynamic Metering Range	J. Delsing	Lund Institute of Technology	1989
12	An Integral Ultrasound Transducer/Pipe Structure for Flow Imaging.	H.Gai, M.S. Beck and R.S. Flemons	UMIST	1989
13	Renovation of the Export Stations of Gasunie	P.M.A. van der Kam, A.M. Dam, K. Van Dellen, A.J. Algra, J. Smid.	Gasunie	1990
14	Renovation of Export Metering System	A.M. Dam K. Van Dellen	Gasunie	1990
15	The Effects of Upstream Disturbances on the Uncertainty of Reading from High Pressure Ultrasonic Meters	R.J.W. Peters	NEL	1990
16	Ultrasonic Flow Meters	P&GJ Staff	Pipeline & Gas Journal	1990
17	Acoustic Flowmeter Field Test Results	R.A. McBane, RL. Campbell and E.G. DIBello	GRI	1991
18	A Three-path Ultrasonic Flow Meter with Fluid Velocity Profile Identification	G.A. Jackson, J.R. Gibson and R. Holmes	U of Liverpool	1991
19	Developments in Ultrasonic flow Metering	Karst van Dellen	NSFMWS, Norway	1991

SL. NO.	TITLE	AUTHOR(S)	SPONSORS	DATE
20	Practical Experiences Using Ultrasonic Flowmeters on High Pressure Gas	J.L. Holden R.J.W. Peters	Daniel Industries	1991
21	A new multi-beam ultrasonic flow-meter for gas	A. Lygre, T.Folkestadt, R. Sakariassen, D. Aldal	Statoil	1992
22	Modeling in the Analysis of Installation Effects on Flowmeters	Jouko E. Halttunen Esa A. Luntta	U of Tampere, Finland	1992
23	Effects of Flow Disturbance on an Ultrasonic Gas Flowmeter	E. Hakansson J. Delsing	Lund Institute of Technology	1992
24	Multipath Ultrasonic Gas Flowmeters Show Promise	K. van Dellen	Daniel Industries	1992
25	Chirp Excitation of Ultrasonic Probes and Algorithm for Filtering Transit Times in High-Rangeability Gas Flow Metering	T. Folkestad K.S. Mylvaganam	IEEE	1993
26	Designing of Ultrasonic Flowmeters	V.I. Filatov	FILAT - Russia	1993
27	Gassonic-400 & P. Sonic & Q. Sonic Ultrasonic Gas Flow Meters	J.G. Drenthen F.J.J. Huijsmans	Stork Servex B.V.	1993
28	The Mathmatical Model of Multipath Ultrasonic Flowmeter for Open Channel	S. Walus, A. Thomas, J. Zelezik	Inst. of Automation, Poland	1993
29	Ultrasound Gas-flow Meter for Household Application	A. Von Jena, V. Magori W. Russwurm	British Gas	1993
30	A Secondary Standard Ultrasonic Gas Flow Meter	Noel Bignell	CSIRO, Austrailia	1994
31	Custody Transfer Ultrasonic Flow Meter: Q Sonic	J. Drenthen	Stork Servex B.V.	1994
32	Synthesis Report on the Ultraflow Project, Installation Effects on Ultrasonic Flowmeter Calibrations	JIP	JIP	1994
33	Ultrasonic Gas Flow Meters Used for Storage Measurement	K. van Dellen	Daniel Industries	1994
34	Ultrasonic Meter Experience	A. Bergman R. Wilsack	TCPL	1995
35	Ultrasonic Metering - A Field Perspective	J. Beeson	NorAm	1995
36	Recent Developments Enhance Status of Ultrasonic Metering	J. Beeson	NorAm	1995
37	Ultrasonic Meters Prove Reliability on Nova Gas Pipeline	M. Rogi	NGTL	1995
38	Flare Gas Ultrasonic Flow Meter, Proc. 39th Annual Symposium on Instrumentation for Process Industries, pp. 27-38, ISA 1984	J.W. Smalling L.D. Braswell L.C. Lynnworth D.R. Wallace	Panametrics	1984
39	Ultrasonic Gas Flowmeters M&C (Measurements & Control) 29, pp. 92-101 (Oct. 1995)	L.C. Lynnworth	Panametrics	1995
40	Measurement of Turbulent Flow Rate	I.A. Kolmakov, A.G. Safin	Metrologiva (publication - USSR)	1987

TABLE 2

ULTRASONIC METER RESEARCH ACTIVITIES

SL. NO.	RESEARCH	SPONSORS	DATE
1	Installation Effects - 8" Multipath Meters - Daniel, Instromet	NGTL	1995
2	Contamination Effects - 8" Multipath Meters - Daniel, Instromet	NGTL	1995
3	Operational Testing - Multipath Ultrasonic Meters	TCPL	1995
4	Operational Evaluation - 24" Multipath Meters - Daniel, Stork-baseline to AGA - 3 Multirun Orifice Meter Station	NGTL	1996
5	Offshore Custody Transfer Service	Statoil	1995
6	Ultrasonic Flowmeters in Disturbed Flow Profiles	BP, Statoil, CMR	1994
7	6" and 12" Daniel Meter Tests	Norsk Hydro	1994
8	Installation Effects - Multipath Meters	GRI @ SwRI	1995
9	4" Multipath Meters in Non-ideal Flow	NEL	1994
10	6" Daniel - Test	K-Lab	1988
11	6" Daniel - Test	K-Lab	1990
12	12" Fluenta - Calibration	Fluenta @ K-Lab	1991
13	12" Daniel - Calibration	Statoil @ K-Lab	1992
14	24" Daniel - Calibration	Statoil @ K-Lab	1992
15	24" Daniel - Calibration	Statoil @ K-Lab	1993
16	6" Daniel - Calibration	Norsk Hydro @ K-Lab	1993
17	12" Daniel - Calibration	Norsk Hydro @ K-Lab	1993
18	20" Daniel - Functional tests	Statoil @ K-Lab	1993
19	20" Europipe - Valve Noise Influence	Statoil @ K-Lab	1994
20	6" Fluenta - Calibration	Statoil @ K-Lab	1994
21	12" Fluenta - Test Installation effects	Gasunie @ Bernoulli Lab	1993
22	12" Fluenta - Tested	Ruhrgas @ Lintorf Lab	1993
23	Stork - Endurance Test	Gasunie	1994

SL. NO.	RESEARCH	SPONSORS	DATE
24	Q Sonic - Swirl	Gasunie	1993
25	Bi-Directional Test - Daniel	Oklahoma Nat Gas	1994
26	Daniel Test	British Auckland	1994

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