Proving Liquid Ultrasonic Flow Meters for Custody Transfer Measurement

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Introduction

Liquid ultrasonic flow meters (LUFMs) continue to gain popularity in petroleum measurement with the promise of high accuracy and low maintenance. These are favorable features, but because of the high volume and value of petroleum products, buyers and sellers must have a high level of confidence in the accuracy of measurement. This assurance in custody transfer measurement is gained by adherence to the standards, procedures and methods that define the measurement process.

There are two fundamental ways that petroleum products are measured: statically and dynamically. The measured volume determined by either method must be validated at operating conditions and traced to a fundamental standard. In a static system the product is transferred to a tank or similar container. After the transaction is completed the volume can be measured and validated by a suitable method. In a dynamic system PD, turbine or ultrasonic meters provide instantaneous information on the rate and volume of the transfer. As with static methods the measurement results must be validated by a suitable method.

A key difference between a static and dynamic measurement is time. A static measurement is similar to a bank transaction, where the cash draw can be pulled and verified at any time. When a static transaction is complete, there is time to review the measured volume, and if an error is suspected, the volume can be re-measured. With a dynamic system, the measurement must be right the first time; there are no means to re-measure the volume.

The proving system and process are essential in both static and dynamic measurement systems to validate the accuracy of volume measured. There are various worldwide standards and regulations that define the measurement system requirements, but they are fundamentally the same. Each is traceable to a national standard, which in turn, is traceable to the international standard. In dynamic measurement systems this link is the prover volume. There are gravimetric and volumetric methods where the prover volume is traceable the International Bureau of Legal Metrology (BIML). The technical arm of the bureau is OIML (International Organization for Legal Metrology). This is an intergovernmental organization that deals with all aspects of legal metrology. It has 59 member states and 50 corresponding members. In this way all the countries are tied to the same weights and measurement standards, which facilitates world trade.

The various measurement standards either directly or indirectly define the accuracy requirements over a range of operating conditions which include: flow rate, viscosity, temperature, pressure, piping configurations, etc. It is therefore important in the proving process to define both the operating conditions and the accuracy requirements because they are interdependent. A change in operating conditions can affect the meter's accuracy. The greater the change in operating conditions, the more uncertainty is introduced into the measurement. As a general rule, the meter must be proven at operating conditions to validate its accuracy with the highest degree of confidence.

The object of all custody transfer meters is the same: highly accurate measurement, but the procedures to achieve the results may vary with the different meter technologies. This paper will focus on the standards, procedures and methods used to prove ultrasonic meters.

Custody Transfer Requirements

Custody transfer refers to the fiscal measurement used to determine the quantity and financial value of a petroleum product transaction (delivery). The custody transfer requirements can be of two types:

Legal

Defined by Weights & Measures (W&M) in the country or jurisdiction in which the sale is conducted. The various W&M codes and regulations control the wholesale and retail trade requirements to facilitate fair trade. The regulations and accuracy requirements vary widely between countries and commodities, but they all have one common characteristic – traceability. There is always a procedure that defines the validation process where the duty meter is compared to a standard that is traceable to the legal metrology agency of the respective region. The meters for wholesale and retail trade are normally smaller (4" and under) to handle volume flow rates of under 2,800 l/m (750 gpm). These applications are outside the range of current liquid ultrasonic meters and therefore will not be addressed in this paper.

Contract

A contract is a written agreement between buyers and sellers that defines the measurement requirements. These are large-volume sales between operating companies where refined products and crude oils are transported by marine, pipeline or rail. Since even a small error in measurement can amount to a large financial difference, custody transfer measurement must be at the highest level of accuracy possible. Because of the critical nature of these measurements, petroleum companies around the world have developed and adopted standards to meet the industry's needs.

A typical contract may define a specific measurement standard such as the American Petroleum Industry

(API) Petroleum Measurement Standards or an OIML standard that is tied to the International Standards Organization (ISO). These standards include all of the equipment, required and detail the process to achieve an acceptable level of measurement.

Specifying a standard in a contract eliminates the need to enumerate many details concerning the equipment and measurement process that are common industry practice. For example, API Standards are based on "Best Practice.." They define the proper application parameters of a specific flow meter from field experience. OIML standards are "performance based." They set quantitative conditions that any custody transfer meter must meet. To gain approval a specific size and type of meter must be tested over the operating range by a notified body (qualified testing agency) that issues a "pattern test report." The "pattern test report" is then submitted to the respective weights and measures authority as part of the application for approval.

Even though the standards may appear to vary widely, they have two fundamental points in common:

1. They all strive to maintain a minimum measurement error for a specific application and
2. They require traceability to national/international metrology standards by proving the meter.

In terms of accuracy, which is expressed as uncertainty, a good API system would typically have a +/- 0.1% extended uncertainty. OIML requires a minimum system uncertainty of +/- 0.3% over a wide operating range. For large volume transfers, more precise measurement is required, so the systems are proven over a more limited range of operating conditions, typically achieving a +/- 0.1% extended uncertainty – the same as a system using API Standards.

Measurement Definitions

The terminology associated with measurement can be confusing, but is important in understanding the measurement process. Two good sources for measurement terminology are:

API *Manual of Petroleum Measurement Standards* Chapter 1 – "Vocabulary" and Chapter 13 – "Statistical Aspects of Measuring and Sampling"

VIM *"International Vocabulary of Basic and General Terms in Metrology,"* commonly known as VIM, which is accepted by the international community of legal metrology

Included below is a summary of the key terminology used in evaluating a meter's performance. Definitions were selected from both sources. As expected the terminology is similar because accurate measurement is essentially the same worldwide.

Accuracy [API 1.0]: the ability of the measuring instrument to indicate values closely approximating the true value of the quantity measured.

Accuracy of Measurement [VIM 3.5]: closeness of the agreement between the result of a measurement and the value of the measurand.

Measurand [API 1.0] is a physical quantity that has been or is to be measured.

Repeatability (of results of measurements) [VIM 3.6]: closeness of the agreement between the results of successive measurements of the same measurand carried out under the same conditions of measurement which include the same: measurement procedure, observer, measuring instrument, conditions and location over a short period of time.

> **API [1.0] adds** "…the ability of a meter and prover system to repeat its registered volume during a series of consecutive proving runs under constant operating conditions."

Reproducibility (of results of measurements) [VIM 3.7]: closeness of the agreement between the results of measurements of the same measurand carried out under changed conditions of measurement. A valid statement of reproducibility requires specification of the conditions changed. The changed conditions may include: principle of measurement, method of measurement, observer, measuring instrument, reference standard, location, conditions of use and time. Results here are usually understood to be corrected results.

> **API [1.0] adds** "…the ability of a meter and prover system to reproduce results over a long period of time in service where the range of pressure temperature, flow rate, and physical properties of the metered liquid is negligibly small."

Linearity of a Meter [API 1.0]: the ideal accuracy curve of volume meters is a straight line denoting a constant meter factor. Meter linearity is expressed as the total range of deviation of the accuracy curve from a straight line between the minimum and maximum recommended flow rates.

Bias [API 13] is any influence on a result that produces an incorrect approximation of the true value of the variable being measured. **Bias is the result of systemic error.**

Error (of measurement) [VIM 3.10] is the result of a measurement minus the value of the measurand. Since the value of the measurand cannot be determined, in practice a conventional value is used.

Types of Error [API 13 edited]: the difference between the measured quantity and the true value of the quantity includes all the errors associated with the measurement process – the person taking the measurement, the process, the instruments and changes in conditions during the period of measurement. In evaluating a system there are three (3) types of errors:

> **Spurious Error [API]** is a gross mistake or blunder that must be identified and eliminated. There are statistical methods for testing for outliners (e.g., Dixon Outline Test) but data should not be discarded unless there are sound reasons for its elimination.

Random Error [API] is a variation at constant conditions, normally evenly distributed about a mean, which can be statistically analyzed and the uncertainty defined within a given confidence limit.

Random Error [VIM 3.13]: result of a measurement minus the mean that would result from an infinite number of measurements of the same measurand carried out under repeatability conditions. Because only a finite number of measurements can be made, it is possible to determine only an estimate of random error.

Systemic Error [API] is one that remains constant as a positive or negative bias resulting in over or under estimating the true value of the measurement. In many liquid measurement applications, systemic error may make a larger contribution to the overall uncertainty than random error. There are two general classes of systemic error:

Constant Systemic Error is a bias that is particular to an installation and operating conditions. These errors include hydraulic and zero calibration effects.

Variable Systemic Error is a bias that varies with time and includes bearing wear or changes in meter tolerances.

Systematic Error [VIM 3.14]: mean that would result from an infinite number of measurements of the same measurand carried out under repeatability conditions minus the value of the measurand.

Uncertainty of a Measurement [API 13]: the true value of a measurement cannot be determined, but a valid estimator can be obtained by the statistical analysis. The range or interval within which the true value can be expected to lie is the uncertainty range.

Confidence Limit [API 13 edited] It is normally impossible to absolutely set a range of uncertainty. It is more practical to indicate a degree of confidence on this range. This degree of confidence indicates the probability that the uncertainty range contains the "true value." The most common practice is to use a 95% confidence level. This level implies that there is a 95% probability (19 chances in 20) that the "true value" lies within the stated range of uncertainty. The 95% confidence level is recommended for all commercial applications in petroleum measurement. It should also be noted that this is the same confidence level used by legal metrology worldwide.

Uncertainty Analysis: encompasses the statistical analysis of the data derived from a measurement process to determine uncertainty range and confidence limits. It is the highly- mathematical and rigorous process defined in *The Guide to the Expression of Uncertainty in Measurement* or GUM, as it is commonly called. GUM is the result of ISO/TAG/WG 3 and printed in 1995 by ISO; the terminology is defined by VIM. It was fully supported by OIML and BIPM all worldwide legal metrology. In general the analytical method for calculating uncertainty and confidence limit of 95% is fully agreed upon throughout the world.

It is the uncertainty limits that are set by Weights & Measures that are used in the respective countries for the purpose of legal trade. For custody transfer transactions these limits are set by contract. Most times the uncertainty is not precisely stated but based on precedence. An expected level of accuracy has been established over many transactions based on a specific measurement practice. In the US and many other parts of the world, the best measurement practice for pipeline or marine transfers of larger petroleum volumes is based on proving the custody transfer meter in-situ with a displacement-type prover. Typically a custody meter is proven at the start of a batch once the maximum transfer flow rate is established. Since the product is not changing and the variation in flow rate is limited (e.g., +/- 10%), the measurement is at optimum accuracy if the measurement process is sound.

For the purpose of this paper:

Total Uncertainty =
Random Uncertainty + System Uncertainty

By viewing uncertainty in this form, it is easier to understand the measurement process and identify the potential factors that can affect uncertainty. There are a number of variables that can modify the measurement, but we need only be concerned with the key factors which include installation conditions, flow rate, viscosity and temperature for most petroleum products, as well as pressure for lighter products like LPG's. It also should be noted from a review of the definitions that random errors are evenly distributed and will cancel out with a large enough sample. Systemic errors, on the other hand, "remain constant as a positive or negative bias resulting in over or under-estimating the true value of the measurement." Since systemic error or measurement bias is a business risk, identifying and reducing these errors is essential. Proving has always been, and remains, fundamental to custody transfer measurement because it is the only sure method to determine and correct systemic errors.

Unique Problems in Proving Liquid Ultrasonic Meters

Proving, as described, is highly important to the custody transfer measurement and is defined in detail in the respective measurement standards. These standards, especially API "Best Practice" standards, were developed around the available technology. Positive displacement (PD) meters were the only custody transfer meters until the early seventies when API 5.3 *"Measurement of Liquid Hydrocarbons by Turbine Meters"* was issued. Coriolis meters were introduced for petroleum service in the early nineties, but API 5.6 *"Measurement of Liquid Hydrocarbons by Coriolis Meters"* was not issued until 2002. API 5.8 *"Measurement of Liquid Hydrocarbons by Ultrasonic Flowmeters Using Transit Time Technology"* was issued in 2005.

Each of these meter types use fundamentally different technologies to determine the custody transfer measurement. The measurement technology can dictate the application and proving technology. Since the PD and turbine meters have been used for custody transfer measurement over a long period, the proving technology and procedures have been developed around these technologies.

There is a fundamental difference between PD and turbine Meter technology and Coriolis and ultrasonic meter technology that affects proving. The PD and turbine meters produce a discrete volume output for every volume unit measured. For example, a PD meter with electronic output or a turbine meter can produce 1,000 pulses / barrel. Therefore, each time a barrel passes through the measuring chamber a 1,000 pulses will be transmitted. Coriolis and ultrasonic meters use a sampling technique. They sample the flow for a period of time, typically 50 to 500 milliseconds, and then the microprocessor transmits the correct number of pulses for the volume that passed through the meter. The measurement by this method is accurate, but the microprocessor-based flowmeters have two unique problems in regard to proving:

1. **Sample Time** required to achieve an accurate measurement and
2. **Time Delay** in the pulse per unit volume output. There is a further difference between Coriolis and ultrasonic meter in the sampling process; this paper, however, only focuses on the issues affecting ultrasonic meters.

Sample Time

Proving LUFMs can be difficult because of their unique measurement method. A fluid flow stream is a complex flow field with numerous eddies, non-axial components and changing flow profiles. Unlike PD and turbine flowmeters which integrate the flow field by mechanical convergence, ultrasonic meters measure all the numerous eddies and non-axial velocity components in a turbulent flow field. To provide an accurate measurement, the ultrasonic meter must take a number of readings (or snapshots) of the fluid velocity at multiple locations along the product's flow path. The time it takes to acquire a sufficient number of samples for an accurate measurement depends on the flow regime and meter processing time, but, in general, the longer the sample time the better the measurement. These sample times are in the milliseconds, which don't affect the batch measurement, but become a problem with proving. Proving technology, as indicated, is based on discreet pulses for PD or turbine meters. Ultrasonic meters normally require larger prove volumes for the same flow rates than traditional custody transfer meters. However, with proper provers and sound proving practice, highly accurate measurement can be achieved.

Time Delay

Because of the sampling method used in ultrasonic meters, the output at any instant of time will represent a volume that has already passed thought the meter. Under steady flow conditions this lag poses no problem. But if the flow rate is changed, which is typical with displacement provers, this lag can cause poor run repeatability and even bias error in the meter factor. This problem was identified during the development of the *API Ultrasonic Meter Standard 5.8*. In 2003 API formed a task group and funded testing to determine the affect of this pulse delay on meter proving. The group was headed by Kenneth Elliott, who reported the preliminary finding at the 2004 North Sea Measurement Workshop in paper 5.4, *"API's Microprocessor Based Flowmeter Testing Program."* There were a number of interesting findings but the most important results are that:

1. The potential meter factor bias is proportional to the time delay and
2. No accurate factor, based on available data, could be used to correct this systemic error. The practical application of this data is to reduce the meter sample time, and, when possible, minimize flow variations during proving and use larger-volume displacement provers.

Proving Ultrasonic Meters

The problems with proving ultrasonic meters can be resolved by either or both of the two methods:

1. Increase the number of runs. The data scatter for an ultrasonic meter is greater than a conventional meter, therefore it may not repeat in 0.05% in 5 consecutive runs as required for custody transfer measurement. A more general statement would state the repeatability in terms of uncertainty, which is +/- 0.027% at 95% confidence level. This more general statement allows a wider repeatability test tolerance. For example, a repeatability range of 0.12% in 10 consecutive runs or a repeatability of +/- 0.17% in 15 consecutive runs both meet +/- 0.027% at a 95% confidence level. Table 1 is an abridged version of the number of runs at different repeatability ranges to achieve +/- 0.027% uncertainty.

Runs	Repeatability	Uncertainty*
3	0.02%	0.027%
5	0.05%	0.027%
8	0.09%	0.027%
10	0.12%	0.027%
15	0.17%	0.027%
20	0.22%	0.027%

Table 1 – Runs vs. Repeatability

2. Increase the "Prove Volume" to allow a sufficient number of samples. This will also increase the time it takes to complete each prover run, which reduces the time lag to a relatively insignificant uncertainty. As a rule a SVP will not have sufficient "Prove Volume" or "Prove Cycle Time" for proving an ultrasonic meter unless it is oversized and the change in flow rate during the prove is minimal. In the ultrasonic meter standard API proves suggested "Prover Volume" for different size meters. Table 2 shows these suggested prover volumes compared to the typical "Prove Volume" for turbine meters.

Meter Size (Inches)	5 Runs 0.05%		8 Runs 0.09%	10 Runs 0.12%
	Prover Size (Barrels)			
	Turbine Meter	Ultrasonic Meters		
4	5	33	15	10
6	12	73	34	22
8	20	130	60	40
10	24	203	94	62
12	48	293	135	89
16	100	521	241	158

Table 2 – Prover Volume

Proving Systems

Proving systems can be divided into two types:

Direct Proving

Where the custody transfer meter is proven against:

Displacement Provers – Conventional or small volume

Tank Provers – Volumetric or gravimetric. This method is only suitable for PD meters and Coriolis mass meters and will not be included in this paper.

Indirect Proving

Where the custody transfer meter is proven against:

Master Meter Provers – Transfer standard proven, on-site or laboratory-proven

Conventional displacement provers are well-established in this sector of the petroleum measurement industry. Small volume provers (SVP's), because of their size and flow range, have recently gained the industry's interest. Master meters, which were rarely used on large-volume custody transfer systems, are being evaluated because of technical and economic advantages.

Both general proving and proving systems are costly ventures. On large pipelines and marine loading/unloading facilities, the flow line is normally divided into a number of meter runs, each handling a percentage of the flow. Metering systems are designed in this manner to facilitate proving and increase reliability. There is a technical and economic limit on the size of a prover for a given system. For example, it may be more economical on a 12,000 m^3/h (75,000 bph) measurement system to use four12" flow meters and a 6.5 m^3 (40 bbl) prover than –three 16" meters with a 15 m^3 (95 bbl) prover. Also by adding an additional meter run, the system's reliability can be increased because the full flow can be handled by any of the three meters.

In economic terms, design of custody transfer measurement systems becomes a cost versus risk relationship. Table 3 provides the potential cost of systemic measurement errors at different levels of uncertainty. The table clearly illustrates that the cost of a systemic error on a large system can be a substantial risk. A more subtle implication of this table is that using a number of smaller meters is less risky than using a larger meter.

Proving has always been, and remains, fundamental to custody transfer measurement. Choosing the proper prover and method is critical. Below is a review of each method prover with its advantages and disadvantages.

Displacement Provers

Displacement provers are the fundamental device used to verify the performance of large-volume custody transfer meters (≥4" PD) and all types of turbine meters. There are various methods to calibrate displacement provers but all are traceable to a primary metrology standard recognized by BIML for international trade. Displacement provers can be built into a measurement system or a portable prover can be connected into the system. This allows the meter to be validated at the operating conditions.

Conventional Displacement Provers

These are the most common provers in the petroleum transportation market because of their accuracy and reliability. There are two types of conventional displacement provers – uni-directional (Figure 1) and bi-directional (Figure 2). The displacer, which is either a sphere or piston, is installed in a coated pipe of a specific length. The difference between a uni-directional and bi-directional prover is how the displacer is launched and retrieved. The pipe is also fitted with detector switches at two or more points in the pipe. When activated by the displacer, the detector switches define a precise volume which is known as the "prove volume." There are API and other standards that define methods to calibrate this "prove volume" to a high degree of accuracy which is traceable to a national/international metrology standard. When a conventional displacement prover is connected in series with a meter, the displacer is launched and travels at the same speed as the liquid flowing in the pipe.

The switches control the high-speed pulse stream transmitted by the meter. The first detector switch gates an electronic prover counter "on" to collect meter pulses and the second detector switch gates the electronic prover counter "off." The total number of pulses on the electronic prover counter represents the volume recorded by the meter. The indicated meter volume is then compared to precise volume between the prover detector switches. It is possible to calibrate the "Prover Volume" to an expanded uncertainty of +/- 0.02%.

Systemic Uncertainty (+/- U_s)	Daily Value (US $)			Annual Value (US $ Millions)		
	Barrels per Hour					
	10,000	50,000	100,000	10,000	50,000	100,000
0.1%	$11,520	$57,600	$111,200	$4	$21	$42
0.2%	$23,040	$115,200	$230,400	$8	$42	$84
0.3%	$34,560	$172,800	$345,600	$13	$63	$126
0.4%	$46,080	$230,400	$460,800	$17	$84	$168
0.5%	$57,600	$288,000	$576,000	$21	$105	$210

Table 3 – Systemic Uncertainty Risk[1]

1 Based on crude oil at US $60/bbl and 80% duty cycle.

To achieve the required level of accuracy for a custody transfer measurement, the meter must generate at least 10,000 meter pulses between the detector switches. The 10,000 pulse minimum is required because there can be +/- 1 pulse uncertainty at either detector switch, so the resolution is +/- 2 pulses / 10,000 pulses or +/- 0.02%. A uni-directional-type prover normally collects a minimum of 10,000 pulses per proving run. The proving run for a bi-directional prover is both the forward and reverse directions, so a minimum of 20,000 pulses are collected.

Advantages of Conventional Displacement Provers

Ultrasonic meters can be successfully proven with the properly-sized ball-type displacement prover because of the large "prove volume."

The "time delay" of the ultrasonic meter has little effect on ball provers because of the large "prove volume."

It is relatively inexpensive to increase the "prover volume" of ball provers.

If a ball prover is on site with a smaller than required "prover volume," the meter can still be successfully proven by increasing the number of prover runs. Increasing the number of runs compensates for the smaller "prove volume" provided that the required number is not excessive, typically over 20. Normally doubling the number of runs (e.g., 5 runs to 10 runs) with a ball prover is sufficient to achieve a custody transfer uncertainty level of +/- 0.027%.

Ball provers are accepted technology that many users know how to operate and maintain.

Ball provers cost 20% - 50% less than SVP-type displacement provers.

Disadvantages of Conventional Displacement Provers

Size and limited operating range are the key disadvantages. Bi-directional provers have an operating range which is limited to 10:1 (10% to 100% of max flow) for well-lubricated products and 5:1 (20% to 100% of max flow) for dry products. The operating range of uni-directional provers is twice that of bi-directional provers.

Small Volume Type Displacement Provers

Small volume provers (Figure 3) are displacement provers that have a volume between detector switches, which does not permit collecting the 10,000 required meter pulses. To achieve the required level of proving uncertainty, pulse interpolation techniques are used. These techniques divide the initial and final pulse by the use of chronometry. This allows the volume between detector switches to be substantially less than a conventional prover.

Advantages of Small Volume Provers

Size and flow range are the key advantages of SVP's. They have a much smaller footprint than comparable ball provers and have a 100:1 (1% to 100%) flow range.

The small "Prover Volume" in the SVP makes it easier to clean and reduces the contamination between products when used for proving meters with multiple products.

Small volume provers are preferred for offshore platforms because of their size and flow range. The limitation for platforms is flow rate at 17,500 bph for a 12" turbine and 12,500 bph for a 16" PD or 10" ultrasonic meter (2).

They are ideal as portable provers because of size and flow range. The limitation is the weight of the prover. The largest practical size has a 40 gallon "prove volume" which is limited to proving an 8" turbine meter (7,200 bph) or a 10" PD (4,800 bph) or 6" ultrasonic meter (4,000 bph) (2).

SVP's are also becoming popular at pipeline terminals that are being automated, which is the goal of operators. In many cases, though, this excludes ultrasonic meters until the proving problems are resolved.

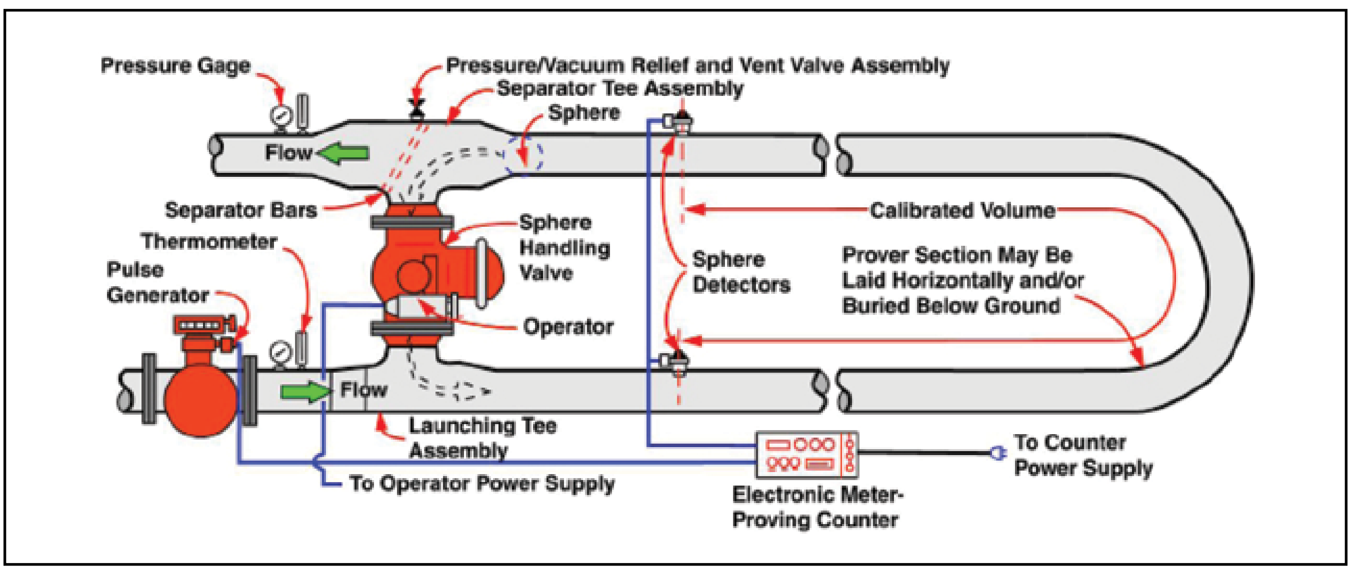

Figure 1 – Uni-directional Prover

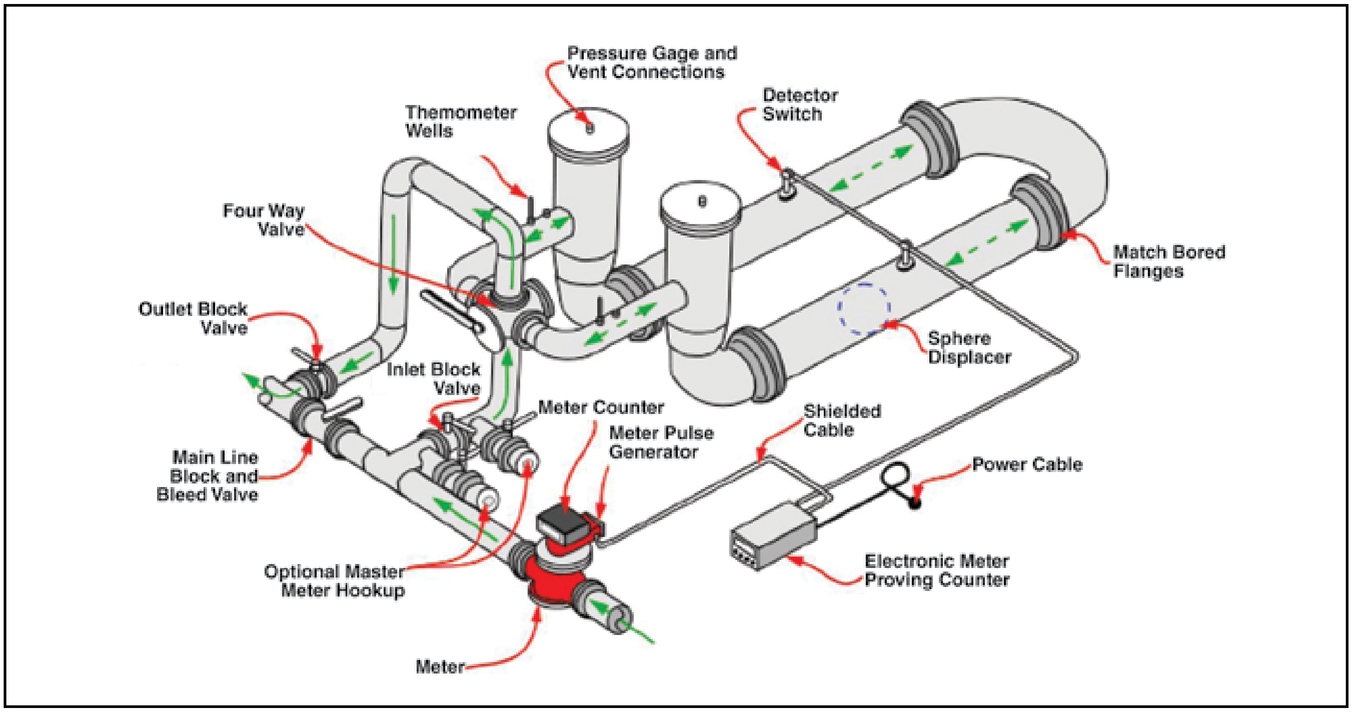

Figure 2 – Bi-directional Prover

Disadvantages of Small Volume Provers

The small "Prove Volume" is problematic for proving ultrasonic meters because the "time delay" and "sample time," as previously explained, are the major disadvantages of SVP's. In most, if not all cases, issues as demonstrated in the API Microprocessor Based Flowmeter Testing Program severely limit the use of SVP's for proving ultrasonic meters. SVP's are also much more complex than pipe provers, and are more susceptible to damage from fluids contaminated by debris, particularly abrasives.

One method that is developed in the "Master Meter Proving" section is Transfer Meter Proving.

Master Meter Proving Systems

A master meter is termed an indirect meter proving method as compared to a displacement prover, which is a direct proving method. API 4.5 *"Master Meters Provers"* only recognizes the use of PD meters or turbine meters as master meters. Currently there is an API working group that is adding Coriolis flow meters and liquid

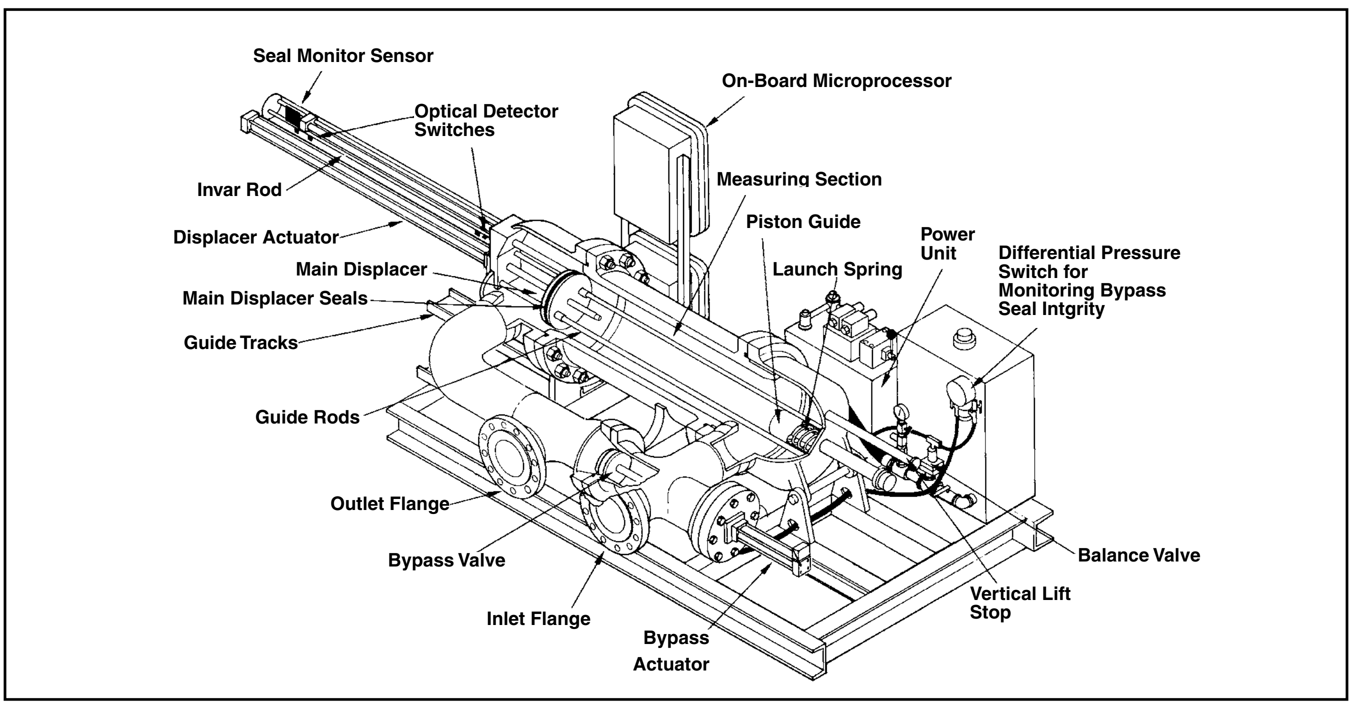

Figure 3 - Small Volume Prover

ultrasonic flow meters to this standard. A revision to the standard is expected for balloting by spring 2010. Until the ballot results are reviewed, it is difficult to predict when the revised standard will be completed, but there isn't any apparent technical reason why these meters would not be added to the standard.

Since the master meter proving is a secondary proving method, it has the highest uncertainty of all meter-proving methods. As previously defined, the total or extended uncertainty of a proving system is the combination of random and systemic uncertainty. The expanded uncertainty for proving a master meter with a SVP can be expressed as:

$$U_T = U_R + \sqrt{U^2_{MM} + U^2_{SVP}}$$

Where:

- U_T – Total uncertainty of a typical prove
- U_R – Random uncertainty, which is the repeatability of the meter runs
- U_S – Systemic uncertainty, which is the combined uncertainty of the master meter and SVP
- U_{MM} – Master meter uncertainty (systematic)
- U_{SVP} – SVP volume uncertainty (systematic)

Systemic error, as defined, is one that remains constant as a positive or negative bias in the measurement. Since it can make a large contribution to the overall uncertainty (U_T) it is imperative to determine and correct for this bias by proving the meter. The wider the variation in installation and operating conditions, the greater the potential systemic error and associated uncertainty.

Two separate sequences of events are necessary in master meter proving. First, the master meter must be calibrated using a prover that is traceable to a national/international standard. Once the master meter is calibrated, it can then be used to calibrate the field-operating meter.

Factors That Contribute to Uncertainty in Master Meter Proving

To best understand the uncertainty in master meter proving, it is helpful to distinguish between the Constant Systemic Errors introduced by installation and operating conditions and Variable Systemic Errors that vary with time, which include bearing wear, changes in meter tolerances, strainers and piping conditions. In general, ultrasonic meters are more sensitive to installation and operating conditions than PD and turbine meters, but less sensitive to the variable system errors because there are no moving parts.

Constant Systemic Error Contributions

Installation Effects – refer to anything in the measurement system set-up that can cause a systemic change in the meter factor. Certain metering technologies like PD and Coriolis meters are only slightly affected by installation conditions whereas velocity meters such as turbine and ultrasonic meters can be highly affected. Multipath ultrasonic meters may have algorithms that detect and compensate for these effects, but on an individual meter basis, it is difficult to determine how effective the algorithms are in handling these anomalies.

Currently with transfer proving, the total uncertainty (U_T) of a liquid custody transfer measurement can be made in the range of U_T = +/- 0.1% at a 95% confidence level. This is industry norm for most large volume liquid transactions. If a large systemic installation error (e.g., +/- 0.5%) goes undetected for even a small period of time, the business risk for over or under–delivery will increase.

Operating Effects– The most important operating conditions that affect the accuracy of liquid measurement are: flow range, viscosity range and temperature.

Flow Range is the minimum/maximum flow rate at which a meter/measurement system can operate and maintain the stated accuracy. Custody transfer meters are normally specified to operate over a 10:1 (10% to 100% of maximum flow) flow range with a linearity of +/- 0.15%. This means that if all the operating conditions are held constant and only the flow rate is varied, then the maximum meter factor variation will be +/- 0.15% over the flow range. This variation in meter factor does not include any systemic error due to installation conditions or changes in the other operating conditions. The accuracy of the measurement can be improved by reducing the flow range or establishing a separate meter factor for each flow rate. With today's flow computers a number of meter factors versus flow rates can be programmed, and automatically linearize the meter factor. At a given flow rate the measurement uncertainty (U_R) becomes the repeatability of the meter which must be ≤ +/- 0.027% for custody transfer measurement.

Viscosity Range of petroleum products can vary from less than 0.1 cP for LPG's to over 1,000 cP for heavy crude oils (see Table 4). All meters are sensitive to viscosity but each metering technology is affected differently. Because of the slippage principle, PD meters are affected on low viscosity products (< 2 cP) whereas turbine and ultrasonic meters are sensitive to high viscosity products. Multi-path ultrasonic meters may have algorithms that compensate for viscosity, but on high viscosity crude oils the other factors such as particles and entrained gas may also affect the measurement accuracy.

Temperature affects the measurement in several ways:

1. The viscosity can change as illustrated in Table 4; 2
2. Changes in liquid volume as defined by the volumetric coefficient of expansion;
3. Changes in meter tolerances that affect the MF and
4. A change in the prover volume.

There are correction factors for the volumetric expansion of liquids and prover volumes, but master meter factors must be established for specific temperatures within the operating range. Since the repeatability of a meter during proving is based on a gross volume (non-temperature compensated volume), it is highly important to maintain a minimum temperature difference between the meter being proved and the prover. For example, a 2° F change

Product	API Gravity	Viscosity in cP		
		60°F (15°C)	100°F (38°C)	150°F (66°C)
Propane - LPG	145	0.12	0.09	0.07
Gasoline	56	0.63	0.49	0.38
Kerosene	40	2.2	1.7	0.9
Light Crude	48	2.7	1.7	1.1
Light Crude	32	21	9	5
Medium Crude	25	1,442	243	93
Heavy Crude	16	3,440*	547	230*
Heavy Crude	10	5,100*	1,294	520*

** Estimated*

Table 4 – Viscosity of Selective Products

in temperature between the meter under test and the prover will impact meter factor and custody volume by 0.1% across the entire product range.

Variable Systemic Error Contributions

The variable systemic errors are associated with the stability of the master meter over time. Wear in a mechanical meter can cause a shift in the factor due to bearing wear or changes in critical tolerances. There can also be waxing or other coatings that similarly cause shifts in the calibration factor. Debris caught in the strainer basket and/or on flow conditioning elements can have a significant effect on the master meter's calibration.

The only way to confidently detect and correct for these systematic bias is by periodically reproving the meter and comparing the proving results. This raises the question, how often does the master meter need reproving? Because of the variation in master meters, service conditions and acceptable level of uncertainty (risk), it is impractical to establish a fixed time. The answer to this question can only be gained from careful analysis of the data. API 13.2 provides statistical methods to evaluate and track proving data but a practical approach would be:

- Establish the base line meter factor for the master meter on each test fluid under consideration. This would consist of ideally six runs at different times and conditions over which the master meter will operate.
- Develop a control chart based on the uncertainty tolerance that is acceptable. Typically for custody transfer measurement of U_T = +/- 0.1% the current master meter factor (MMF) should be within 0.02% of the last meter factor and the baseline meter factor. The maximum allowance from the baseline should be 0.04%.
- The time between provings can be increased based on the master meter factor's stability. Typically a good master meter should remain within the stated tolerances for a least 1 year, or 200 hours of service. The precise criteria, though, is based on the system and the agreement of the parties affected by the measurement.

Transfer (Master Meter) Proving

With "Transfer Proving" the master meter is proven on site, which eliminates systemic errors due to installation effects. It also provides the ability to prove over the complete operating range, and if the conditions change or if measurement is challenged, the master meter can be easily re-proven.

There is an added uncertainty of the master meter to the total uncertainty budget, but it can be precisely calculated. In practice, the uncertainty added by a master meter should be far less than the bias caused by a change in conditions.

Currently this method is used to prove terminal load rack meters at large terminals. Normally a PD master meter is installed in series with one of the line meters and validated using a volumetric can prover. The other delivery meters on the same product are then calibrated against the master meter with the product being pumped directly into the tank truck compartment. This is far more efficient than proving each meter with a volumetric tank and pumping the product back to storage.

The same method, if applied to proving ultrasonic meters, would eliminate both the "time delay" and "sample time" issues. The master meter, whether it is a PD or turbine meter, can be proven with a conventional or small volume prover (SVP) and then used to calibrate the ultrasonic meter. Since the master meter is not limited by "prove volume" an adequate volume can be run through the master meter to eliminate both the "time delay" and "sample time" issues.

Laboratory Calibrated Master Meter

Laboratory calibrated master meters have the highest level of uncertainty because of the bias introduced by installation and operating conditions. All meters have some sensitivity to installation and operating conditions and the resulting bias must be quantified for custody transfer measurement. The difficulty of determining this bias depends on the total uncertainty (U_T) required (level of acceptable risk) and the degree of variation in the installation and operating conditions. Obviously a lower level of uncertainty (e.g., U_T = +/- 0.1%) with a wide variation in operating conditions is significantly more difficult to determine than a higher level of uncertainty (e.g., U_T = +/- 0.5%) over a limited flow range, with one product at a stable operating temperature. In either case, the analytical methods used to determine uncertainty analysis are dependent on test data for the specific type of meter and operating conditions. Specific data is required for each type of meter, brand, meter model and size to develop an analytical model. The calibration factors developed by the model should then be validated in the field by proving the master meter in-situ over the operating conditions. As more data is gathered the confidence in the measurement will increase and the factors affecting the measurement can be identified and improved to reduce the total uncertainty (U_T).

Laboratory-proven meters are not normally used for large volume custody transfers because of the limited knowledge of the installation and operating effects. But even today the economical advantages may far outweigh the uncertainty risk. In the long run, improving the diagnostic capabilities of master meters and defining the installation conditions will lower the uncertainty to an acceptable level.

Choosing a Master Meter for an Ultrasonic Application

The use of master meters for large custody transfer applications (6" and larger meter, over 4,000 bph) is not common practice because of the increased risk with large volume transfers. Normally the meters are directly proven with a displacement prover, either a Conventional Displacement Prover or more recently a SVP. The latter provers are becoming more popular because of their smaller space requirement and recent improvements in reliability. The use of SVP to prove ultrasonic meters is difficult because of the time delay and sampling requirements. On-site or portable conventional provers may be too small for the respective ultrasonic meter. Master meters for these applications may offer a technically sound alternative.

For the purpose of this paper it will be assumed that Coriolis Flow Meters (CFM's) and Liquid Ultrasonic Flow Meters will be added to API Standard 4.5. – Master Meter Provers. Since CFM's are applied at low flow rates, they have limited application as a master meter for ultrasonic applications. PD meters, conventional turbine meters, helical turbine meters and ultrasonic meters are possible selections.

Traditionally PD meters were applied for high viscosity products and turbine meters for low viscosity products. This rule-of-thumb has a sound technical foundation. The PD direct measurement principal is based on slippage theory. That is, the volume through-put is segmented and directly measured in the measurement chamber, except for a small amount that slips though the clearances. This slippage is a constant for a given product, flow rate and temperature. By proving the meter, the bias due to slippage can be identified and compensated with a calibration factor. As the product viscosity increases, the slippage decreases. At a given viscosity (about 10 cP for a 10" PD meter) the slip is essentially "zero." In addition, the meter factor remains constant for all higher viscosity products and over a wide flow range.

PD meters directly measure volumetric flow and as such are not highly affected by installation conditions. Coriolis meters are likewise not affected by installation conditions as long as a stable "zero" can be established and maintained. Turbine and ultrasonic meters measure velocity and are therefore affected by the dynamic flow conditions established by the installation conditions.

Turbine meters are far more sensitive to viscosity. A conventional multi-bladed turbine meter is normally applied to liquid viscosity of 2 times the meter's size in inches and a helical turbine meter to 10 times the meter's size in inches. In either case, as the viscosity increases the minimum flow rate must be increased, limiting the meter's overall flow range.

Ultrasonic meters, like turbine meters, are sensitive to viscosity effects. They are not independent of these effects as some suppliers claim, but they can be designed to compensate for viscosity profile effects.

Conclusion

When properly proven, liquid ultrasonic flow meters can provide Custody Transfer accuracy. Conventional uni-directional and bi-directional provers provide the best direct proving method for Custody Transfer meters. A direct method has the least uncertainty because it eliminates the added uncertainty of a master meter.

It is difficult to directly prove a liquid ultrasonic meter with a Small Volume Prover because of its small "prove volume." The time lag, with changes in flow rate, becomes a significant percentage of the run time per pass and can cause a bias error. The small "prove volume" also limits the number of samples which affects repeatability. A SVP can be used in a Transfer (Master Meter) Proving system. In these applications a PD or turbine would normally be used for the master meter.

Master Meter proving can be used to calibrate a liquid ultrasonic meter but it does add uncertainty to the measurement. The Transfer Master Meter Proving method is preferred, however, because it eliminates the bias caused by installation effects and allows the master meter to be calibrated at operating conditions. The master meter can also be easily re-proven if there is any doubt about the measurement.

The greatest uncertainty is introduced when the Laboratory Proven Master Meter method is used. In this method the systemic bias caused by the installation effects is difficult to estimate. Similar operating conditions are often difficult to simulate in a laboratory, and any differences in operating conditions add to the expanded uncertainty budget. When the operating conditions change, the master meter will need to be re-calibrated at these new conditions.

Liquid ultrasonic meters can be accurately proven by a number of different methods. The best proving method depends on properly assessing the "risk cost" of a measurement error compared to the cost of the measurement system. In most high-volume custody transfer applications the proving system with the least uncertainty and corresponding lowest risk is the best.

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