Manual of Petroleum Measurement Standards Chapter 5.8

Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters

SECOND EDITION, NOVEMBER 2011

energy API®

AMERICAN PETROLEUM INSTITUTE

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Contents

Contents

Page

Introduction

This document describes methods for the installation and operation of Ultrasonic Flow Meters (UFMs) when they are used to measure liquid hydrocarbons.

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

Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters

1 Scope

1.1 General

This document defines the application criteria for UFMs and addresses the appropriate considerations regarding the liquids to be measured. This document addresses the installation, operation, and maintenance of UFMs in liquid hydrocarbon service.

1.2 Field of Application

The field of application of this standard is the dynamic measurement of liquid hydrocarbons. While this document is specifically written for custody transfer measurement, other acceptable applications may include allocation measurement, check meter measurement, and leak detection measurement. This document only pertains to spool type, multi-path ultrasonic flow meters with permanently affixed acoustic transducer assemblies.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API *MPMS* Chapter 4.5, *Master-Meter Provers*

API *MPMS* Chapter 4.8, *Operation of Proving Systems*

API *MPMS* Chapter 6.1, *Lease Automatic Custody Transfer (LACT) Systems*

API *MPMS* Chapter 6.2, *Loading Rack Metering Systems*

API *MPMS* Chapter 6.4, *Metering Systems for Aviation Fueling Facilities*

API *MPMS* Chapter 6.5, *Metering Systems for Loading and Unloading Marine Bulk Carriers*

API *MPMS* Chapter 6.6, *Pipeline Metering Systems*

API *MPMS* Chapter 6.7, *Metering Viscous Hydrocarbons*

API *MPMS* Chapter 13.1-1985, *Statistical Concepts and Procedures in Measurement*

API *MPMS* Chapter 21.2, *Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters*

3 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1
acoustic path
The path that the acoustic signals follow as they propagate through the measurement section between the acoustic transducer elements.

3.2
acoustic transducer
A component that produces either an acoustic output in response to an electric stimulus and/or an electric output in response to an acoustic stimulus.

3.3
axial flow velocity
The component of liquid flow velocity at a point in the measurement section that is parallel to the measurement section's axis and in the direction of the flow being measured.

3.4
flow-conditioning element
A device for reducing swirl and velocity distortions.

3.5
K-factor
pulses per unit volume.

3.6
meter run
The section of piping which includes the upstream flow-conditioning section, the flow meter and the downstream flow section.

3.7
pulse scaling
Scaling performed in the SPU so that the meter produces a set number of pulses proportional to volume.

3.8
SPU
signal processing unit
Electronics system, including power supplies, microcomputer, signal processing components and ultrasonic acoustic transducer excitation circuits, may be housed in one or more enclosures mounted locally or remote to the meter.

3.9
transit time
Measurement of the time interval associated with transmission and reception of an acoustic signal between acoustic transducers.

3.10
UFM
ultrasonic flow meter.

4 Design Considerations

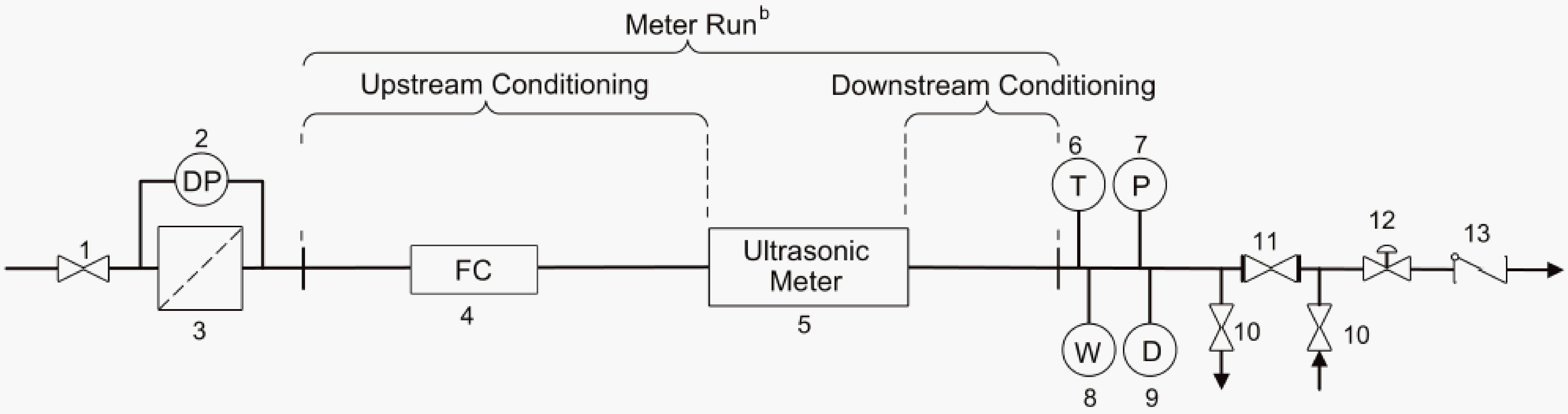
4.1 The design of an Ultrasonic Flow Meter (UFM) run shall take into account the following considerations.

4.1.1 The meter run design shall consider the user's minimum and maximum flow rates, Reynolds number, temperatures and pressures. Additionally, it shall consider the following physical properties; viscosity, relative density, vapor pressure, and corrosiveness. Operating within the linear flow range of the UFM based on the specific application is desirable.

4.1.2 Temperature devices, temperature test thermowells, pressure and density sensing devices shall be installed to accurately represent the actual metering conditions. Immediately downstream of the meter run is the preferred location (see Figure 1).

4.1.3 Transit time UFMs typically do not require the use of strainers since they have no mechanical moving parts that could be adversely affected by debris. Strainers may be required to protect associated equipment, including meter provers or pumps or to provide a means of keeping flow conditioners free of debris.

4.1.4 If air or vapor is present in the flowing stream, eliminators shall be provided to minimize measurement error (see Figure 1).



Key

1. block valve[a]
2. differential device[a]
3. strainer and/or air eliminator[a]
4. flow conditioning element[a]
5. ultrasonic flow meter
6. temperature measurement device
7. pressure measurement device
8. temperature test well
9. densitometer[a]
10. prover take-off valve
11. double block and vent valve
12. flow control valve[a]
13. check valve[a]

Notes

[a] Element may not be required.

[b] See Section 7.1, Flow Conditioning.

Figure 1—Typical Elements of a Single UFM Installation

4.1.5 The meter run design shall ensure that each meter is liquid filled under all operating conditions. Placement of the meter(s) at high points in the system shall be avoided. UFMs may be installed in any position or plane. However, care shall be taken to ensure that the acoustic transducers are not located on the top or bottom of the pipe to minimize the effects of air or sediment. The meter's installation orientation should be in accordance with the manufacturers' recommendation.

4.1.6 For multiple meter runs, see *MPMS* Chapter 6 (all sections) for meter system design considerations.

4.1.7 Steps shall be taken to minimize the amount of water in the fluid being measured. Depending on the flow regime, the acoustic properties of the oil, the water droplet size and distribution, and the amount of water, UFMs may become less accurate because paths may become inoperable. Due to the number of possible variables, a specific % water limitation cannot be given. Consult the UFM Manufacturer for guidance on this limit. The meter diagnostics may be useful in understanding the performance of the meter. See Section 12.

4.1.8 The design shall comply with all applicable regulations and codes.

4.1.9 Meters shall be adequately protected from excessive pressure through the proper use of pressure relief devices. This kind of protection may require the installation of surge tanks, expansion chambers, pressure-limiting valves, pressure relief valves, and/or other protective devices.

4.1.10 The operating pressure in the meter run shall be maintained sufficiently above vapor pressure.

4.2 The following equation may be used to calculate the minimum backpressure.

Consult the meter manufacturer for maximum pressure drop to determine the total backpressure required in Equation 1.

$$P_b \geq 2\Delta p + 1.25 p_e \tag{1}$$

where

Pb is the minimum backpressure, pounds per square in gauge (PSIG);

Δp is the pressure drop across the meter run;

p_e is the equilibrium vapor pressure at operating conditions, pounds per square in absolute scale (PSI).

For liquids with vapor pressure greater than atmospheric pressure, a backpressure greater than 20 psi above the liquid vapor pressure at operating conditions is sufficient.

5 Bi-directional Flow

5.1 If the meter is utilized in bi-directional flow:

— both inlets of the meter shall conform to the upstream requirements;

— a meter factor shall be determined for each direction.

5.2 If a meter is utilized more often in one flow direction than the other, temperature, pressure and/or density instrumentation shall be located downstream of the meter run relative to this direction.

6 Selecting a Meter and Accessory Equipment

6.1 Consideration shall be given to the following items.

6.1.1 The class and type of piping connections and materials and the dimensions of the equipment to be used.

6.1.2 The minimum and maximum operating flow rates.

6.1.3 The minimum and maximum operating viscosity of the liquids to be measured.

6.1.4 The minimum and maximum operating Reynolds number. See Annex D.

6.1.5 The space required for the installation of the metering and proving system.

6.1.6 The acceptable pressure drop across the meter run. Though most UFMs have minimal or no pressure drop, consideration should be given to the pressure drop created by the flow conditioning element.

6.1.7 Metallurgy, elastomers, coatings and other components are compatible with the process fluid.

6.1.8 The effects of erosive and or corrosive contaminants on the meter and the quantity and size of foreign matter, including abrasive particles, which may be carried in the liquid stream.

6.1.9 The minimum and maximum ambient and process temperatures.

6.1.10 Possible depositions such as wax, asphaltenes, or other precipitants that may affect the performance of the UFM.

6.1.11 The size and type of prover and method of proving. Unidirectional piston pipe provers with external detector switches (small volume prover) require special consideration to achieve repeatability. See Annex B.

6.1.12 Maintenance, costs, and spare parts that are needed.

6.1.13 Requirements and suitability for security sealing, auditing, and/or reporting.

6.1.14 Interface requirements for communicating meter pulses, diagnostics and alarms to other electronic devices as needed.

6.1.15 Power requirements.

6.1.16 Regulatory and contractual requirements.

7 Installation

7.1 General

Applicable industry standards and manufacturer's recommendations shall be followed when installing the meter run components.

7.2 Flow Conditioning

Flow-conditioning elements intended to reduce swirl or velocity profile distortion may be required. The design shall ensure appropriate flow conditioning upstream and downstream of the meter. Typically, straight pipe lengths of 10 pipe diameters with a flow conditioning element upstream of the meter and 5 pipe diameters downstream of the meter provide effective conditioning, unless the meter manufacturer's experience and recommendations along with flow research support different lengths (see Figure 1). Special attention should be given to the length of the upstream flow conditioning section when a flow conditioning element is not used. Headers and out of plane 90 degree turns located upstream of the meter run may induce swirl that impacts the performance of the UFM.

The inside diameter of the meter run piping shall be the same as the inlet-outlet of meter. Welds shall be internally ground smooth and all gaskets shall be installed to not protrude into the pipe. Methods to ensure proper internal alignment are recommended.

The effects of different piping configurations or flow-conditioning elements on the flow-conditioning installation requirements has not been fully evaluated; therefore, consult the manufacturer for design considerations.

Meter proving repeatability, as well as the derived meter factor, may be affected by the flow-conditioning design; including the type and location of the flow-conditioning elements. For example, in cases where the meter cannot be proved immediately after meter run servicing, the original rotational position of the flow-conditioning element shall be maintained since experience has shown this can affect meter performance (i.e., meter factor).

7.3 Valves

7.3.1 Valves require special consideration since their location and performance can affect measurement accuracy.

7.3.2 The preferred location of the flow or pressure-control valves should be downstream of the meter run and prover takeoff valves. Valves should be capable of smooth operation to prevent shocks and surges.

7.3.3 Valves, particularly those between the meter and prover (e.g. the stream diversion valves, drains, and vents) require leak proof shutoff, which may be provided by a double block-and-bleed valve with telltale bleed.

7.4 Electronics

The UFMs electronics system, including power supplies, microcomputer, signal processing components and ultrasonic acoustic transducer excitation circuits, may be housed in one or more enclosures mounted locally or remotely to the meter and is referred to as the Signal Processing Unit (SPU). It shall be designed and installed to meet the applicable hazardous area classifications. The SPU shall operate over its entire specified environmental conditions within the meter performance requirements.

7.5 Electrical

7.5.1 The electrical systems shall be designed and installed to meet the applicable hazardous area classifications.

7.5.2 The pulsed data transmission systems shall be designed to provide appropriate fidelity and security. See API *MPMS* Ch. 5.5.

7.5.3 UFMs and their interconnecting cables are all susceptible to Electromagnetic Interference (EMI). Since the electrical signals of the UFMs are at relatively low power levels, care must be taken to avoid interference generated from nearby electrical equipment and wiring. UFMs employ various materials and methods to provide shielding against EMI. Cable jackets, rubber, plastic and other exposed parts shall be resistant to ultraviolet light, oil and grease.

7.5.4 Poorly designed cathodic protection and grounding systems can be sources of potential interference with the UFM signals.

7.5.5 An un-interruptible regulated power supply (UPS) shall be provided for continuous meter operation.

8 Meter Performance

8.1 Meter factor shall be determined by proving the meter at stable operating conditions (i.e., essentially constant: flow rate, density, viscosity, temperature, and pressure). API *MPMS* Ch. 4.8, may provide guidance in this area. Users typically determine the acceptable deviation limits of these operating conditions.

8.2 Proving is primarily a function of regulatory and contractual requirements and typically standard company operating procedures. Proving conditions shall be as close to the actual metering conditions as practical. The essential purpose of proving is to confirm the meter's performance at normal operating conditions. Most UFMs provide a means of adjusting for the changes in the geometry of the meter caused by changes in body temperature. By employing this feature, reproving necessitated by temperature changes may be reduced or eliminated. Questions often arise concerning the differences between proving or calibrating a meter in a laboratory (bench) versus in-situ (field). These two proving locations can produce different results and cannot necessarily be interchanged without introducing measurement error.

8.2.1 In-situ proving is normally preferred because it verifies the meter's accuracy under actual operating conditions. Operating conditions can affect a meter's accuracy and repeatability. In-situ proving at stable operating conditions compensates for variations in performance caused by flow rate, viscosity, density, temperature, pressure, as well as flow conditions, piping configurations, and contaminants.

8.2.2 Laboratory proving is normally not preferred because laboratory conditions may not duplicate the piping and operating conditions. While there are more measurement uncertainties associated with laboratory proving, under certain conditions, it may provide the best alternative.

9 Proving Accuracy and Repeatability

9.1 Proving accuracy can be affected by the delayed manufactured flow pulses from a UFM. These delayed manufactured flow pulses can lead to a bias error in the calculated meter factor depending upon the magnitude of the flow rate change that occurs during the proving run and the duration of the prove run. This potential problem is explained in detail in Annex C.

Master meter proving of an ultrasonic meter as per API *MPMS* Ch. 4.5 may be applied, provided the additional uncertainty typically associated with master meter proving is acceptable to the parties involved.

9.2 Proving run repeatability is used as an indication of whether the proving results are valid.

9.2.1 Some UFMs may produce a non-uniform pulse output, which can exhibit a wide span of repeatability when proved. See Annex B for detailed explanation.

9.2.2 It should be noted that proving run repeatability might not fall within the typical 5 run, 0.05 % span of repeatability. However proving runs shall repeat within the guidelines of API *MPMS* Ch. 4.8.

10 Operation and Maintenance

10.1 System Setup

UFM configurations can be unique to specific applications. Before the meter is put into service, ensure that the meter is installed in the correct location and measurement application. Verify that configuration parameters and settings conform to the manufacturer's documentation.

10.2 Hardware

When multiple meters are installed, care must be taken to match the correct SPU with the correct meter body. The SPU contains factory information unique to each meter body such as; dimensional data, acoustic transducer path lengths, performance data etc. (see Figure 2).

10.3 Operation of Metering Systems

UFMs shall be operated within the manufacturers' specified flow range, operating conditions and fluid properties.

10.4 Setting the UFM Response Time

To minimize meter factor bias errors that can be introduced during proving, it is important that the flow pulse from the SPU respond as quickly as possible to changes in flow rate. The SPU may provide configuration settings that can be used to adjust the UFMs responsiveness to changes in flow rate. These configuration settings vary between manufacturers, but typically fall into the following three categories.

a) Sample interval—the time period between ultrasonic flow rate samples.

b) Number of samples—the number of ultrasonic samples processed for each flow measurement update.

c) Pulse output adjustment—amount of damping or filtering of the flow measurements that produce the pulse output signal.

NOTE Not all manufacturers provide items a), b), and c).

It is recommended that item a and/or item b above be set to the minimum as recommended by the manufacturer. Item c above should be set to zero or minimum as recommended by the manufacturer.

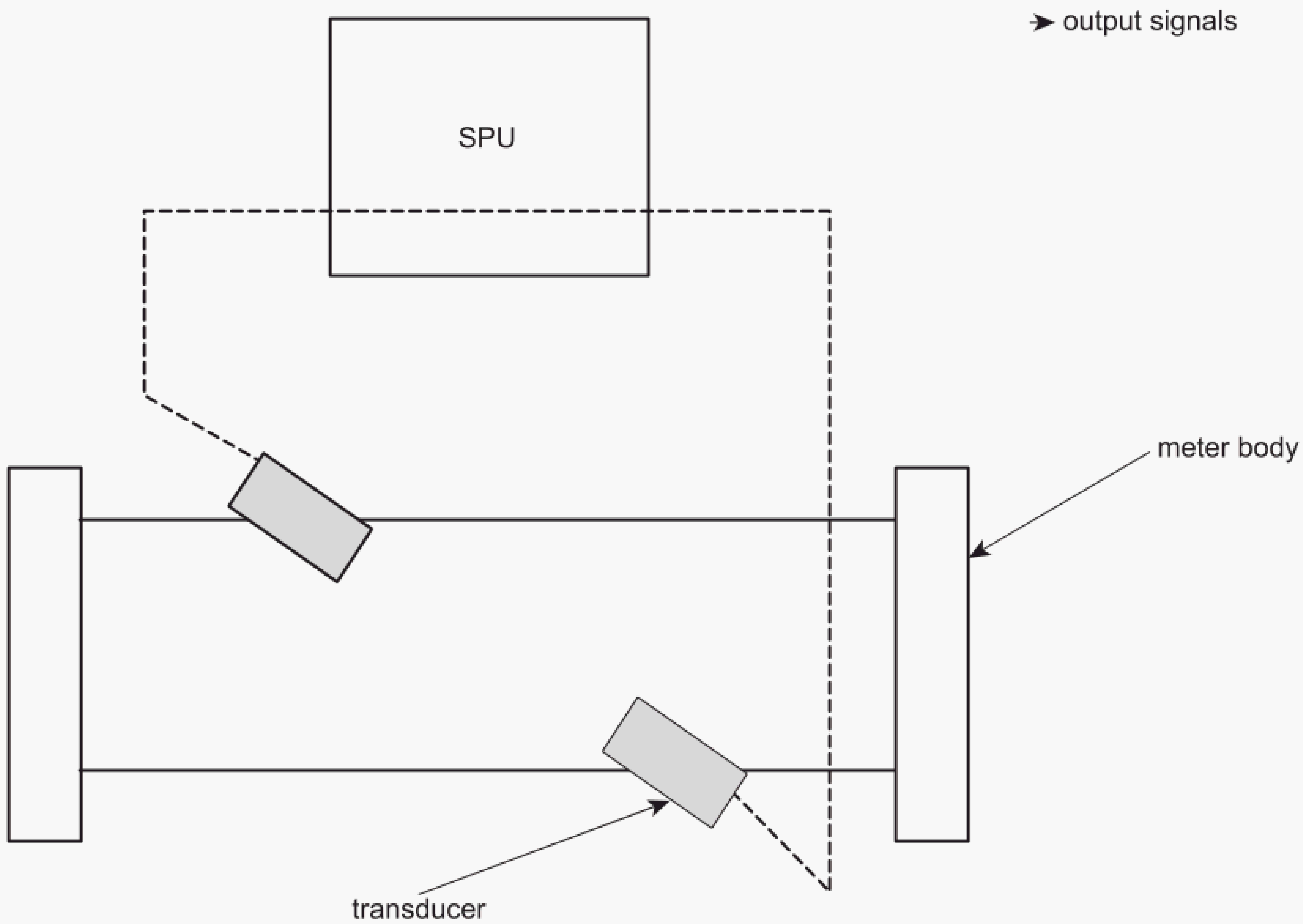


Figure 2—UFM Main Components

When changes are made that affect the UFM's speed of response to flow rate changes, i.e. by modifying the sample rate, sample time period, pulse output filtering or damping, the UFM shall be re-proved.

10.5 Pulse Scaling

The SPU calculates a flow rate and determines an appropriate pulse output rate to represent that flow rate. The relationship between the pulse output rate and the flow rate is configurable in the SPU. Pulse scaling relates the pulses to the volume measured and can be used to equate a pulse output frequency to a given flow rate, or can be used to define the number of pulses to be output by the UFM per measured volume. When configuring pulse scaling, the pulse frequency output should not exceed 90 % of the maximum allowable input frequency of the accessory equipment receiving the pulse signal.

10.6 Methods of Controlling Correction Factor

There are various methods of applying the meter factor to indicate the actual quantity measured through the meter. The adjustment from indicated to actual quantity can be made by varying the meter factor or K-factor. These factors can reside in either the UFM SPU or accessory equipment or be applied manually. The preferred method is to apply a meter factor in the accessory equipment because of its audit trail capability. It is important that the method selected be used consistently.

A UFM is calibrated by the manufacturer to determine one or more calibration coefficients that are entered into the UFM SPU. These coefficients, although adjustable, should remain unchanged. Any factors changed that can affect the quantities measured by the meter must be retained in the audit trail. In applications where the flow rate varies during normal operation, it may be desirable to determine meter factors over a range of flow rates. The various meter factors can then be used to linearize the output from the UFM at varying flow rates. If the meter is used to measure bidirectional flow, a meter factor should be developed for each direction.

If the pulse scaling is changed the meter shall be reproved.

10.7 Zeroing the Meter

Zeroing an UFM is a procedure that involves checking the output while the meter is blocked-in. Under these conditions, and if the output of the meter does not indicate zero flow, then the manufacturer's (re-) zeroing procedure shall be followed. Whenever the meter is re-zeroed, it shall be reproved.

Normally, a UFM does not require manual zeroing. However changes or replacement of acoustic transducers, electronics or acoustic transducer cables shall require that the meter zero be checked and if necessary (re-) zeroing procedures shall be followed. In any case, changes or replacement of acoustic transducers, electronics or acoustic transducer cables shall require the UFM to be reproved.

11 Auditing and Reporting Requirements

11.1 General

API *MPMS* Ch. 21.2 fully addresses the auditing and reporting requirements of a generic Electronic Liquid Measurement (ELM) system. The audit requirements of an ELM system using an UFM are similar, except for the addition of specific configuration and setup parameters contained in the SPU which must be auditable and securable.

11.2 UFM Configuration Parameters and Settings

The UFM manufacturer shall provide the ability to identify primary UFM components and document the meter's configuration parameters and settings that affect the flow meter's output.

On initial installation, the meter's firmware/software configuration should be documented and tracked for validation purposes. A change in checksum, for example, would indicate a change in meter configuration and probably meter performance.

A UFM shall provide an audit trail of the meter's configuration parameters and settings that affect the meter's output(s).

11.3 Alarm, Event Logs

There are no special requirements for the alarm, event and error logs for ELM systems using a UFM other than those specified in API *MPMS* Ch. 21.2.

12 Diagnostics

Certain parameters can be monitored based on the specific application. Many of these parameters are monitored within the UFM and when these parameters fall outside the preset limits a diagnostic alarm will be generated. In most cases, the troubleshooting process would require the evaluation of more than one of the parameters below. Using various methods such as trending plots can help to understand the performance status of the UFM over time and how these parameters compare to the original factory setup and the onsite startup conditions. The complete troubleshooting process however would require evaluating these diagnostics parameters and process operating conditions combined. The parameters below are typical of those that may be accessed via a serial data interface or other means.

— **Gain**

Gain is a measure of the amount of amplification required to achieve the desired signal amplitude for processing. High gain indicates greater attenuation of the signal. High gain can be caused by the presence of solids or gas in the liquid, high viscosity, water/oil mixtures and possibly a weakening acoustic transducer to name a few. When the gain reaches maximum amplification (saturation) it is an indication that no signal is being transmitted and a diagnostic alarm will be generated.

— **Signal to Noise Ratio (SNR)**

The ratio of useful signal to noise as seen by each acoustic transducer along the acoustic path of a UFM. High SNR is beneficial to good measurement. A low SNR may indicate a potential acoustic transducer problem or process condition. A low SNR could be a normal signal strength and high noise possibly caused by improper grounding or electrical interference to name a few. On the other hand, a low SNR could be a low signal strength caused by the presence of solids or gas in the liquid, high viscosity, and water/oil mixtures to name a few.

— **Path Velocity Ratio**

The ratio of an individual path velocity to the average axial flow velocity. By comparing these path velocity ratios, changes in the flow profile can be determined. Asymmetric profiles can be an indication of flow disturbances such as swirl in the flow stream which can be caused by conditions such as debris in the strainer or in the flow conditioner.

— **Velocity of Sound Along Each Acoustic Path**

The distance between the acoustic transducers are known (path length) and therefore by knowing how long the signal takes to cross that distance, a velocity of sound measurement can be made. The approximate velocity of sound ranges for some liquids are shown below:

— Water = 4850 ft/sec;

— Sea Water = 4995 ft/sec;

— Brine = 5740 ft/sec through 6000 ft/sec;

— Refined Products = 2000 ft/sec through 4600 ft/sec (includes NGLs);

— Crude Oil = 4400 ft/sec through 5000 ft/sec;

— Propane = 2000 ft/sec through 2500 ft/sec;

— Iso Butane = 2200 ft/sec through 2800 ft/sec;

— Normal Butane = 3100 ft/sec through 3700 ft/sec.

By knowing the velocity of sound and comparing to what is determined by the meter, the velocity of sound on each path should be similar indicating a consistent product stream. Paths showing a change in velocity of sound may indicate a change of product in the stream. A velocity of sound variation from top to bottom of the meter could indicate a density gradient.

— **Flow Stream Turbulence (standard deviation of path velocities)**

The stability of the flow velocity along each path is an indication of the turbulence intensity within the flow stream. Some turbulence is normal due to friction effects or boundary layer (typically 2 % through 4 %). Higher turbulence levels can indicate partial blockages of upstream flow conditioners, changes in pipe wall roughness, and gasket protrusion to name a few.

— **Percentage of Accepted Measurements for each acoustic path**

A series of checks are performed for each acoustic path to determine if it is to be used for transit time measurement. The number of accepted signals used in a batch of samples is reported:

— **Alarm and failure indicators**

Depending on the UFM manufacturer, additional parameters may be available such as:

- spool temperature;
- fluid density;
- fluid viscosity;
- calculated Reynolds number.

Comparing lab determined diagnostic parameters to the same parameters when installed in the field may help identify field installation effects or other parameter changes. It is also recommended to compare these parameters periodically during meter operations.

13 UFM Security and Access

Configuration parameters and settings must be secured against tampering or unauthorized or un-documented changes. This may be achieved by using passwords and/or tamper proof seals or locks. (See API *MPMS* Ch. 21.2.)

Annex A
(informative)

UFM Measurement Principle

Ultrasonic transit time flow meters use acoustic transducers that can send and receive high frequency acoustic signals. The acoustic transducers are located in such a way that the generated acoustic signals will travel diagonally across the pipe. Transit time methods rely on the measurement of time intervals associated with transmission of acoustic signals across the pipe in opposing directions. This methodology is not synonymous with the Doppler ultrasonic technique that relies on the measurement of frequency shift in reflected acoustic energy.

The measurement is based on the fact that the acoustic signals that travel diagonally across the pipe in the direction of flow (downstream) will take less time to cross than the one traveling in the opposite (upstream) direction under flowing conditions. The time difference between the two acoustic signals is proportional to the average flow velocity along the acoustic path.

The acoustic signal that travels in the direction of flow (downstream) crosses the pipe in time (see Figure A-1):

$$t_{A>B} = \frac{L}{c + \bar{V}\cos\theta} \tag{A.1}$$

The acoustic signal that travels against the direction of flow (upstream) crosses the pipe in time:

$$t_{B<A} = \frac{L}{c - \bar{V}\cos\theta} \tag{A.2}$$

where

L	is the acoustic path length;
c	is the velocity of sound in liquid;
θ	is the angle the acoustic path makes with the pipe axis;
$\bar{V}$	is the average axial velocity in the pipe;
$A>B$	is the acoustic signal traveling from upstream to downstream;
$B>A$	is the acoustic signal traveling from downstream to upstream.

The average velocity is therefore determined by the following:

$$\bar{V} = \frac{L}{2\cos\theta} \times \frac{t_{B>A} - t_{A>B}}{t_{A>B} \times t_{B>A}} \tag{A.3}$$

Multiple acoustic transducers can be used to create multiple acoustic paths (beams) over the cross-section of the pipe in order to obtain more information about the flow velocity distribution (flow profile).

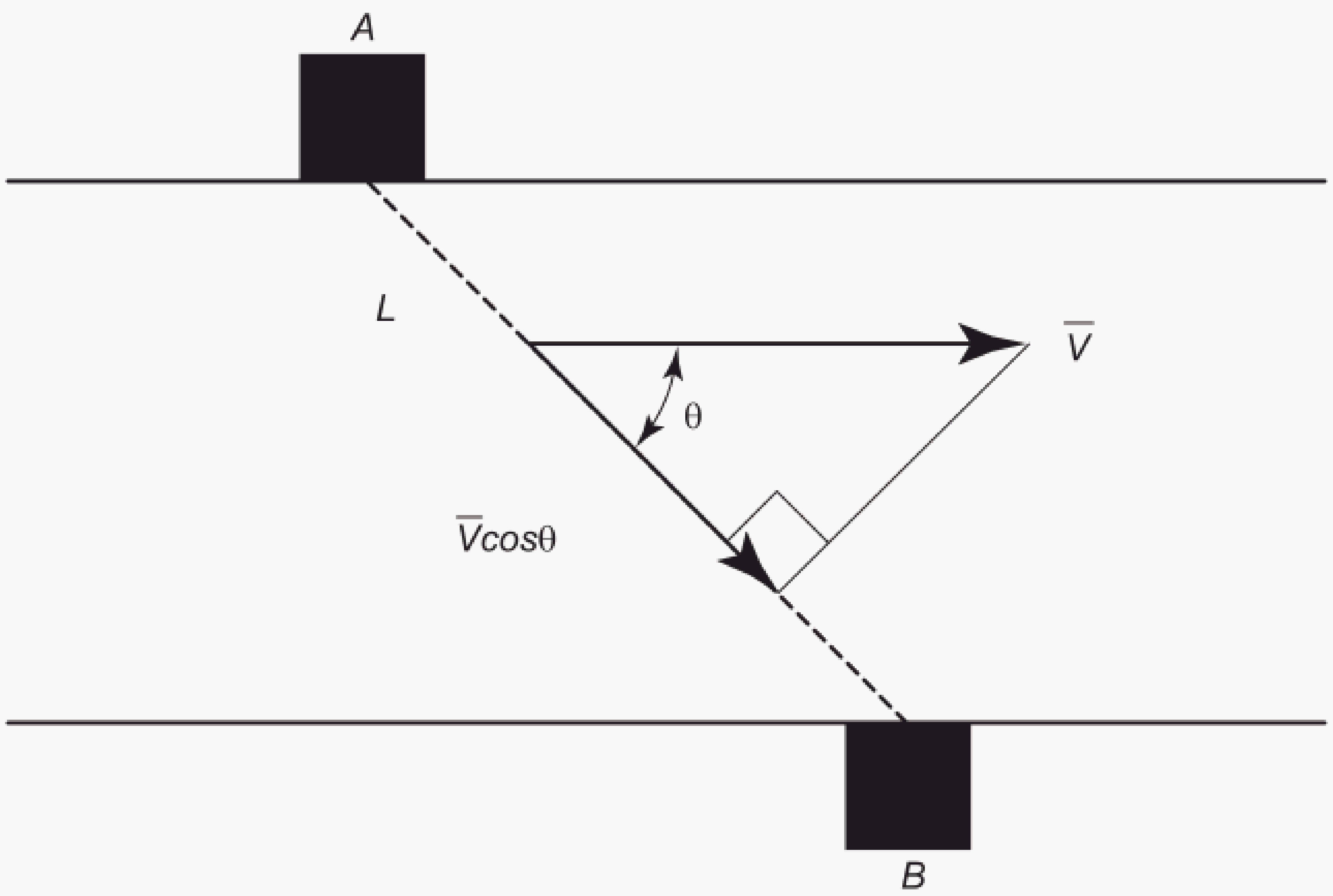


Figure A.1—UFM Transit Time Method

Typical Sequence of Operations

1) **Emission:** The SPU sends an electrical signal to the acoustic transducers (piezo electric crystal) that causes the crystal to generate an acoustic signal into the fluid.

2) **Reception:** The acoustic signal crosses the pipe and contacts an opposing acoustic transducer (piezo electric crystal) that vibrates in response to the acoustic signal, thereby generating an electrical output signal.

3) **Conversion:** The receiver circuit(s) in the SPU accepts these electrical signals for further processing.

4) **Signal treatment:** According to the manufacturer's algorithm, the SPU treats this data to obtain the $t_{A>B}$ and the $t_{B>A}$ values.

5) **Transit time method:** The SPU uses the difference between $t_{A>B}$ and $t_{B>A}$ to calculate the average fluid velocity along the paths, commonly using the transit time principle described above.

6) **Volumetric flow rate calculation:** Depending on the number of paths, their geometry, and the manufacturer's algorithm, the SPU uses the average velocity values to determine the volumetric flow rate.

7) **Output refresh:** The SPU repeats the fluid velocity measurement and produces various kinds of output that represent the measured volumetric flow rate and other measured or inferred values. Typically, these outputs are subject to programmable scaling, averaging and smoothing functions, as may be desirable to the user.

Solid particles, gas bubbles or water droplets may disturb the acoustic signal traveling through the fluid across the pipe. Typical disturbances are refraction, reflection, attenuation, and distortion. In these cases, the measurement along this path could be rejected according to the manufacturer's algorithm. Usually, low numbers of rejected measures will not impact the flow meter's accuracy. But above certain levels that are specific to each flow meter, the number of rejected measurements can have an impact on the flow meter accuracy, and in extreme cases can stop the meter's operation. Alarms may inform the user on the status of rejected measurements.

Annex B
(informative)

Verification and Validation of Meter Performance

The turbulent flow field in a pipe is complex and contains numerous turbulent eddies and non-axial velocity components.

Turbine meters and other mechanical flow measurement devices integrate this field through mechanical convergence and are not particularly influenced by minor changes in flow stability. Fluid acceleration into the rotor combined with rotor mass produces mechanical integration of the flow field. With turbine meters for instance, the resulting meter output signal exhibits little in the way of scatter from these “instantaneous” flow effects because of the inherent inertia of the measurement element. Data scatter, or variation in repeatability, of turbine meters is usually attributable to either sustained changes in global flow or to non-linear mechanical and inertial forces that occur during proof runs.

UFMs take snapshots of the fluid velocity along one or more sample paths. Each ultrasonic path is a line of sampling that produces time differentials and subsequent velocities as snap shots equal in number to the sample frequency for the sample period. For example, at 60 Hz, 60 flow rate measurements would be computed in one second.

Variations in velocity along each path are random as the turbulent eddies and variations in local flow that produce them are entirely random. Each sample will then vary from the mean velocity for a given sample period and the family of samples will be evenly distributed about the mean.

UFMs “see” not only the global axial velocity, but also all of the flow components, including the turbulent eddies resulting from fluid drag and mixing in the pipe.

Real time integration of the flow field, including both axial and non-axial components, results in a less well-behaved output and inherently more scatter. However, this scatter, because it is random, will be evenly distributed around the mean meter factor.

Verifying the performance of a UFM is not unlike verifying mechanical systems. However, because UFMs employ sampling methodology, they produce a greater degree of data scatter due to their ability to measure minute variations in velocity. UFMs may produce wider repeatability ranges for existing provers designed in accordance with industry standards than are typical for a mechanical device. Failure to be mindful of the evenly distributed nature of the data points about the mean meter factor will lead to errors in evaluation. A range exceeding 0.05 % in 5 runs does not mean that a UFM is defective, or that its meter factor cannot be established with the required uncertainty.

UFM performance verification can be ascertained by conventional means and to a level consistent with API *MPMS* Ch. 4.8, Table A-1 (shown below as Table B.1). The most conservative approach to accomplishing this level of repeatability relies on determining an acceptable prover volume. For instance, turbine meters can usually be successfully proven in 5 consecutive runs to within 0.05 % span of repeatability, which demonstrates ± 0.027 % or better meter factor uncertainty at a 95 % confidence level. Based on field data, UFMs may require a larger prover volume to achieve this same level of meter factor uncertainty. For applications where the use of a larger prover is not viable, master meter proving of an ultrasonic meter as per API *MPMS* Ch. 4.5 may be applied.

Given the larger prover volume that may be needed to verify a UFM to ± 0.027 % uncertainty, it follows that more than 5 proving runs may be required to verify the meter’s performance. Table B.1 provides the guidance for obtaining these results. Any of the number of runs chosen from the tabulation below will produce results that verify meter performance to ± 0.027 % uncertainty. There is no difference, in this regard, in a repeatability range of 0.05 % in 5 runs vs. a range of 0.12 % in 10 runs—they are the same. The operator is advised to select the appropriate number of runs, and span of repeatability, suitable for the prover volume available. Alternatively, the operator may simply increase the number of proof runs incrementally until the repeatability range falls within the limits of Table B-1. Experience with UFMs of several manufacturers using ball provers shows that the required meter factor accuracy is typically achieved with fewer than 10 to 12 runs, or with a prover volume 2 to 3 times larger than current industry standards for other types of meters such as turbines. Larger numbers of runs may be necessary if small volume provers are employed. Small volume provers that create flow disturbances can create non-repeatable proving results. Care shall be exercised when selecting and using small volume provers.

Table B.1—Proving an Ultrasonic Flow Meter

Repeatability = ((High Counts – Low Counts) / Low Counts) ×100		
Runs	**Repeatability [a]**	**Uncertainty**
3	0.02 %	± 0.027 %
4	0.03 %	± 0.027 %
5	0.05 %	± 0.027 %
6	0.06 %	± 0.027 %
7	0.08 %	± 0.027 %
8	0.09 %	± 0.027 %
9	0.10 %	± 0.027 %
10	0.12 %	± 0.027 %
11	0.13 %	± 0.027 %
12	0.14 %	± 0.027 %
13	0.15 %	± 0.027 %
14	0.16 %	± 0.027 %
15	0.17 %	± 0.027 %
16	0.18 %	± 0.027 %
17	0.19 %	± 0.027 %
18	0.20 %	± 0.027 %
19	0.21 %	± 0.027 %
20	0.22 %	± 0.027 %

[a] per API *MPMS*, Ch. 4.8, Table A-1 to achieve ± 0.027% uncertainty of meter factor.

$$a(MF) = \frac{[t(95, n-1)][w_{(n)}]}{(\sqrt{n})(D_{(n)})}$$

where

$a(MF)$ is the random uncertainty of the average of a set of meter proving runs;

$t(95, n-1)$ is the student "*t*" distribution factor for 95% confidence level and $n-1$ degrees of freedom (see Table 2 of API *MPMS* Ch. 13.1-1985, R2011);

$w_{(n)}$ is the range of values (high minus low) in the meter proving set;

n is the number of meter proving runs;

$D_{(n)}$ is the conversion factor for estimating standard deviation for *n* data points (see Table 1 of API *MPMS* Ch. 13.1-1985, R2011).

Example for 10 runs:

$t(95, n\text{-}1) = 2.262$

$w_{(n)} = 0.0012\ (0.12\%)$

$n = 10$

$D_{(n)} = 3.078$

Annex C
(informative)

Manufactured Flow Pulses and Their Impact on the Proving Process

Because the UFM uses an electronic sampling methodology to determine flow rate, the manufactured pulse train obtained from a UFM at any instant in time will represent flow (or volume throughput) that has already occurred (i.e., the manufactured flow pulses lag the measured flow). In order to optimize the flow measurement and accommodate unique installation effects, some UFMs can be configured to process a larger or smaller number of measurement samples, and/or slow the responsiveness of the flow pulse output with electronic filters. Increasing the number of measurement samples, or slowing the responsiveness of the pulse output will increase the time delay between the flow or volume represented by the manufactured flow pulses and the current flow or volume passing through the meter at a particular moment in time. In normal operation, delay between flow pulses and the actual measured flow has little impact on measurement accuracy if the correct meter factor has been used. However, during the proving process, delayed flow pulses may cause poor run to run repeatability and/or introduce a bias error in the calculated meter factor.

Poor repeatability and/or meter factor bias error can be the result of:

a) flow instability during the prover run;

b) flow disturbances that occur immediately before the displacer activates either of the detector switches.

Meter proving requires counting flow meter pulses that represent the actual volume that passed between the detector switches of the prover. When proving a UFM, some of the pulses counted represent a volume that has already occurred before the detector switch is activated.

Excessive time delay between the measured flow and the manufactured flow pulses can make the proving process more sensitive to flow rate changes that occur shortly before the displacer passes by the detector switches. While the time lag between manufactured pulses and actual measured volume is constant, the linear velocity of, and volume displaced by the prover displacer as it activates each of the detector switches, is ‘not’ constant if the flow rate is not identical.

To minimize any meter factor bias error, and/or to obtain the best possible span of repeatability results, it is important to ensure that:

1) the flow rate remains constant just before the first detector, and throughout each prove run; and

2) the time delay between the manufactured pulses and the actual measured flow is minimized in accordance with the manufacturers recommendations.

Because flow and pressure disturbances can occur with some prover types when the displacer is launched or the four way valve is cycled, it may be necessary to de-rate the prover’s maximum flow rate specification to attain item 1) above. De-rating the prover must increase the pre-run travel time to the first detector sufficiently to allow all manufactured pulses representing flow that occurred during the period of flow pulsation, caused by the displacer launch disturbance, to be output by the UFM before the first detector switch is activated.

Annex D
(informative)

Reynolds Number Performance Curve

Reynolds Number is a dimensionless number that quantifies the relationship between the inertial forces of the flowstream and the viscous forces of fluid flow through the pipe carrying the flowstream (see note below). Reynolds Number can be mathematically represented as:

$$Re = \frac{Dv\rho}{\mu}$$

where

D is the diameter of the pipe;

v is the average velocity of the flowstream;

ρ is the density of the fluid;

μ is the absolute viscosity of the fluid.

NOTE For purposes of this discussion, it is assumed that liquid petroleum typically behaves as a Newtonian fluid where the viscosity of the fluid is unaffected by the shear rate and the shear forces that exist when the fluid is in motion through a pipe are proportional to the velocity of the fluid.

When considering the velocity variations across the flowstream, it becomes apparent that the fluid velocity must be zero at the inside surface of the pipe, regardless of the velocity of the flowstream. And when the velocity of the flowstream is not zero, there will be a gradient of fluid velocities between the inside surface of the pipe and the center of the pipe, with the maximum velocity being at the center, provided there are no geometrically induced hydraulic influences, i.e. elbows, reducers, etc. and that the flow profile has had sufficient time to fully develop. See Figure D.1.

The shear force at any location within the pipe can be expressed as:

$$\tau = \mu\frac{dv}{dy}$$

where

τ is the shear force;

$\frac{dv}{dy}$ is the velocity gradient (y is the distance from the pipe wall).

While not expressed here, it can be shown mathematically that the velocity gradient takes a somewhat parabolic shape and that the Reynolds Number of the flowstream, along with the roughness of the pipe wall determines the thickness of the gradient. When the Reynolds Number is low (normally around 2,000), the inertial forces of the flowstream are constrained by the viscous forces and the velocity profile across the entire flowstream takes the shape of a bullet. At Reynolds Numbers higher than 8,000 to 10,000, the viscous forces are not sufficient to constrain the inertial forces and the flowstream becomes turbulent. At this point, the velocity profile of the center portion of the flowstream becomes somewhat flat The diameter of this flatter region increases as the Reynolds Number increases until the thickness of the gradient between the flatter region and the wall nears zero. See Figure D.2 looking left to right.

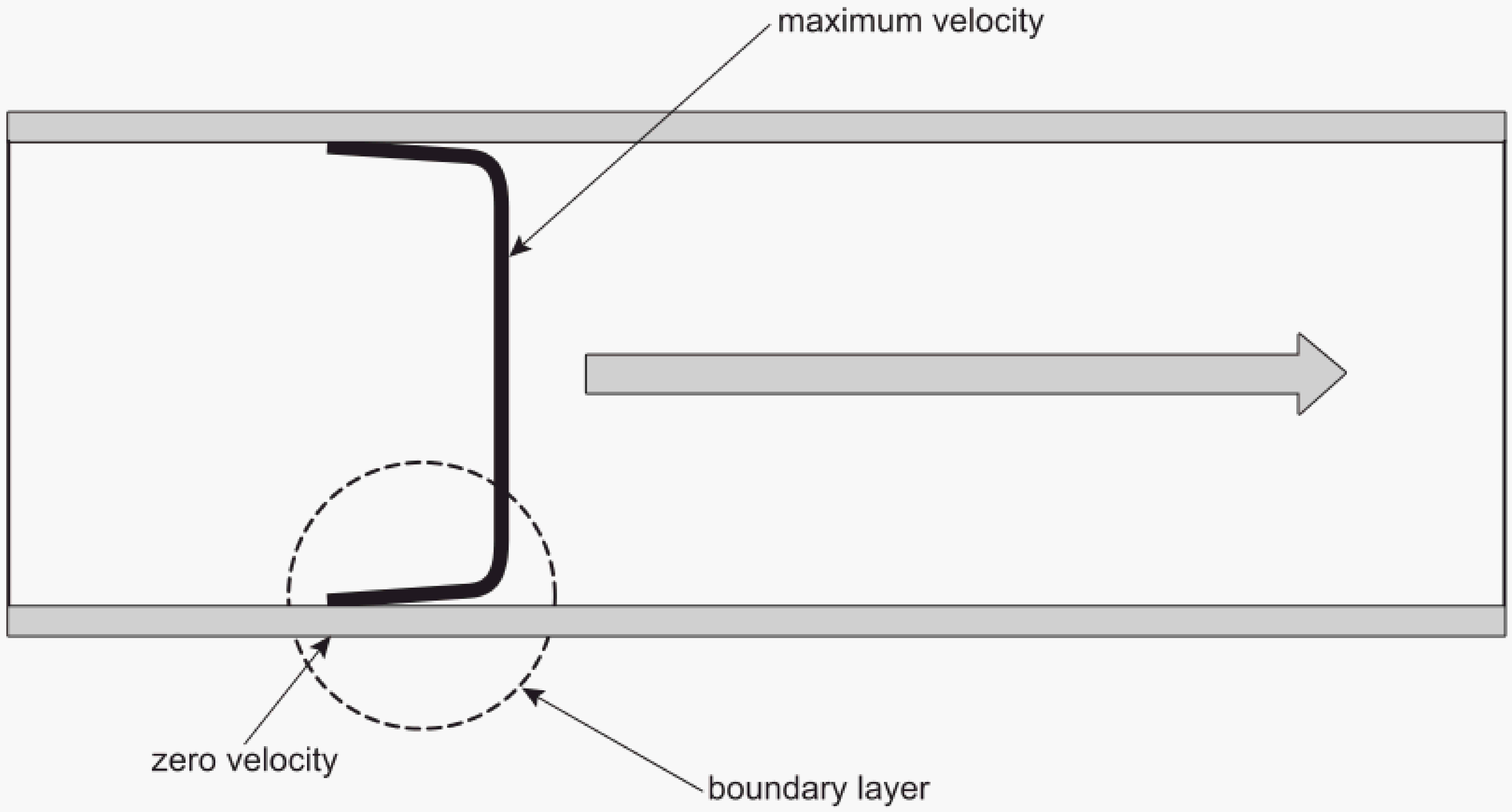


Figure D.1—Flow Profile and Boundary Layer

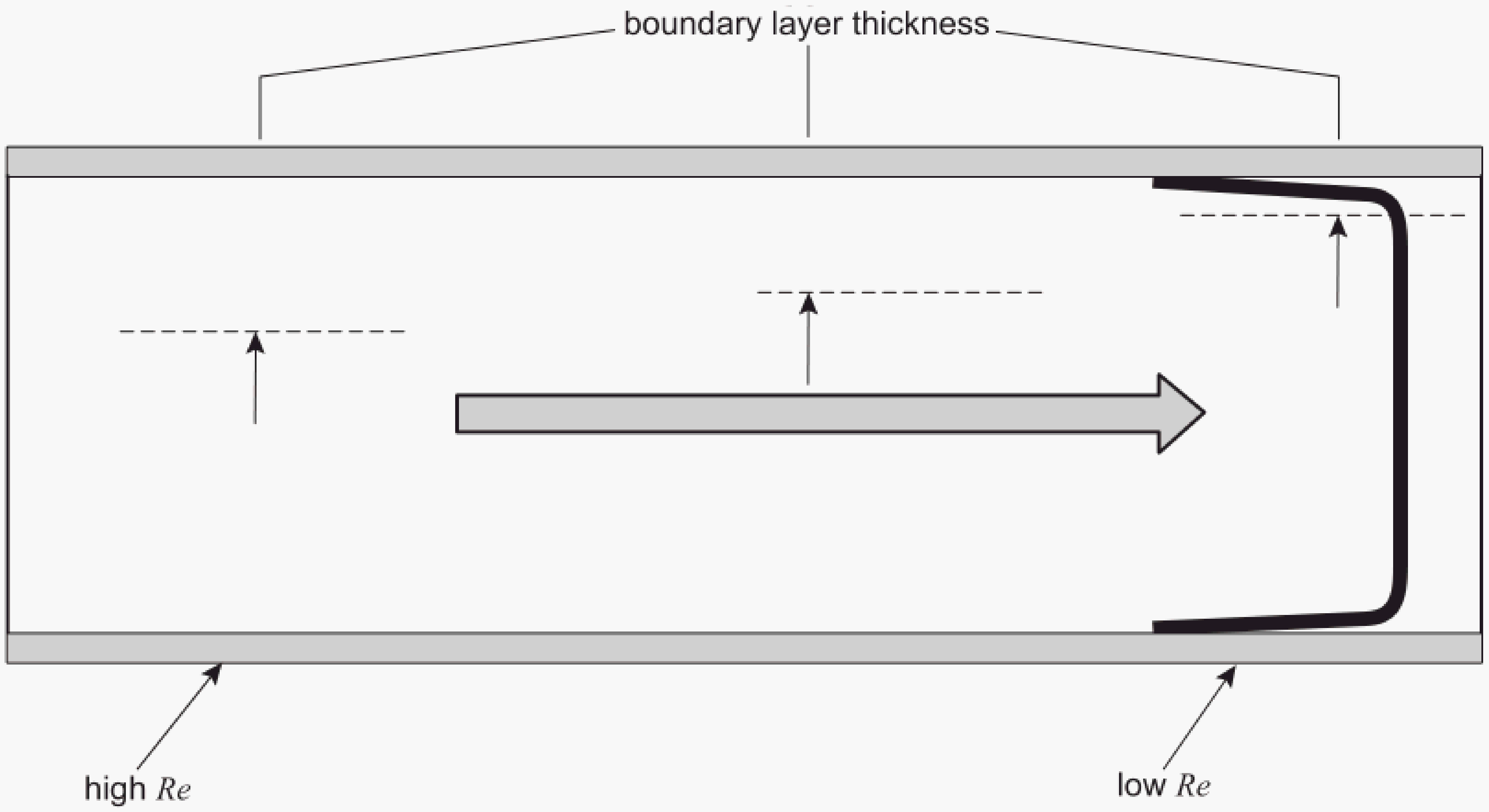


Figure D.2—Increasing Boundary Layer Thickness with Decreasing Reynolds Number

This gradient is sometimes called the boundary layer. In any case, for a given pipe with a given wall roughness, the shape of the fully developed velocity profile is determined by Reynolds Number.

The ultrasonic meter measures differences in upstream and downstream acoustic signal transit times to measure the average fluid velocity along the acoustic paths. This measurement can be done with great accuracy; however, to determine the average fluid velocity across the full cross-sectional area of the meter, it is necessary to make some assumptions concerning the flow profile. Once the average flow velocity has been determined, it is easy for the meter to determine flowrate if the cross-sectional area of the meter is known, or at least, is the same as when the meter was proved. On the other hand, if the effective cross-sectional area of the meter is changed, the accuracy of the meter will be affected. For example, if the viscosity of the fluid changes after a meter has been proved, the thickness of the boundary layer will change. It is easy to see that the effective flow area through the meter is changed and therefore, the accuracy of the meter will have changed. The same can be said if the fluid velocity (flowrate) changes after the meter has been proved. However, the interesting fact is that the thickness of the boundary layer will always be the same whenever the flowrate and viscosity result in the same Reynolds Number as shown in Figure D.3.

Figure D.4 shows the relationship between the meter factor and flowrate on three oils of different viscosity for a 16 in. multi-path transit time ultrasonic flowmeter.

Figure D.5 shows that the same data as in Figure D.4 correlates nicely when plotted against Reynolds Number of the flowstream.

The variation in meter factor can be at least partially explained by variations in the thickness of the boundary layer changing the effective flow area and the inability of the meter to properly extract the true average flowstream velocity from the shape of the flow profile.

If the meter can approximate the Reynolds Number of the flowstream, a linearization or characterization algorithm can be employed that renders the meter relatively insensitive to Reynolds Number changes within a set range of viscosities and flowrates as shown in Figure D.6.

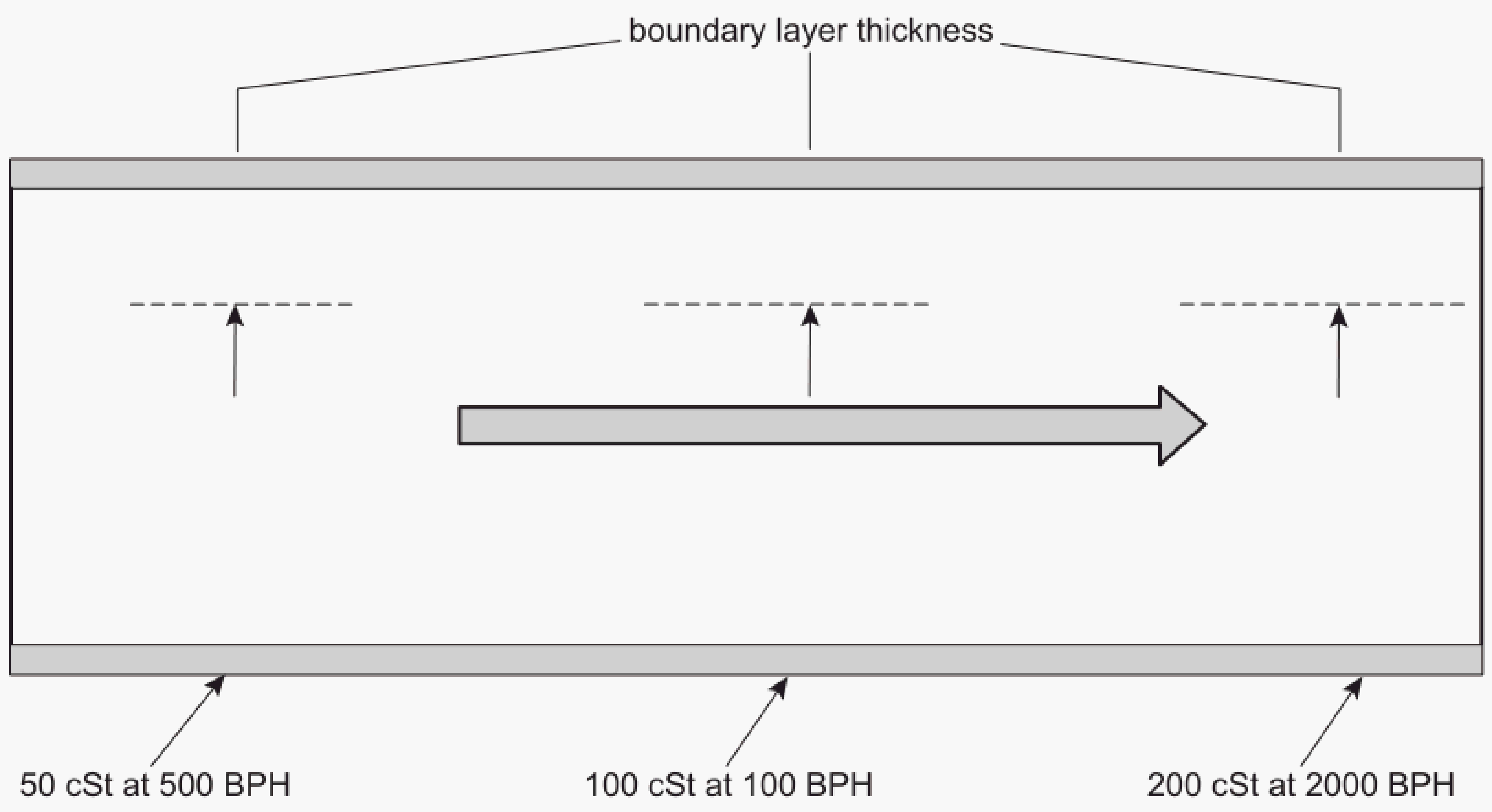


Figure D.3—Constant Boundary Layer Thickness with Constant Reynolds Numbers

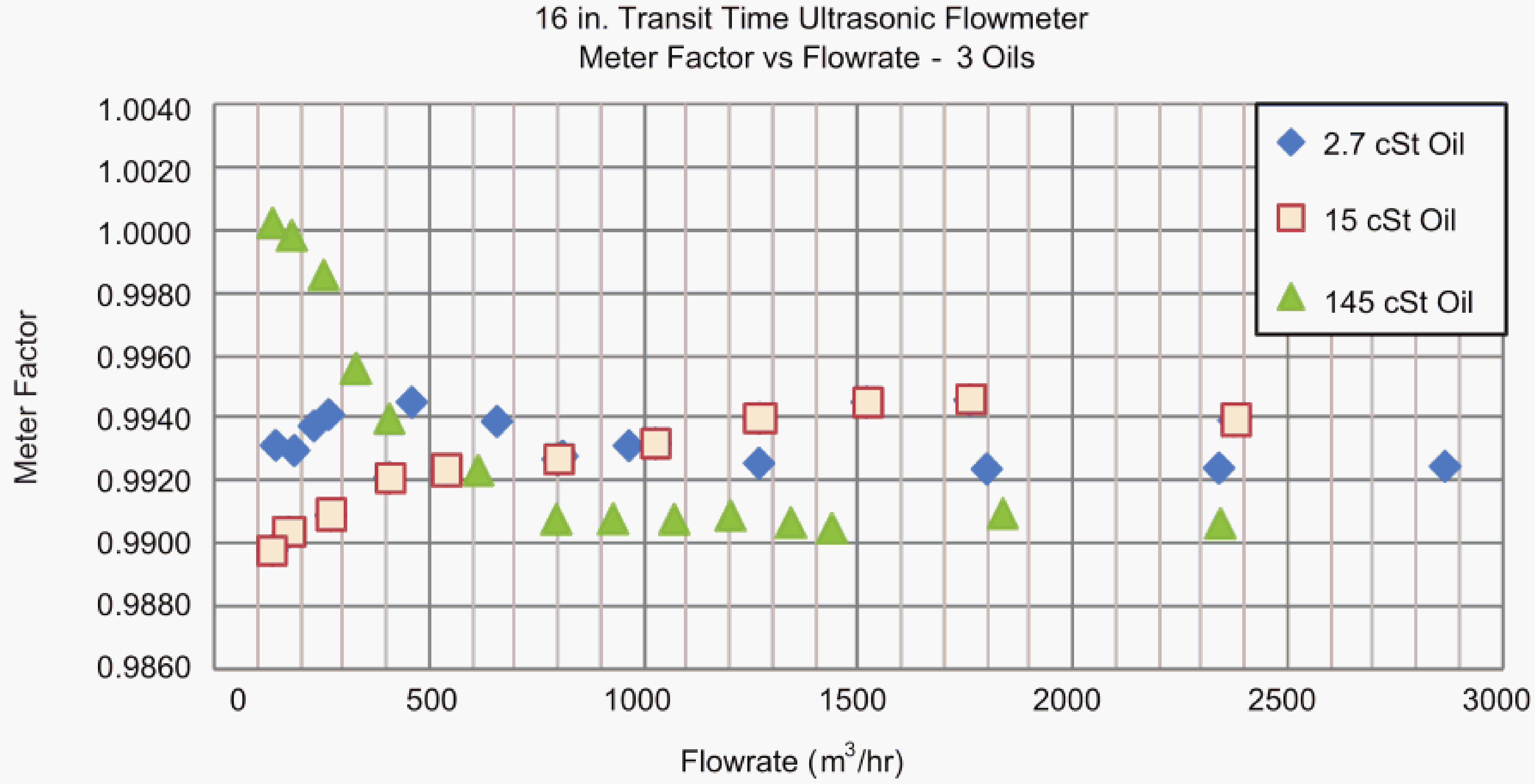


Figure D.4—Meter Factor vs Flowrate – 3 Oils

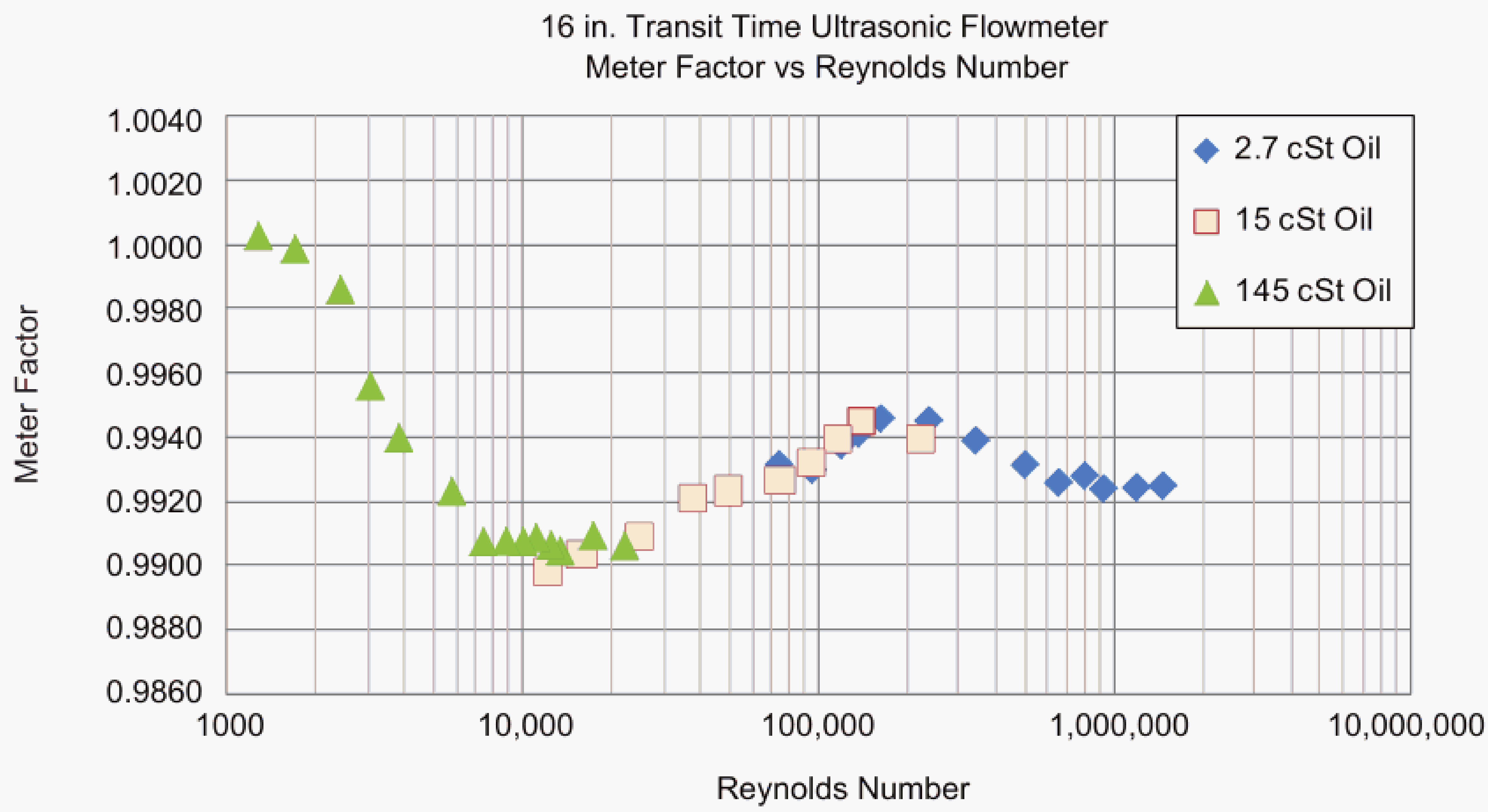


Figure D.5—Meter Factor vs Reynolds Number

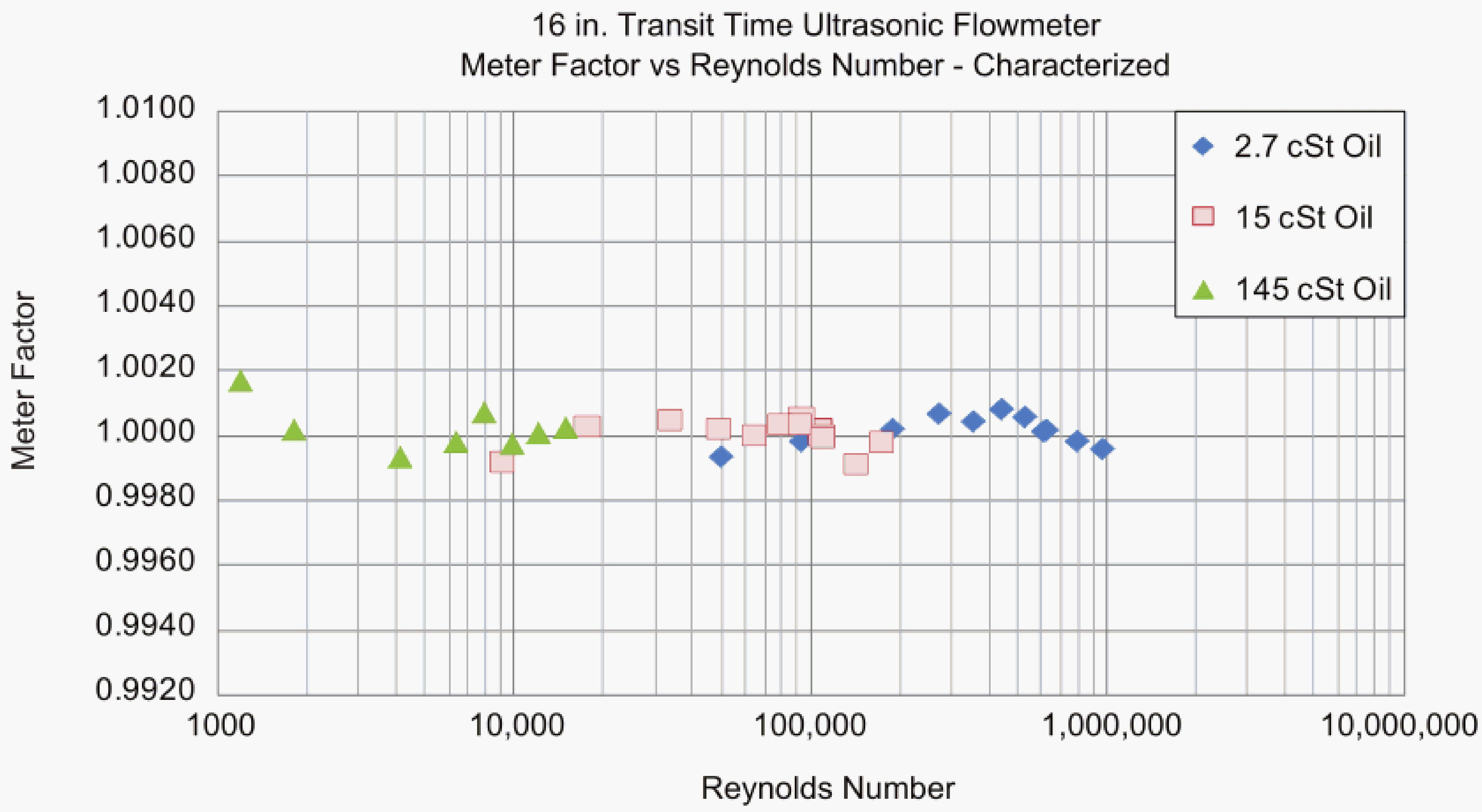


Figure D.6—Meter Factor vs Reynolds Number – Characterized

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