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FUNDAMENTALS OF LIQUID MEASUREMENT III - DYNAMIC
CLASS 2180

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INTRODUCTION

We've learned when measuring crude oil or any hydrocarbon that liquids expand and contract with increases and decreases in temperature. The liquid volume also decreases when pressure is applied. All these effects are part of the physical properties of liquid petroleum fluids. In addition to the effects of temperature and pressure on the liquid and their indicated volume, the container in which the liquid is measured also changes the volume it contains at different temperature and pressures. These changes must also be accounted for in determining the true volume being transferred. We learned in Fundamentals of Liquid Measurement I how these physical properties effect the measurement of liquid hydrocarbons. The objective of either static measurement or dynamic measurements is to determine the quantity and quality of hydrocarbons transferred. However these measurements are rarely performed at the standard conditions discussed in Fundamentals I, therefore not only must temperature be measured, but also density, sediment and water, vapor pressure, flowing pressure and viscosity must be measured. With these measurements correction factors such as Volume Correction Factors (VCF) can be determined to allow volumes determined at operating conditions to be expressed at standard reference conditions.

The means of measuring hydrocarbon liquids fall into one of two methods:

Static measurement

Dynamic measurement

Static measurement is performed when the hydrocarbon liquid is at rest and contained within a container such as a tank, hence it is commonly referred to as Tank Gauging. On the other hand when hydrocarbon liquids are measured while in motion, this is referred to as dynamic measurement or Metering.

Another why to think of the difference in measurement techniques is to think of static measurement as measuring the volume in a container at a point in time and dynamic measurement as measuring the volume in a container over time.

This paper will examine the various types of meters, their accessories and the devices to verify the meter's performance.

CUSTODY TRANSFER

In simple terms, "custody transfer" is the transfer of ownership or responsibility for a liquid hydrocarbon from one party to another. Since ownership is being transferred, either immediately or eventually, it is essential that accurate accounting be used so that all parties involved in the transaction receive their fair measure. With the prices for hydrocarbons these days it is obvious how important accurate accounting—hence, accurate measurement becomes. The words “custody transfer” have become synonymous with accurate measurement.

However the terms “measurement (volume) accuracy” and “meter accuracy” are not the same. Measurement accuracy as applied to volumes is the absolute accuracy of the volume measured, whereas “meter accuracy” is the accuracy of the meter relative to a reference standard, such as a prover.

The term’s repeatability and linearity are commonly used to define meter accuracy. Repeatability is the variation in the meter’s performance under constant operating conditions, i.e. constant flow rate, temperature, density, etc. Where-as linearity is the variation in the meter’s performance over a range of flow, commonly referred to as the turndown-ratio.

Therefore measurement accuracy of volumes is influenced by the following factors:

- Meter repeatability
- Liquid density corrections due to varying temperature and pressure
- Meter calibration or proving, including procedures
- Variations in operating conditions and their effect on a meters performance
- Calibration of prover, i.e. water draws.

METER SELECTION

In general two types of meters have been used in custody transfer measurement of liquid hydrocarbons. They are positive displacement (PD) meters and turbine meters. Recently another type of meter, the Coriolis force flow meter is finding use in custody transfer measurement of liquid hydrocarbons. A fourth type of meter, the ultrasonic transit-time meter is also now being considered for custody transfer measurement operations. In 2005 the draft standard was upgraded to a full standard for ultrasonic meters. The selection of a specific meter type depends on its application. In some applications a specific type is preferred, while in others any meter type would perform satisfactorily.

All meter installations must meet certain fundamental requirements. These include accurate proving facilities; adequate protective devices, such as strainers, relief valves, and air or vapor eliminators; and dependable pressure and flow controls. Additionally, accurate instrumentation for measuring the physical properties of the flowing fluid, such as temperature, density, etc is needed. A further fundamental is that physical conditions during normal metering operations and proving of the meter must be identical. The following should be considered when selecting a meter and its auxiliary equipment.

- Flow range and whether flow is intermittent or continuous
- Pressure—maximum operating pressure and maximum permissible differential pressure
- Type of liquid and its characteristics
- Temperature range and accuracy of temperature compensation
- Type of volume registration device
- Accuracy required

- Type and method of proving required
- Applicability of auxiliary meter registration equipment
- Maintenance requirements
- Foreign matter in fluid streams
- Installation space available

TYPES OF METERS

Positive Displacement (PD) Meter—a positive displacement meter is a device installed in a piping system in which flowing liquid is constantly and mechanically isolated into segments of known volumes. These segments of liquid are counted as they are displaced, and their accumulated total continuously and instantaneously indicated in units of liquid quantity by a meter register, pulse generator or flow computer. The type of mechanism employed to isolate the liquid segments, i.e. by the nature of their measuring element, generally differentiates positive displacement meters. The terms used to describe the most common types of measuring elements are:

- Nutating disc
- Reciprocating piston
- Sliding-vane type rotary
- Bucket-type rotary
- Lobed rotary
- Helical rotary
- Certain combinations of the above

Positive displacement meters are commonly used for all types of liquid measurement, especially for viscous liquids such as crude oil. However, their use in light hydrocarbon services such as propane, butane, etc., may result in high maintenance due to the lack of lubrication. They are frequently used in product services such as loading rack applications even though a turbine meter may be more desirable for the liquid being measured. The reasons being that loading racks are intermittent service…a service better suited to PD meters.

Positive displacement meters are generally considered to have a 5/1 turndown, i.e., maximum flow to minimum flow. They are typically selected to limit their operating range to between 40 percent and 80 percent of their stated flow range due to inaccuracies at the low end and rapid meter wear at the high end. However, if proved when operating above 80 percent and below 40 percent and that proving meets the repeatability requirements, then they can be used successfully.

Positive displacement meters have an advantage over turbine meters in that they are not affected by viscosity and they require no flow conditioning, i.e., straightening vanes upstream of the meter. They are subject to wear which means that erosive fluid applications require special care in filtering and frequent meter proving to maintain their accuracy. Positive displacement meters are used predominantly on LACT (Lease Automatic Custody Transfer) units and on crude oil ACT (Automatic Custody Transfer) units.

Turbine Meter—the liquid turbine meter is an inferential type of volumetric measurement device installed directly in the pipe of a flowing system. The turbine meter housing has an internal rotor that rotates with respect to the linear velocity of the fluid passing through the cross-sectional area of the meter housing. As the fluid passes through the meter housing, the angular velocity (rpm) imparted to the turbine rotor is proportional to the linear velocity of the flowing fluid. The volumetric flow rate can then be determined by the rotor speed (rpm).

The volumetric flow rate (Q) is assumed to be proportional to this measured flow velocity (V) by assuming a constant flow area (A).

$$Q = (V)\,(A)$$
$$(ft^3/sec) = (ft/sec)\,(ft^2)$$

The accuracy of the flow measurement can be affected if the assumption that the flow area remains constant does not. Factors contributing to the changing flow area include:

- Deposits (such as paraffin)
- Boundary layer thickness
- Cavitation
- Debris
- Operating conditions (i.e., temperature, pressure, density, etc)

Additionally the assumption that the rotor velocity is directly proportional to the axial velocity through the turbine meter can be affected by the following:

- Bearing friction
- Viscous friction
- Rotor blade configuration
- Flow conditioning

Turbine meters are used primarily for refined product and light hydrocarbon measurement. Although they reportedly have a 10/1 turndown range, care should be taken to select a meter size to operate within 50 percent to 100 percent of its stated flow range. Large inaccuracies may result when operating below the 50 percent flow level.

Turbine meters are generally used in trash-free flowing applications since any possibility of build-up on the rotor will impede its rpm—hence measuring ability. Early installations of turbine meters suffered high failures due to frequent rotor bearing failures. The use of tungsten carbide bearings has greatly reduced the failures and inaccuracies due to bearing friction.

When using turbine meters in light hydrocarbon liquid mixtures such as ethane-propane, NGL's care should be exercised, in that the linear operating range is raised, and the meter should be selected to operate over the 80 percent to 125 percent range of the stated flow range. The lighter fluid impinging on the rotor blades has less force at lower capacities causing erratic rotation and accompanying inaccuracies.

Turbine meters register volume utilizing a pulse generator called a pick-off coil and a pre-amp. As the blade tip or paramagnetic button passes through the magnetic field generated by the pick-off coil a pulse is generated. This pulse is collected or counted by an electronic register, such as a flow computer. Typically each turbine meter has a K-factor assigned, which is a nominal number of pulses per unit volume. Volume is determined by dividing the accumulated pulses by the K-factor as shown:

$$\text{Volume} = (\text{Pulses}) \div (\text{K-factor})$$

Turbine meters being velocity or inference type devices require flow stream conditioning for their accurate performance. The detailed requirements for flow conditioning can be found in API MPMS Chapter 5, section 3—"Measurement of Liquid Hydrocarbons by Turbine Meters". Typical flow conditioning consists of upstream and downstream straightening sections. The upstream section usually contains a tube bundle, which allows the upstream section to be reduced in length. This tube bundle serves to eliminate any "swirl" in the flow stream before reaching the meter presenting a Symmetrical velocity profile to the turbine rotor.

Coriolis Meter—the liquid Coriolis force flow meter is an inferential type of volumetric measurement device installed directly inline in a flowing system. The coriolis flow meter is a mass meter, which measures mass flow rate directly and infers volume. The coriolis meter is device that by means of the interaction between a flowing fluid and the oscillation of a tube(s), measures mass flow rate. The Coriolis meter consists of a flow sensor and a transmitter.

The flow sensor is a mechanical assembly consisting of:

- Housing: a means for providing environmental protection. It may or may not provide secondary containment.
- Measurement sensor: sensors to monitor oscillations and detect the effect of coriolis forces. These may also be referred to as pickups or pickoffs.
- Support structure: a means for supporting the vibrating conduit.
- Vibrating conduit: oscillating tube(s) or channel through which the fluid to be measured flows.
- Vibration drive system: the means for inducing the oscillation of the vibrating tube.

The transmitter is an electronics assembly, which interprets the phase shift signal from the sensor, converts it to a meaningful mass flow rate (represented in engineering units or a scaled value), and generates a digital or analog signal representing flow rate. Many manufacturers also use it to drive the sensor tubes, determine fluid density and calculate a volumetric flow rate.

As the fluid passes through the flow sensor, inertia forces are generated whenever a particle in a rotating body moves relative to the body in a direction toward or away from the center of rotation.

A particle of mass δm slides with constant velocity v in a tube T that is rotating with angular velocity ω about a fixed point P. the particle acquires two components of acceleration:

a. A radial acceleration a_r (centripetal) equal to $\omega^2 r$ and directed towards P.
b. A transverse acceleration a_t (Coriolis) equal to $2\omega v$ at right angles to a_r and in the direction of ω.

To impart the Coriolis acceleration at to the particle, a force of magnitude $2\omega v\delta m$ is required in the direction of at. This comes from the oscillating tube. The reaction of this force back on the oscillating tube is the Coriolis Force $F_c = 2\omega v\delta m$.

When a fluid of density ρ flows at constant velocity along an oscillating tube, which is rotating, any length Δx of the oscillating tube experiences a transverse Coriolis force of magnitude $\Delta Fc = 2\omega v \rho A \Delta x$, where A is the cross-sectional area of the oscillating tube interior.

The mass flow rate Q_m can be expressed as:

$$Q_m = (dm) / (dt) = \rho AV$$

We then have that

$$\Delta F_c = 2\omega q_m \Delta x$$

The accuracy of the flow measurement can be affected by various factors. Factors contributing to the flow measurement accuracy include:

- Zero stability (Re-zeroing)
- Zero offset
- Fluid Properties
  - Density
  - Viscosity
- Operating Conditions
  - Flow rate variations
  - Fluid temperature
  - Fluid pressure
  - Multiple-phase flow streams (liquids/gas/solids)
  - Flashing and/or cavitation within the flow sensor
  - Coatings or deposits within the flow sensor
  - Erosion of the flow sensor
  - Corrosion of the flow sensor
- Installation conditions
  - Vibration
  - Multiple flow sensor vibration interference (crosstalk)
  - Pulsating flow
  - Mechanical stress – axial, radial and torsional stresses caused by piping installation
  - Swirl or non-uniform velocity profile
  - Electromagnetic and radio frequency interference
  - Voltage regulation

Ultrasonic Meters – the liquid ultrasonic transit time meter is an inferential type of volumetric measurement device installed directly inline in a flowing system. The principles of operation are that a set of acoustic transducers transmit a high frequency acoustic pulse diagonally across the pipe. The transit time method measures the time intervals associated with transmission of this acoustic energy across the pipe in opposing directions. From these time measurements a flow rate can be calculated as shown below:

$$\mathbf{T_u = \quad L_p/(C-V_p)}$$

$$\mathbf{T_d = \quad L_p/(C+V_p)}$$

From these time measurements then volume can be calculated from the following:

$$V = [Lp \times (Tu - Td)] / [2 \times Td \times Tu \times \text{Cos}Ø]$$

where

Td	=	Downstream transit time
Tu	=	Upstream transit time
Lp	=	Path length
C	=	Speed of sound in the fluid
Vp	=	Flow velocity along path length
V	=	Flow velocity along the pipe axis
CosØ	=	angle the acoustic path makes with pipe axis

- Transit Time Measurement—a function of
  - Measuring path length
  - Transit time measurement
  - Fluid velocity
- Volumetric Flow Rate
  - Path velocity be related to the axial fluid velocity
  - Axial fluid velocity (acoustic path) be related to the mean axial velocity for pipe cross section
- Volume = Area (pipe) x Average Fluid Axial Velocity

Ultrasonic meters being velocity or inference type devices require flow stream conditioning for their accurate performance. The detailed requirements for flow conditioning can be found in API MPMS Chapter 5, section 8—“Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters using Transit Time Technology”. Typical flow conditioning consists of upstream and downstream straightening sections. The upstream section usually contains a tube bundle, which allows the upstream section to be reduced in length. This tube bundle serves to eliminate any “swirl” in the flow stream before reaching the meter presenting a Symmetrical velocity profile to the turbine rotor.

SOME ULTRASONIC FLOWMETERS MAY PRODUCE A NON-UNIFORM PULSE OUTPUT, WHICH CAN EXHIBIT A WIDE SPAN OF REPEATABILITY WHEN PROVED.

METER ACCESSORIES

Custody transfer meter installations require proper accessories irrespective of meter type. Common accessories include strainers or filters, pressure gages, thermometers and thermowells, registering devices, temperature and pressure transmitters, pulse generating devices, pulsation dampening equipment, prover connections, air eliminators, pressure and flow controllers, and straightening vanes. A discussion of some of these devices is as follows:

1. Strainers—both PD and Turbine meters require this equipment upstream of the meter to protect the internals. Foreign objects can cause meter damage, excessive wear, or inaccurate measurement. Housing need to be compatible with applicable piping specifications and pressure ratings.
2. Pressure gages or transmitters—an accurate pressure determination is required since the measured liquid is always metered at a pressure higher than atmospheric and is in a compressed form. A compressibility factor must be established and applied to the metered volume.
3. Temperature transmitters and devices—liquid is generally measured at some temperature other than base 60°F. in order to correct the volume to a net 60°F volume, a volume correction must be made. This can be done manually, in a computer (flow) or directly by the meter. An additional thermowell is normally installed adjacent to the transmitter to allow checks to be made periodically.
4. Pulse generating device—a pulsing device connected directly to the meter is required for transmitting the metered volume and for proving the accuracy of the meter. The pulse rate varies with meter size and type and typically may be 1000 or 8400 pulses/Bbl for PD meters and 500, 1000 pulses/Bbl for turbine meters.
5. Registering devices—a local register should be provided to show gross readings. This device is typically either a mechanical or electronic totalizer. Increasingly Measurement Flow Computers are utilized to accumulate not only the pulses but also the temperature and pressure variables and in some systems the flowing real time density.
6. Pulsation dampers—meters located in line with positive displacement pumps should use a dampening device to eliminate the pulsating effects. The typical device usually consists of an appendage to the pipeline, which has an inflatable bag inside and is pre-charged with nitrogen.
7. Air eliminators—air or vapor eliminators should be installed preceding the meter since large compressed volumes will tend to expand through the meter causing over speed and serious damage. An air eliminator is usually an enlarged section of pipe or vessel that is vented and provided with a level control device.
8. Back pressure control—some installations require a method of controlling backpressure on the meter sufficiently high to prevent vaporization across the meter. API MPMS Chapter 5, section 3 recommends that the backpressure be equal to or greater than twice the pressure drop across the meter at maximum flowing conditions plus 1.25 times the equilibrium vapor pressure at flowing temperature.
9. Straightening vanes—turbine meters preferably should have straightening vanes upstream of the meter. The vanes condition the liquid flow profile for the turbine meter. If straightening vanes are not used, sufficient straight run upstream and downstream piping must be provided to condition the flowing stream.

METER PERFORMANCE

The meter's operating performance should be verified by proving it periodically. The frequency of proving is guided by the type of operations, i.e. batched systems, regulatory requirements, agreements between parties and operational experience. Therefore the prover is an integral part of any metering system. For the meter to register accurately its registration needs to be compared to a device with a known volume. All provers' function in the same manner, they measure the volume of fluid passing through the meter. The two measurements, the prover and meter, are compared in order to determine a meter factor as follows:

$$\text{Meter Factor} = \text{Prover Volume} / \text{Meter Volume}$$

This meter factor is applied to the meter's registration to correct it.

The types of provers include the following:

- Calibrated Prover Tank
- Pipe Prover
  - Bi-directional
  - Uni-directional
  - Reduced volume
  - Small volume

Master meters are utilized from time to time in specific applications.

Meters that are used to measure liquids of different densities, viscosity's or other characteristics, which may affect meter slippage or volume corrections, should have meter factors developed for each type of fluid. Additionally, meters subjected to varying rates of flow should be proved at a sufficient number of points to allow preparation of a performance curve and an appropriate meter factor selected from this curve. For all practical purposes, a change of 15 percent from the base rate is considered to be sufficient change to warrant multiple proving's.

Although there are a number of prover types and proving techniques vary in complexity they all function in the same basic manner. The basic concept of all pipe provers is the same; accumulate the registration of the meter during a time when the displacer through a pipe of known volume. This known volume is called the calibrated section and is precisely defined by the detector switches. As the displacer passes the detector switch, it activates the prover counter to commence collecting the pulses generated by the meter and when the displacer activates the second detector, the counter stops its accumulation of pulses. Adjusting the total pulses by the meters K-factor yields the meter's indicated volume, which can then be compared to the provers known volume. This ratio yields the meter factor for the given meter.

Prover Calibration—the known volume of the provers calibrated section must be precisely determined. This calibration process for pipe provers is known as a waterdraw calibration. Tank provers are calibrated utilizing a similar process known as waterfill method. Using precisely calibrated Test Measures the prover is calibrated in a manner similar to proving a meter. As water is circulated through the prover, it moves the displacer. When the displacer activates the first detector, a solenoid valve is typically activated and the fluid is displaced from the prover into the Test Measure, stopping when the second detector is activated. The process is repeated until a repeatability criterion is met. The volume recorded from these calibration runs is corrected to base conditions and then related to the volume of the calibrated section. This volume at base conditions is called the Prover Base Volume, and becomes the basis for the meter proving process. The process of calibration, the "Waterdraw" is covered in the API MPMS standard Chapter 4, section 7 "Field Standard Test Measures" and a new standard API MPMS Chapter 4, section 9 "Prover Calibration"

SAMPLING

While some of the physical properties needed to complete the measurement transaction, such as temperature and pressure are measured using electronic transmitters. A means needs to be utilized to determine the density of the transaction. This can be accomplished on-line using a vibrating element densitometer, as is done typically in refined product, light hydrocarbon liquids and NGL's or off-line using a sampling system to capture the sample for analysis.

Regardless of which test method is used for analysis one must first start with a sample of the hydrocarbon liquid to be analyzed. Samples can be obtained through two principle means:

- Manual Sampling

- Automatic Sampling

Manual sampling procedures and equipment are addressed in ASTM D 4057 (API Ch 8.1) “Manual Sampling of Petroleum and Petroleum Products”. Automatic sampling is covered in ASTM D 4177 (API Ch 8.2) “Automatic Sampling of Petroleum and Petroleum Products”. The successful and accurate analysis of any sample depends on the appropriate handling and mixing of that sample from point of extraction to its placement into the analytical apparatus. These procedures are covered in ASTM D 5854 (API Ch 8.3) “Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products”.

While both sampling methods can be used with metering systems, depending on the quality parameter, most metering systems use the Automatic Sampling method. From the sample receiver multiple samples can be extracted for the various analytical tests.

SUMMARY

A dynamic metering system allows a degree of flexibility, that static measurement does not, in operations, while meeting the exacting requirements for Custody Transfer Measurement. A typical system is composed of multiple individual components that interact to provide the information, conditioning or control, which results in accurate measurement.

The quality of those individual components, their installation, maintenance and calibration has a direct bearing on accurate measurement. As we move from the mechanical systems to the electronic environment and increased automation, these requirements will not decrease, but substantially increase. The increasing use of Vibrating Element densitometer’s for real-time density determination, especially for hydrocarbon stream with varying compositions, requires increased verification and proving of the primary device. The miniaturization of electronics has resulted in Measurement Flow Computers with the robustness and processing capabilities, which used to reside on a mainframe computer. However, this requires that the flow computer be “calibrated” through the use of audit trails for both input data and calculation processes.

As we utilize new metering technology such as helical turbine meters and integrate it into existing systems we must search for measures for verification of its performance. Similar verification/proving concerns exist as the industry explores the use of other metering technology such as Coriolis Meters and Liquid Ultrasonic Meters. Both of these meters are inferential meters similar to turbine meters. However, they require signal processing integrated over time in order to generate a pulse output signal from their electronics packages. The Coriolis meter measures the deflection force generated by the fluid moving through the sensors. The Ultrasonic meter measures the time it takes for a pulse to travel from one sensor to another. The signals of both are processed and a volume is imputed from the signal.

The key to accurate measurement in a dynamic mode is the requirement that all measurements must be verified against a “master” device, which is traceable to NIST (National Institute for Standards and Technology) or a NMI. This verification must be performed on an ongoing basis.