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Section 1—Allocation Measurement

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FOREWORD

The Allocation Measurement Standard, *API Manual of Petroleum Measurement Standards*, Chapter 20.1, was developed in response to an indicated desire by federal and state regulatory agencies to reference API measurement standards. In 1986 various regulatory agencies began requiring the petroleum industry to use the *API Manual of Petroleum Measurement Standards* for allocation measurement on federal and state leased lands. The edition of the manual in place then was written specifically for custody transfer measurement, which was inappropriate for allocation measurement. Although the petroleum industry does a substantial amount of allocation measurement, the industry was being required to use a standard that did not apply.

The API Committee on Petroleum Measurement responded in the spring of 1987 by commissioning a task group to survey the industry and determine if an *allocation standard* was necessary. After determining that the need did actually exist, an API working group was commissioned in the fall of 1987 to develop the scope and the field of application for such a standard.

A second survey in the fall of 1987 was conducted to verify the types of equipment used, the typical design of measurement facilities, and the typical operating procedures used for allocation measurement. This document, Chapter 20.1 of the *API Manual of Petroleum Measurement Standards*, is the result of that industry survey and the efforts of the working group.

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Suggested revisions are invited and should be submitted to Measurement Coordination, Industry Services Department, American Petroleum Institute, 200 Massachusetts Avenue, NW, Washington, DC 20001.

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Chapter 20—Allocation Measurement

SECTION 1—ALLOCATION MEASUREMENT

1.1 Introduction

A purpose of industry standards and procedures is to ensure that all parties are treated fairly in a transaction. Another is to ensure uniformity, that is, to provide a fixed method of solving a problem or completing a task that will be repeatable by anyone with the necessary skills or experience. Allocation measurement, properly applied, can ensure fair treatment. Reference to industry standards as the underlying basis of allocation measurement assures uniformity of procedures and practices.

Although allocation measurement may not meet the requirements for custody transfer measurement in all cases, it is still possible to refer to existing custody transfer industry standards for the basis of measurement. Where this allocation standard does not specifically address a measurement related issue, it should be assumed that custody transfer standards apply.

If industry standards were not used as the basis of measurement, contracts would have to include volumes of technical details or the parties would have to refer to their individual company policies. By utilizing the industry standards, we can measure tolerances, design metering systems, determine if an orifice plate is flat enough, gauge a tank level, and so forth without having to address all the issues separately.

Allocation measurement was developed to reduce capital and operating costs without sacrificing the objective of treating all parties fairly and equally. The individual allocation meters determine what fraction of the total production or income from a system is attributable to an individual lease or well. The total production or payments are determined with custody transfer quality systems and procedures, but the associated allocation system may not fully meet industry standards for custody transfer. For example, in an allocation system it may be necessary to meter multiphase streams rather than require separation equipment at each lease. Allocation metering systems may assume constant flowing temperatures to eliminate the need for temperature recording systems. Other compromises may be made, but they must be applied uniformly throughout the system.

In some fields the streams are very similar in temperature, pressure, flow rate and composition, but most have wide variability in one or more of these areas. For example, to be sure that a lease with lean gas is treated fairly with respect to another lease in the allocation system with rich gas, periodic testing to help better define both the quality and quantity of the stream must be established with either portable or stationary sampling, calibration, separation, and/or proving systems. The net effect of such measures is to greatly reduce capital expenses and operating expenses while still defining a representative quantity and quality for the stream.

The quality and quantity determinations in an allocation system must represent the individual lease contributions.

Allocation measurement provides a sound basis for distributing production or income and is a common practice, contractually agreed to by many different companies and interests. It may allow leases and fields with marginal economics to exist, since requiring custody transfer quality systems and measurements would require more expense than could be supported.

The purpose of this standard is to set appropriate guidelines for implementing allocation measurement.

1.2 Scope

This document provides design and operating guidelines for liquid and gas allocation measurement systems. Included are recommendations for metering, static measurement, sampling, proving, calibrating, and calculating procedures.

1.3 Terms

1.3.1 DEFINITIONS

- a. *Allocation measurement* is measurement using metering systems for individual producing leases or wells and specific procedures to determine the percentage of hydrocarbon and associated fluids or energy contents to attribute to a lease, well, or working interest owner, when compared to the total production from the entire affected reservoir, production system or gathering system.
- b. *Beta ratio* is the ratio of the orifice bore to the internal diameter of the meter tube.
- c. *Commingle* means to combine the hydrocarbon streams from two or more wells or production facilities into a common tank or pipeline.
- d. *Full well stream* is the total amount of produced fluids from a hydrocarbon producing well.
- e. *Indicated volume* is the difference between opening and closing meter readings.
- f. *K Factor* relates the output signal or registration of a meter to a unit of quantity (mass, volume, energy).
- g. *Multiphase* is the term used to describe the fluid from a well that is composed of any combination of hydrocarbon gases, hydrocarbon liquids, or produced water.
- h. *Oil-continuous emulsion* is an oil and water mixture in which the oil is the major component and the water is in suspension.
- i. *Pipeline condensate* is the liquid formed in a pipeline by a phase change from gas to liquid resulting from a change in temperature and/or pressure. Pipeline condensate is occasionally referred to as retrograde condensate in some segments of the industry.
- j. *Raw composite volume* is the uncorrected, indicated, multiphase volume determined by a full well stream metering system.
- k. *Recoverable liquid hydrocarbon content (GPM)* is the amount of theoretical or actual liquid component products recoverable from a stream.
- l. *Residual atmospheric liquid* is the fluid remaining in a stock tank after weathering at atmospheric pressure and ambient temperature.
- m. *Shrinkage factor* is the ratio of a liquid volume at stock tank or some defined intermediate conditions to that liquid volume at metering conditions.
- n. *Stabilized liquid* is hydrocarbon liquid which has reached equilibrium.
- o. *Stock tank* is an atmospheric tank used to store hydrocarbon liquids.
- p. *Stock tank conditions* are atmospheric pressure and 60 °F.
- q. *Theoretical production* is the volume of crude oil corrected to stock tank conditions.
- r. *Three-phase* is the term used to describe the fluid from a well composed of hydrocarbon liquid, gas, and produced water.
- s. *Uncorrected totalized volume* is that volume registered on a totalizer to which no adjustments for temperature and pressure have been applied.
- t. *Water-continuous emulsion* is a water and oil mixture in which the water is the major component and the oil is in suspension.
- u. *Water cut* is the volume percentage of water in a combined hydrocarbon and water stream.

1.3.2 ABBREVIATIONS

- a. C_{uf} is the conversion units factor for maintaining proper units within the equations.
- b. CPL is the volume correction factor for the effects of pressure on liquid.
- c. CPS is the volume correction factor for the effects of pressure on steel.
- d. CSW is the sediment and water correction factor to adjust for material coexisting with, yet foreign to, petroleum liquid. $CSW = (1 - S\&W / 100)$.
- e. CTL is the volume correction factor for the effects of temperature on liquid (refer to API MPMS Chapter 12.2, Paragraph 12.2.5.3).
- f. CTL_o is the volume correction factor for the effects of temperature on crude oil; a non-dimensional value.
- g. $CTL_{o,m}$ is the volume correction factor for the effects of temperature on crude oil at metering conditions.
- h. $CTL_{o,s}$ is the volume correction factor for the effects of temperature on crude oil at standard conditions.
- i. $CTL_{o,st}$ is the volume correction factor for the effects of temperature on crude oil at stock tank conditions.
- j. CTL_w is the volume correction factor for the effects of temperature on produced water; the ratio of produced water density at meter temperature to base temperature (see Appendix A for method of computation).
- k. $CTL_{w,m}$ is the volume correction factor for the effects of temperature on produced water at metering conditions.
- l. $CTL_{w,s}$ is the volume correction factor for the effects of temperature on produced water at standard conditions.
- m. CTS is the volume correction factor for the effects of temperature on steel.
- n. $D_{e,m}$ is the density of crude oil/water emulsion at metering conditions.
- o. *gpm* refers to gallons per minute.
- p. *GPM* refers to gallons of hydrocarbon liquid per mcf (1000 standard cubic feet) of natural gas.
- q. M_e is the mass of crude oil/water emulsion as indicated on the flowmeter.
- r. *MCF* is one thousand cubic feet of gas.
- s. *MF* is the meter factor of the flow meter; a non-dimensional value that corrects the quantity as indicated on a meter to the actual metered volume.
- t. *SF* is the shrinkage correction factor (see 1.7.4.4).
- u. $V_{o,st}$ is the volume of crude oil corrected to stock tank conditions.
- v. $V_{w,st}$ is the volume of produced water corrected to stock tank conditions.
- w. $X_{w,m}$ is the volume fraction of water cut in the crude oil/water mixture at metering conditions.
- x. $X_{w,s}$ is the volume fraction of water cut in the crude oil/water mixture at standard conditions.
- y. $X_{w,st}$ is the volume fraction of water cut in the crude oil/water mixture as measured by static methods of sampling under stock tank conditions.

1.4 Referenced Publications

The following standards, codes, and specifications are cited in this standard:

A.G.A.¹/GPA²

Code 101-43 *Standard Compression and Charcoal Test for Determining Natural Gasoline of Natural Gas*

Report No. 7 *Measurement of Gas by Turbine Meters*

¹ American Gas Association, 1515 Wilson Boulevard, Arlington, Virginia 22209.

² Gas Processors Association, 6526 East 60th Street, Tulsa, Oklahoma 74145.

API

RP 12R1 *Recommended Practice for Setting, Connecting, Maintenance, and Operation of Lease Tanks*

Std 2545 *Method of Gauging Petroleum and Petroleum Products*

Std 2550 *Measurement and Calibration of Upright Cylindrical Tanks*

Std 2551 *Measurement and Calibration of Horizontal Tanks*

Manual of Petroleum Measurement Standards

Chapter 2.2B, "Calibration of Upright Cylindrical Tanks Using Optical Reference Line Method"

Chapter 3.1B, "Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging"

Chapter 4, "Proving Systems"

Chapter 5, "Metering"

Chapter 5.2, "Measurement of Liquid Hydrocarbons by Displacement Meters"

Chapter 5.3, "Measurement of Liquid Hydrocarbons by Turbine Meters"

Chapter 6, "Metering Assemblies"

Chapter 7, "Temperature Determination"

Chapter 8, "Sampling"

Chapter 8.1, "Manual Sampling of Petroleum and Petroleum Products"

Chapter 8.2, "Automatic Sampling of Petroleum and Petroleum Products"

Chapter 9.1, "Hydrometer Test Method for Density, Relative Density (Specific Gravity) or API Gravity Crude Petroleum and Liquid Petroleum Products"

Chapter 9.2, "Pressure Hydrometer Test for Density or Relative Density"

Chapter 9.3, "Thermohydrometer Test for Density, Relative Density and API Gravity" (under development)

Chapter 10.1, "Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method"

Chapter 10.2, "Determination of Water in Crude Oil by Distillation"

Chapter 10.3, "Determination of Water and Sediment in Crude Oil by the Centrifuge Method" (Laboratory Procedure)

Chapter 10.4, "Determination of Sediment and Water in Crude Oil by the Centrifuge Method" (Field Procedure)

Chapter 10.8, "Standard Test Method for Sediment in Crude Oil by Membrane Filtration"

Chapter 10.9, "Coulometric Karl Fischer (under development)"

Chapter 11.1, "Volume Correction Factors"

Chapter 11.2.1, "Compressibility Factors for Hydrocarbons: 0-90 °API Gravity Range"

Chapter 11.2.2, "Compressibility Factors for Hydrocarbons 0.350-0.637 Relative Density (60°F/60°F) and -50°F to 140°F Metering Temperature"

Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"

Chapter 14.1, "Collecting and Handling of Natural Gas Samples for Custody Transfer"

Chapter 14.3, "Concentric, Square-Edged Orifice Meters" (A.G.A. Report No. 3)

Chapter 14.3, Part 2, "Specification and Installation Requirements"

Chapter 14.6, "Continuous Density Measurement"



Chapter 14.8, “Liquefied Petroleum Gas Measurement”

Chapter 18.1, “Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck”

ASTM³

D1240 (ASTM-IP⁴) *Petroleum Measurement Table* (Table 3)

GPA²

Std 2145 *Physical Constants for Paraffin Hydrocarbons and Other Components of Natural Gas*

Std 2177 *Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*

Std 2186 *Tentative Method for the Extended Analysis of Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Temperature Programmed Gas Chromatography*

1.5 Liquid Quantity Measurement

1.5.1 GENERAL DESIGN CONSIDERATIONS

This section deals with the measurement of liquid phase fluids. It does not apply to liquid/gas two phase flow measurement.

If the measurement scheme has flow parameters which are similar to custody transfer quality measurement, the applicable API MPMS chapters should be used as a guide. However, if the measured liquid is at or above its bubble point, the following design considerations should be used:

- a. Special effort must be made to minimize the pressure drop in the system. Pressure reduction may cause solution gas to break out from the liquid. Gas in a liquid stream will cause erroneous measurement. The following procedure should be used:
 1. Select and size the flow meter.
 2. Install the flow meter upstream of a control valve.
 3. Minimize the distance between the separator outlet and the flow meter.
 4. Locate the flow meter below the liquid level in the test separator.
- b. The flow meter should be selected to minimize the potential of erosion if a significant amount of abrasives are present in the flow stream.
- c. The materials for construction of the meter should be selected to eliminate the potential for stress corrosion from the chlorides or hydrogen sulfide in the produced water. The temperature, pressure, and composition of the streams must also be considered during the design and selection of materials.
- d. When flowing or ambient temperature affects meter performance, consideration should be given to insulating or heat tracing the flowmeter system.

1.5.2 MEASUREMENT EQUIPMENT CONSIDERATIONS

1.5.2.1 Displacement Meters

Variations in the viscosity of the liquid will affect meter performance. These variations are due to varying water cut, oil gravity, and temperature. If a significant viscosity variation occurs, a series of meter factors may be developed to account for different operating conditions. Variations in meter performance may also be reduced by using similar measurement procedures, proving techniques, and types of equipment at all allocation facilities.

The system design and selection of equipment should be in accordance with API MPMS Chapter 5.2, as applicable.

³ American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

⁴ Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR, England.

1.5.2.2 Turbine Meters

API MPMS Chapter 5.3 discusses the use of turbine meters on single phase fluids. Single phase has generally been used to mean liquid only. API MPMS Chapter 5 may also be extended to liquid-liquid (oil and water) single phase measurement as in many allocation measurement schemes.

The scope, field of application, system design, selection of meters, installation, operation, and maintenance of turbine meters used in allocation measurement schemes are found in API MPMS Chapter 5.3, Paragraphs 5.3.1, 5.3.2, 5.3.3, 5.3.4, and 5.3.6. In allocation measurement schemes, the fluid characteristics may vary substantially and this variation will in turn affect the performance of the turbine meter.

1.5.2.3 Differential Pressure Devices

The most common differential pressure meter used in the allocation measurement of liquids is the flange tapped, concentric orifice type. The primary element should be constructed and installed in accordance with the specifications contained in the latest revision of API MPMS Chapter 14.3.

The differential pressure measuring device (transmitter or bellows chart recorder) shall be mounted below the orifice flange taps with the gauge lines sloping one inch per foot toward the secondary element. The gauge lines should be as short in length as possible and installed to prevent any vapor traps. Generally, on a bellows secondary element, the gauge lines should be connected to the top connections of the bellows assembly. However, depending on the liquid being measured, it may be preferable to connect to the bottom bellows connections.

The orifice flange tap connections shall be located on the side of the meter tube at 90 degrees from vertical. Depending on the liquid being measured and ambient conditions, it may be necessary to use a seal system to prevent plugging, corrosion, freezing, and other problems of the gauge lines and secondary element. The seal system shall consist of seal pots installed at the orifice taps with the pots, gauge lines, and secondary element filled with a suitable seal liquid.

Accessory instrumentation to determine temperature, density, water content, and other factors shall be installed as necessary, depending on the application and type of measurement (for example, volumetric vs. mass) required.

The calculations required to determine the volume of the measured liquid are also dependent upon the application and the type of measurement. Refer to API MPMS Chapters 14.3 and 14.8 to determine the appropriate calculations and procedures.

1.5.2.4 Tanks

This section deals with tanks and single phase fluids.

A reference point shall be affixed at the gauge hatch from which measurements are made. The distance from the reference point to the tank bottom or datum plate is the reference depth. The reference depth distance shall be stenciled near the gauge hatch. If this distance varies by more than 0.5 inches, concern should be raised whether there is an obstruction or excessive bottom sediment. The tank valves and connections shall be designed to allow for complete isolation during shipment. Refer to API Recommended Practice 12R1 and Standard 2545.

The tank shall be calibrated in accordance with Standard 2550, Standard 2551, or API MPMS Chapter 2.2B to determine total and incremental volumes.

The reading and reporting of fluid temperatures shall be in accordance with API MPMS Chapter 7 as applicable.

A representative sample of the fluid shall be drawn for quality determination. Methods for drawing the sample include sample cocks, running sample, and all level sample. Refer to API MPMS Chapter 8.1.

1.5.2.5 Mass Measurement

1.5.2.5.1 Direct Mass Measurement (Coriolis Effect)

The direct mass measurement method described in this section is limited to the use of meters operating on the Coriolis effect principle.

A Coriolis mass flow meter determines the fluid flow on a mass basis. A typical Coriolis mass flow meter is composed of metallic tube(s) through which the fluid flows. The tube(s) are made to vibrate at their natural or harmonic frequencies by means of an electromagnetic driving mechanism. The flowing fluid generates a Coriolis force that is directly proportional to the mass flow rate of the fluid. The Coriolis force can be detected by various means, converted and output to other devices.

When a Coriolis mass flow meter is used for allocation measurement, it is usually installed at the outlet of the separation equipment, as shown in Figure 1. The meter should be installed in such an orientation so as not to cause false flow measurement when measuring the crude oil/water mixtures or condensate. Special guidelines described previously should be considered. No industry-wide tests have been conducted to determine the uncertainty of these devices.

1.5.2.5.2 Indirect Mass Measurement

Indirect mass measurement refers to the method of measuring the fluid quantity by multiplying a volumetric measurement and a density measurement performed at flowing conditions.

Volumetric measurement can be obtained using a primary volumetric device installed in accordance with the *API Manual of Petroleum Measurement Standards* (MPMS) as applicable.

Liquid density can also be measured by a static method.

Depending on the physical state of the liquid sample, static density measurement should use one of the following methods:

- a. API MPMS Chapter 9.1.
- b. API MPMS Chapter 9.2.
- c. API MPMS Chapter 9.3.
- d. A laboratory electronic density meter.
- e. A gas chromatograph.

Indirect mass measurement systems should meet the general requirements in accordance with API MPMS Chapters 14.4, 14.6, 14.7, and 14.8.

1.5.2.6 Other Types of Measurement Devices

Other types of measurement devices may be used for allocation measurement, although generally accepted industry standards do not currently exist for some of these devices.

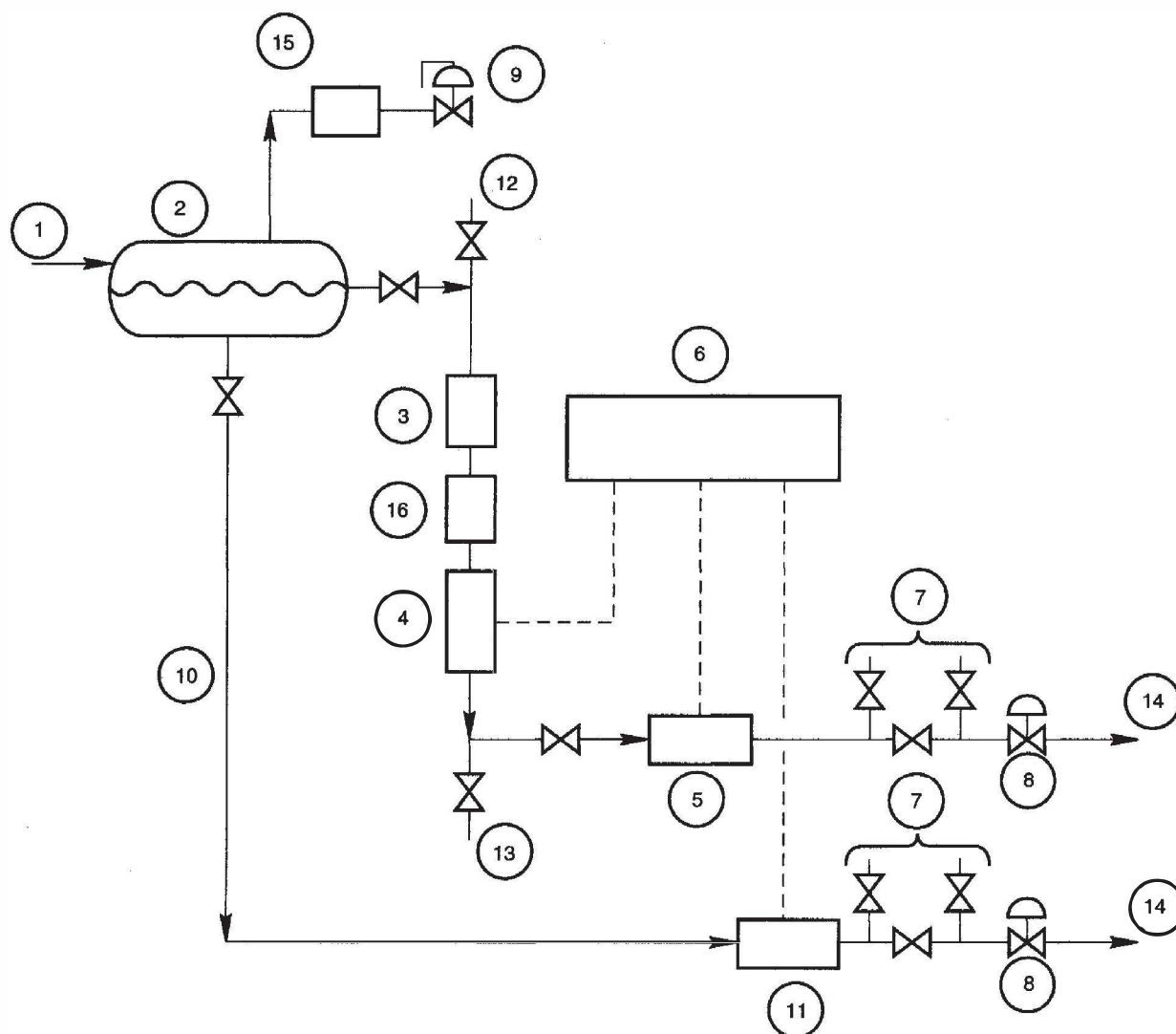
1.6 Liquid Sampling Procedures

In liquid allocation measurement applications the components of the liquid stream need to be accounted for both qualitatively and quantitatively. This may be accomplished through the use of spot sampling or an automatic sampling system.

1.6.1 SPOT SAMPLING SYSTEMS

Spot sampling of liquids may be used where flow rates are constant, and the composition of the produced liquid is stable. This might also be an appropriate technique where production is so low that the use of an automatic sampling system is not financially justifiable.

When spot sampling is used, several factors need to be considered which may affect the accuracy of the sample results. These include:



- | | |
|---------------------------|---------------------------------|
| 1. Production Fluid Inlet | 9. Back Pressure Regulator |
| 2. Test Separator Vessel | 10. Free Water Flow Line |
| 3. Static Mixer | 11. Free Water Flow Meter |
| 4. Water Cut Analyzer | 12. Calibration Fluid Fill Port |
| 5. Emulsion Flow Meter | 13. Drain/Sampling Port |
| 6. Net Oil Computer | 14. To Processing Facility |
| 7. Flow Meter Prover Loop | 15. Gas Meter |
| 8. Control/Dump Valve | 16. Sample |

Note: ----- Dotted lines denote electronic signals from instruments

Figure 1—Flow Meter System

- a. Use of a sample probe.
- b. Stream flow conditioning (mixing).
- c. Sample cylinder type selection.
- d. Knowledge of basic liquid characteristics (especially vapor pressure).

1.6.2 AUTOMATIC SAMPLING SYSTEMS

1.6.2.1 Basic Concepts

The proper use of automatic sampling systems is described specifically in API MPMS Chapter 8.2. The basic concepts outlined in that standard are applicable to allocation measurement. Those concepts are:

- a. Stream conditioning.
- b. Use of sample probe.
- c. Sample extractor.
- d. Sample controller.

1.6.2.2 Variations

However, some considerations for automatic sampling apply for production allocation applications that involve variations from API MPMS Chapter 8.2. These include the following items:

- a. Probe location. The performance of the sampling system depends on a liquid full line with a properly conditioned flow stream. The sample probe should be placed upstream of the liquid dump valve.
- b. Sample receivers. In some cases of high volatility in produced liquids, it is preferable to store and transfer the sample in receivers designed to maintain the sample substantially above vapor pressure, that is, piston cylinders. Receiver size will depend on sample size, sample frequency, sample period, and transport regulations.
- c. Sample control. The sample system may be controlled in proportion to the flow through the output of an allocation meter (turbine, positive displacement, or others). The system may also be controlled with the use of a pneumatic output from level control devices located on the production vessel. In this manner, the system is operating during the dump cycle of the production separator.
- d. Sample size. The sample size should be sufficient for the intended analytical device.

1.7 Liquid Quality Measurement

1.7.1 INTRODUCTION

The purpose of this section is to describe and illustrate methods that can be employed to determine the water content in a hydrocarbon/water mixture stream, as well as the shrinkage, gravity, and volume of the hydrocarbon liquid. The measurement thus obtained can then be used to compute the net amount of hydrocarbon liquid in a mixed stream.

1.7.2 WATER CUT ANALYZERS

Water cut analyzers are those devices that provide an on-line, continuous measurement of water content in a hydrocarbon/water mixture under flowing conditions.

This section describes selection considerations for a water cut analyzer and accessory equipment. This section also discusses more specific guidelines and requirements pertaining to three types of commonly used water cut analyzers: a capacitance analyzer, a density analyzer, and an energy absorption analyzer. The selection and accuracy of the water cut analyzer should be agreed to by the allocation parties and where applicable, should be consistent with regulatory requirements.

It is recognized that water cut analyzers other than those described herein exist. This document is not intended to preclude the use of such devices.

1.7.2.1 Selection of a Water Cut Analyzer

When selecting a water cut analyzer, the manufacturer should be consulted, and consideration should be given to the following items:

- a. The anticipated range of water cut and expected performance in this range.
- b. The anticipated range of liquid flow rates (or flow velocity) and expected performance in this operating range.
- c. The range of operating pressure, pressure losses through the water cut analyzer, and consideration whether the pressure in the analyzer is adequate to prevent the liquid from flashing.
- d. The effect of varying liquid properties (for example, viscosity, oil gravity, and water density) on the performance.
- e. The operating temperature range and the applicability of automatic temperature compensation.
- f. The material of construction of the analyzer and the effect of corrosive contaminants on its operating life.
- g. The quantity and size of foreign solid particles that may be carried in the liquid stream, for determining the potential for erosion.
- h. The space and location for the water cut analyzer installation and the on-line calibration facility that is required.
- i. Types of secondary elements (for example, electronic processor unit and readout device) and the acceptable maximum distance between these secondary elements and the water cut analyzer.
- j. The compatibility of the output electronic signal, if applicable, to other associated devices and the method of adjusting this output signal.
- k. The class and type of pipe connections.
- l. Power supply requirements for the analyzer(s) and the secondary elements.
- m. Electrical code requirements.
- n. Type, method, and frequency of calibration.
- o. The presence of paraffin, tar, and other impurities that may coat the sensing element.

1.7.2.2 Installation of a Water Cut Analyzer and Accessory Equipment

A schematic diagram of a typical installation arrangement for a water cut analyzer and the accessory equipment is shown in Figure 1. Considerations for this arrangement include the following:

1.7.2.2.1 Water Cut Analyzer

Installation requirements vary with different types of water cut analyzers. Sections 1.7.2.3, 1.7.2.4, and 1.7.2.5 provide more specific guidelines for the three types of water cut analyzers mentioned above. Some general requirements are described below:

To minimize pressure loss and thus prevent flashing of the hydrocarbon liquid, a water cut analyzer should be installed upstream of the dump valve and as close to the separator as possible. Minimum amount of upstream piping components should be used so that the pressure drop between the test separator and the analyzer does not exceed two pounds per square inch (14 kPa) at the maximum flow rate.

Installing the analyzer at a certain vertical distance below a test separator may also be considered as an alternative. This installation scheme effectively increases the liquid pressure as a result of a static head gain of the liquid column.

The mounting position of the analyzer is critical. Installation guidelines specified by the manufacturer should be strictly followed.

Whenever possible, the analyzer should be installed in such a way that it measures the full liquid stream. However, if installation of the analyzer in the slip stream is necessary or unavoidable, care must be taken to ensure homogeneous mixing in the main liquid stream.

To promote mixing of the liquid stream, a static mixer may be installed immediately upstream of the analyzer. However, when selecting a static mixer, the added pressure loss should be considered.

To facilitate periodic calibration, the water cut analyzer should be installed so that it can be conveniently isolated from the normal flow path. A typical piping arrangement is shown in Figure 1.

1.7.2.2.2 Test Separator

The performance of a water cut analyzer is affected by the presence of free gas in the liquid stream. A test separator should be properly designed and sized to provide adequate retention time for complete gas and liquid separation.

A test separator can also incorporate an additional mechanism, if required, to further separate the liquid phase into a free water phase and an oil/water emulsion phase. With the free water separated, the water cut in the emulsion stream is reduced even though the overall water cut from the incoming stream may be relatively high. This constitutes three-phase separation.

A test separator should include liquid level sensing and flow control devices, and back pressure regulators in all outgoing streams.

Other design features may be incorporated as desired.

1.7.2.2.3 Flow Meters

Flow meters should be installed and operated in accordance with 1.5.1 (Liquid Quantity Measurement—General Design Considerations).

1.7.2.2.4 Net Oil Computer

As depicted in Figure 1, the typical net oil computer receives electronic signals from the flow meter(s) and the water cut analyzer. It computes, totals, and displays the individual amount of hydrocarbon and water. Temperature compensation, pressure compensation, or other capabilities may also be included in the net oil computer.

Depending on the required electrical codes, the net oil computer can be located in the general vicinity of the water cut analyzer, or it can be designed for installation at a certain distance away from the water cut analyzer.

1.7.2.3 Capacitance Water Cut Analyzer

The capacitance water cut analyzer operates on the principle that there is a significant difference in the dielectric constants of water and hydrocarbon liquids. By measuring the capacitance (dependent upon dielectric constant) of the hydrocarbon/water emulsion, the water cut in the emulsion can then be determined.

The proper use of the capacitance water cut analyzer requires attention to calibration and the use of the following special guidelines:

1.7.2.3.1 Calibration

1.7.2.3.1.1 Factory calibration. The relationship between dielectric constant and water cut varies with different types of hydrocarbons and water. The analyzer should be calibrated in the factory using the hydrocarbon liquid and water identical or similar to those in the actual application. A calibration curve between the actual water cut and probe output should be developed and incorporated into an associated electronic processor device.

1.7.2.3.1.2 Recalibration. At installation and periodically after use, the analyzer should be properly zeroed and spanned in accordance with the procedure specified by the manufacturer.

1.7.2.3.2 Special Guidelines

Special guidelines and requirements are to be considered and emphasized regarding the following factors which affect performance of capacitance water cut analyzers. These are in addition to the items described in 1.7.2.1.

1.7.2.3.2.1 Water cut level and nature of emulsion. The capacitance water cut analyzer is appropriate as long as the liquid mixture is an oil-continuous emulsion which occurs at a water cut below a certain level. Measurement errors would result at higher water cuts wherein the emulsion becomes water-continuous. The maximum allowable water cut is dependent upon the physical properties of the hydrocarbon liquid, the water, and the operating conditions. Therefore, caution should be exercised to ensure the liquid mixture is in the oil-continuous emulsion range when a capacitance water cut analyzer is used.

1.7.2.3.2.2 Mixing. The capacitance water cut analyzer should be mounted in a vertical pipe run with the axis of the sensing probe parallel to the direction of the flow. It can be installed either in an up flow or a down flow position, but tests indicate the down flow position is preferable. The vertical mounting position usually results in a more uniform mixing of the hydrocarbon/water mixture stream.

1.7.2.3.2.3 Operating temperature. Significant variations in the temperature of the liquid can also affect the performance of the analyzer because dielectric constants of both hydrocarbon and water are functions of temperature. For greatest accuracy, the analyzer should be calibrated in the range of normal operating conditions.

1.7.2.3.2.4 Hydrocarbon and water properties. Dielectric constants differ with different types of hydrocarbon and water. Significant variation in the properties of these liquid components would also affect the performance of the analyzer. Therefore, the analyzer should be calibrated with representative hydrocarbon liquids and limited in subsequent applications to those liquids with similar properties.

1.7.2.3.2.5 Free gas. The water cut is generally undermeasured when there is free gas in the liquid stream. Prudent separator design and installation guidelines described in previous sections should be followed to minimize or eliminate the free gas.

1.7.2.3.2.6 Paraffin deposition. Paraffin buildup on the analyzer decreases its sensitivity and results in measurement errors. Remedial practices may include chemical treatment of the liquid stream, heat tracing, and frequent cleaning of the analyzer.

1.7.2.4 Density Water Cut Analyzers

A density water cut analyzer is based on the density difference between hydrocarbon liquid and water. By measuring the density of the hydrocarbon/water mixture, the water cut in the mixture can be approximated.

Several types of density meters can be adopted for this water cut analyzer application. These include, but are not limited to, vibrating element density meters, Coriolis mass flow meters, differential pressure density meters, and nuclear density meters.

1.7.2.4.1 Calibration

Unless otherwise requested, most manufacturers will calibrate a density meter on two or more fluids of known density, such as water, varsol, diesel, or air.

Upon installation and periodically thereafter, the equipment shall be verified or recalibrated. Verification can be done by fluid sample, master density meter, or tank gauging method. Recalibration is accomplished by filling the sensor with fluids of known density and calibrating the output appropriately. Verification and recalibration are important for the optimum performance of density measuring equipment and shall be provided for in the design of facilities using this equipment.

1.7.2.4.2 Special Guidelines

Special guidelines and requirements are to be considered and emphasized regarding the following factors that affect performance of capacitance water cut analyzers. These are in addition to the items described in 1.7.2.1.

1.7.2.4.2.1 Accuracy of density meter. The accuracy of the measured emulsion density determines the accuracy of water cut measurement. When selecting a density water cut analyzer, the accuracy of the density meter should be examined to determine the corresponding accuracy on water cut measurement.

1.7.2.4.2.2 Fluid temperature. An accurate temperature measuring device must be incorporated to measure the fluid temperature. Temperature measurement is needed for computing water cut and performing temperature compensation of the density meter.

1.7.2.4.2.3 Free gas. In the liquid stream, free gas lowers the apparent density and may cause the water content to be significantly underestimated. Extreme care must be taken to minimize or eliminate the free gas.

1.7.2.4.2.4 Hydrocarbon and water density determination. A density water cut analyzer requires that the individual hydrocarbon and water densities be predetermined before measurement. Special care must be taken to ensure that these densities are determined under metering pressure.

1.7.2.4.2.5 Variation of hydrocarbon and water densities. The density water cut analyzer requires that the hydrocarbon and water densities remain fairly constant during measurement. Reverification of these densities should be performed periodically.

1.7.2.4.2.6 Variation of operating conditions. Since the liquid stream being measured is normally at its bubble point condition, significant variations in pressure and temperature from their normal conditions may affect the performance of the analyzer. An uncertainty analysis may be performed to determine the effect, and proper corrections may be applied if necessary.

1.7.2.4.2.7 External vibration. Excessive external vibration may be detrimental to the performance of the vibrating element density meter and the Coriolis mass flow meter. If these types of water cut analyzers are used, they should be installed at a certain distance away from the vibration sources, such as pumps and compressors. Vibration isolation devices may also be used if necessary.

1.7.2.4.2.8 Paraffin deposition. Paraffin buildup on the analyzer decreases its sensitivity and results in erroneous measurement. Remedial practices may include chemical treatment of the liquid stream, heat tracing, and frequent cleaning of the analyzer.

1.7.2.5 Energy Absorption Water Cut Analyzers

An energy absorption water cut analyzer is based on the principle of electromagnetic energy absorption. The difference in energy absorption rates between water and hydrocarbons allows this analyzer to measure water content. The operating principle is not affected by changes of the individual oil and water densities in the stream. The deposition of paraffin and other impurities on the sensor will have less effect on accuracy than with other analyzers.

1.7.2.5.1 Calibration

This analyzer may be partially or fully calibrated at the factory. However, final calibration and verification of factory settings should be conducted at the installation site using the actual fluid to be monitored. For optimum performance, recalibration and reverification should be conducted periodically. Refer to the manufacturer's calibration procedures.

1.7.2.5.2 Special Guidelines

Special guidelines and requirements are to be considered and emphasized regarding the following factors that affect performance of capacitance water cut analyzers. These are in addition to the items described in 1.7.2.1.

1.7.2.5.2.1 Installation orientation. The sensor should be installed in a vertical position with the fluid flowing downward.

1.7.2.5.2.2 Water cut and nature of emulsion. The energy absorption analyzer is accurate as long as the liquid mixture is an oil-continuous emulsion that has a water cut less than the manufacturer's specified level. The performance of this type of analyzer in the water-continuous region may be affected by variations in the flowing velocity and by the properties of the fluid. Measurement errors can result at higher water cuts wherein the emulsion becomes water-continuous.

1.7.2.5.2.3 Fluid temperature. Even with temperature compensation, large variations in process temperature may affect accuracy, requiring recalibration.

1.7.2.5.2.4 Free gas. Free gas in the liquid stream will significantly affect the accuracy of the water cut measurement. Any free gas in the stream to be monitored must be eliminated.

1.7.2.5.2.5 Paraffin deposition. Significant paraffin deposits on the sensor may slightly affect the analyzer's accuracy. These deposits may be reduced or eliminated by one or more of the following methods: maintaining sufficient velocity through the sensor housing, maintaining relatively constant process temperature, heat tracing, and frequent cleaning.

1.7.3 TANK GAUGING METHODS

1.7.3.1 Total Volume Measurement

Tank gauging may be used to determine the production from individual leases or wells. The production is periodically diverted from the common production facilities for a period of time, and the total amount of fluid is measured in accordance with 1.5.2.4 (Tanks), which addresses single phase measurement of liquids. The basic methods for obtaining tank gauges are manual, using steel tape and bob, and automatic tank gauging systems (refer to API MPMS Chapter 3.1B).

1.7.3.2 Interface Detection

Sampling, gauging paste on a steel tape, side window, or other interface detection techniques can be used to determine the level of transition from water to oil. That data can then be used to calculate corresponding volumes.

Sampling procedures are given in API MPMS Chapter 8.1. A representative sample of the fluid shall be drawn for quality determination. Methods for drawing the sample include, but are not limited to, sample cocks, composite spot samples, running samples, and all level samples.

1.7.3.3 Computation Procedures

Refer to API MPMS Chapter 18.1 for a calculation procedure that may be used for the computation of oil and water present in a tank gauge.

1.7.3.4 Tank Gauging Limitations

An emulsion must break out into separate oil and water components, or a provision for an emulsion breaker must be included to obtain meaningful results from the tank gauge. Different crude/water emulsions will allow more or less well defined transitions to develop

as they are allowed to separate due to buoyancy differences. However, should the separation not occur during the time allotted for the test, the oil segment will contain some water, and the water some oil. This will directly affect the accuracy of interface detection and cause a measurement error.

The character of the emulsion produced should be evaluated prior to the design and installation of tank gauge facilities, thus ensuring the validity either in production allocation or recalibration application.

1.7.3.5 Water Analysis from Samples

Determination of impurities, usually sediment and water in the liquid sample obtained, is important to the final result of the allocation measurement process. There are several techniques for determining the percentage of water in liquid samples. These techniques include the following:

- a. Centrifuge method (see API MPMS Chapters 10.3 and 10.4). Special centrifuge tubes marked in 1 milliliter (ml) increments should be used if high water content is anticipated.
- b. Distillation method (refer to API MPMS Chapter 10.2).
- c. Karl Fischer method (refer to API MPMS Chapter 10.9).

Each of these methods has advantages involving factors such as accuracy, ability for performance in the field, time, and cost. The priorities in these areas should be scrutinized carefully before selecting the type of method to be used.

1.7.3.6 Sediment and Water Content

Determination of sediment and water content should be in accordance with API MPMS Chapters 10.1, 10.3, 10.4, or 10.8.

1.7.4 SHRINKAGE FACTOR

1.7.4.1 Introduction

At the allocation measurement point, a hydrocarbon liquid is normally at its bubble point (equilibrium vapor pressure) condition. When this liquid is discharged to a stock tank at atmospheric condition, the light components in the hydrocarbon evaporate, causing a reduction in liquid volume. Therefore, a correction term, defined herein as *shrinkage factor*, may need to be applied to correct the measured liquid volume from metering condition to stock tank condition.

This section describes a procedure for determining shrinkage factors. The procedure involves obtaining a known volume of a representative liquid sample from the flow line using a pressurized sample cylinder. The sample is then allowed to stabilize at atmospheric conditions, and the volume of the remaining liquid is measured. The shrinkage factor is then computed based on the initial and final liquid volumes.

1.7.4.2 Sample Cylinder

Figure 2 shows the assembly of two types of sample cylinders: a single chamber sample cylinder and a piston sample cylinder.

For field shrinkage determination, a single chamber cylinder is recommended. The sample cylinder body, fittings, and valves should be constructed of stainless steel or other suitable metals. The volume of the sample cylinder should be at least 300 cubic centimeters. The total volume between the cylinder inlet valve and the outlet valve should be determined prior to usage.

For laboratory shrinkage determination, the piston chamber cylinder may be used. The cylinder volume should be at least 300 cubic centimeters.

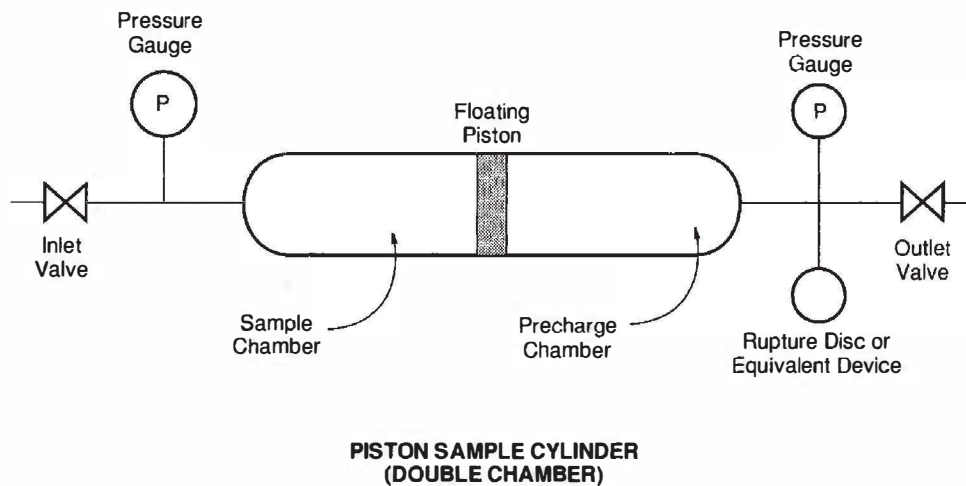
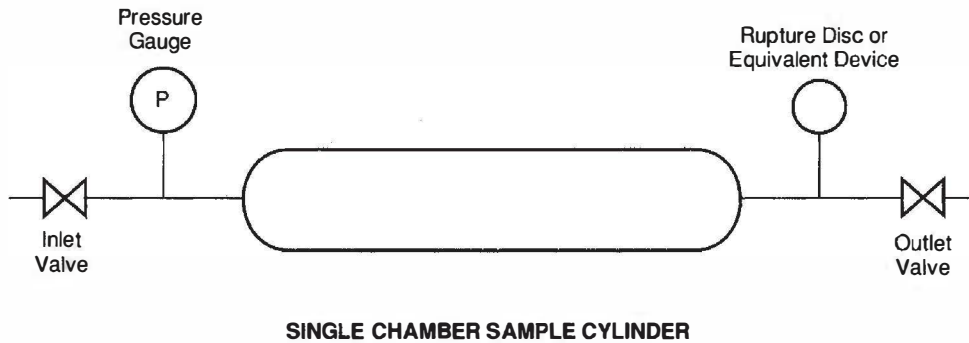


Figure 2—Sampling Cylinders

1.7.4.3 Spot Sampling Procedure

The procedure for spot sampling involves the following steps:

- a. For the single chamber sample cylinder, fill the sample cylinder with liquid prior to sampling. If a piston sample cylinder is used, fill the precharge chamber with a pressurized gas at a pressure higher than the line pressure at the sampling point.
- b. With all valves on the sample cylinder closed, connect the sample cylinder to the manifold sample valve as shown in Figure 3.
- c. Open the manifold sample valve.
- d. Open the purge valve slowly.
- e. Purge the line to ensure any debris or foreign objects are forced out of the line.
- f. Hold the sample cylinder at approximately a 45-degree angle downward with the sample source connected to the top valve of the cylinder.
- g. Slowly open the sample cylinder inlet valve.
- h. Slowly open the cylinder outlet valve or the precharge valve on a dual chamber cylinder.

- i. Proceed slowly—a minimum of five minutes should be taken to complete the sampling process.
- j. Considerations for safety purposes are the following:
 - 1. *Outage* should be taken to allow for expansion of the hydrocarbon liquids in the cylinder after collection due to ambient temperature changes in shipment.
 - 2. The sample cylinder should be kept cool if possible, and excessive increases in temperature should always be avoided.
 - 3. For single chamber cylinders, 20 percent of the sample cylinder volume is usually sufficient outage to allow for expansion of typical high pressure crude oil and condensates from oil and gas production facilities.

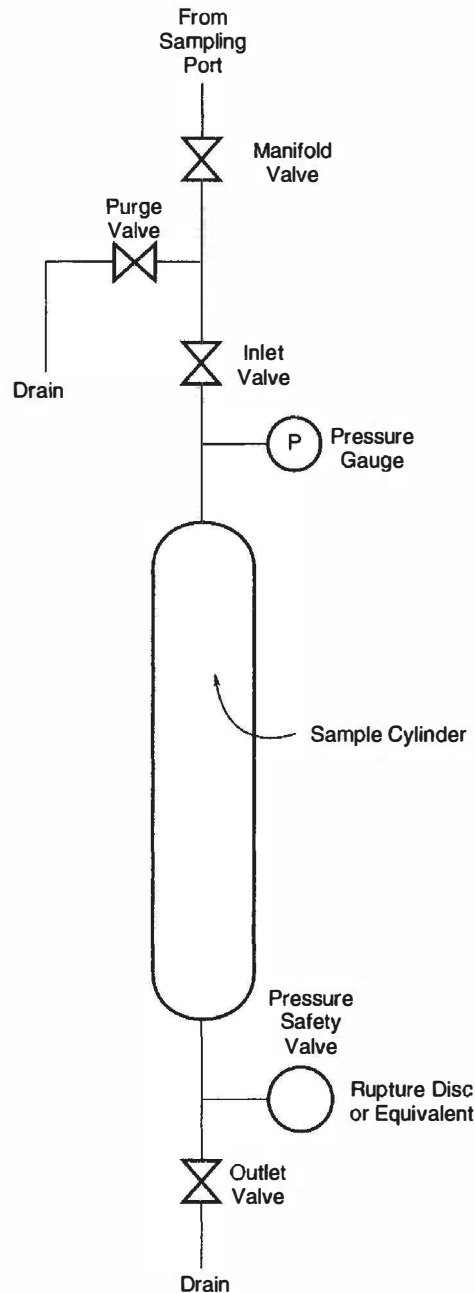


Figure 3—Sampling Assembly