Manual of Petroleum Measurement Standards Chapter 20—Allocation Measurement

Section 1—Allocation Measurement

FIRST EDITION, SEPTEMBER 1993

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AMERICAN PETROLEUM INSTITUTE

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Measurement Coordination

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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, 1220 L Street, Northwest, Washington, D.C. 20005.

CONTENTS

Page

SECTION 1—ALLOCATION MEASUREMENT

Figures

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. $CSW = (1 - \text{S\&W} / 100)$.

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]/GPA[2]

Code 101-43	*Standard Compression and Charcoal Test for Determining Natural Gasoline of Natural Gas*
Report No. 7	*Measurement of Gas by Turbine Meters*

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[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, "Coulemetric 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"

ASTM[3]
D1240 (ASTM–IP[4]) *Petroleum Measurement Table* (Table 3)

GPA[2]
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.

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[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.

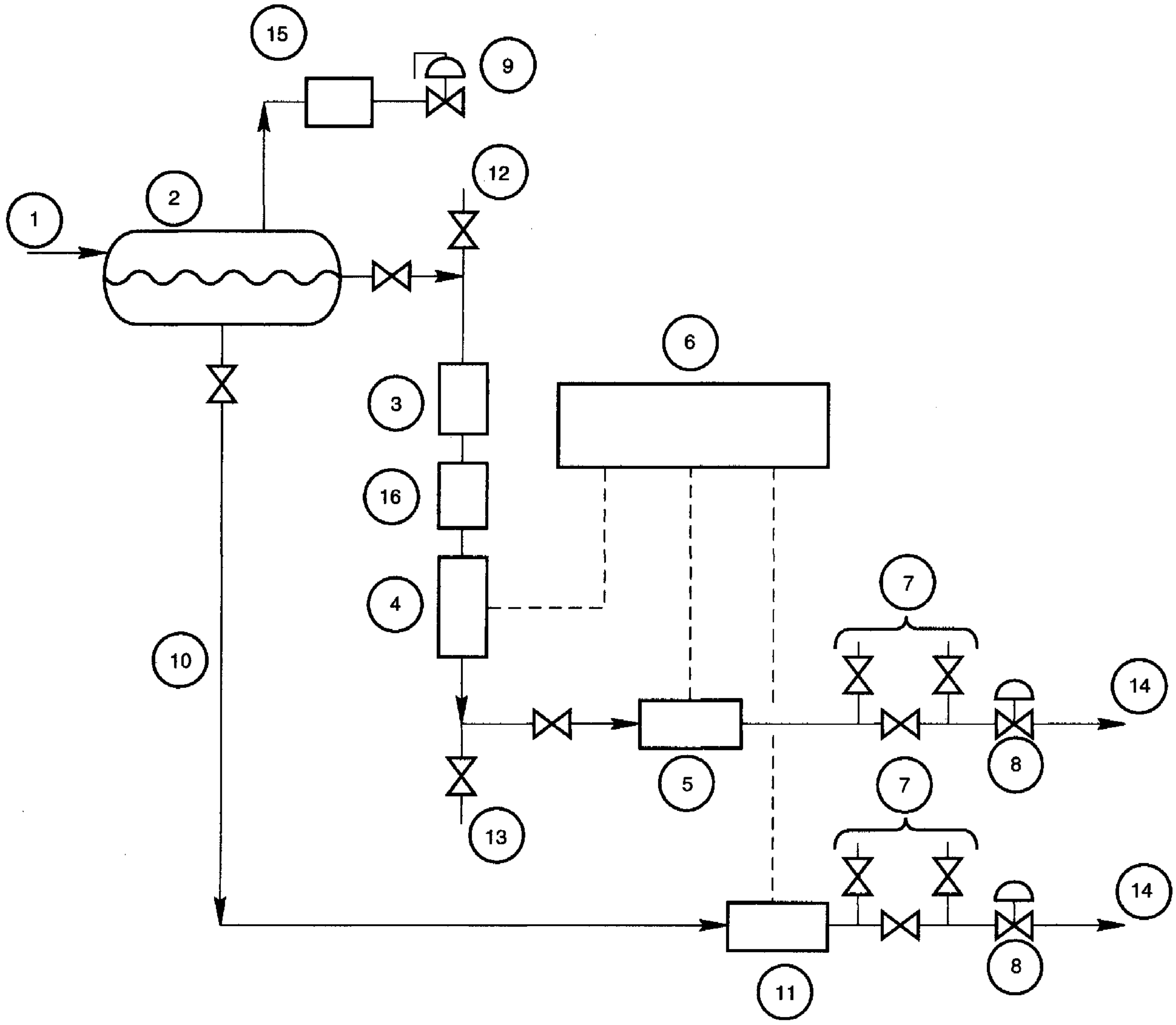
1.6 Liquid Sampling Procedures

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

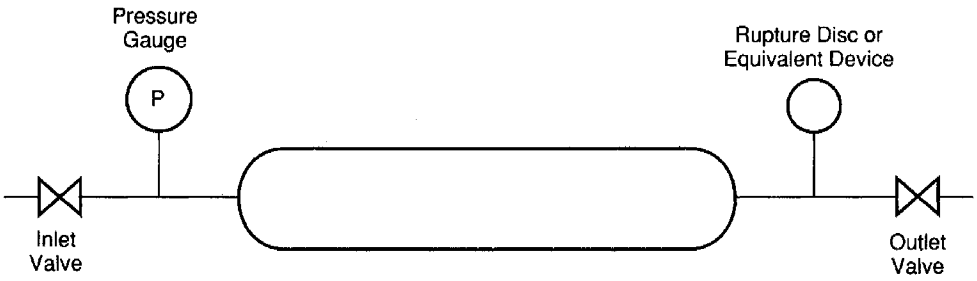
This section describes a procedure for determining shrinkage factors. The procedure involves obtaining a known volume of a representative liquid sample from the flow line using a pressurized sample cylinder. The sample is then allowed to stabilize at atmospheric conditions, and the volume of the remaining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

1.7.4.2 Sample Cylinder

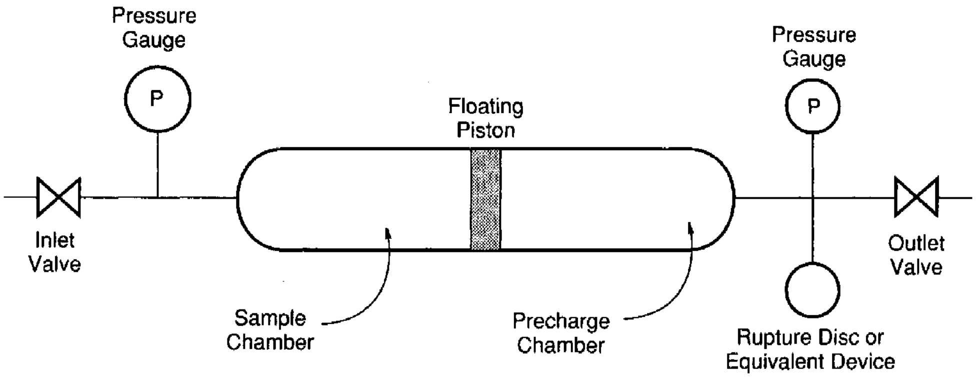
Figure 2 shows the assembly of two types of sample cylinders: a single chamber sample cylinder and a piston sample cylinder.

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.



SINGLE CHAMBER SAMPLE CYLINDER



PISTON SAMPLE CYLINDER (DOUBLE CHAMBER)

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.

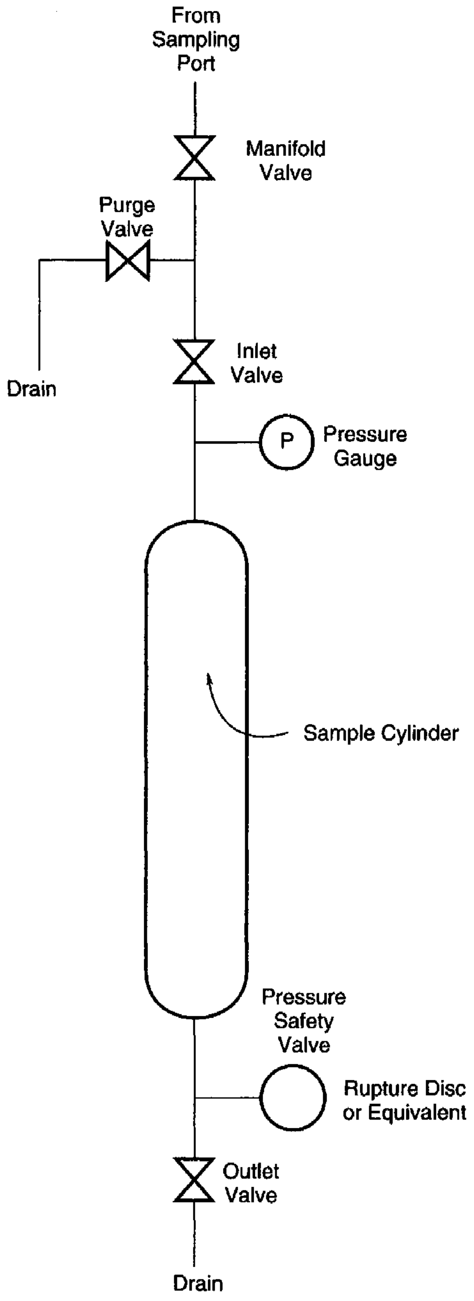


Figure 3—Sampling Assembly

4. This volume is measured by displacing the liquids in the cylinder with the hydrocarbon liquid and measuring the displaced liquid into a graduated cylinder.
5. When approximately 80 percent of the cylinder volume is displaced, the source liquid is shut off by closing the top valve on the cylinder, and the aqueous layer is drained off the cylinder until just less than 20 percent of the volume is received.
6. It is recommended that a small volume of water remain in the cylinder.
7. When the lab receives the sample, it will pressurize the cylinder to a point above the original sample pressure so that the liquid is again in a single phase and the shrinkage factor can be determined.
8. When sampling using a piston cylinder, sample until 80 percent of cylinder volume is achieved.

k. Close the outlet valve.

l. Close the cylinder inlet valve and the manifold sample valve.

m. Disconnect the sample cylinder from the manifold sample valve.

n. Record the line temperature and the line pressure by measuring as close to the sampling point as possible.

CAUTION: Thermal expansion must be considered for safety reasons, and thus the cylinder should not be completely filled. If filled more than 80 percent, the cylinder should be chilled during transportation to avoid potentially hazardous situations due to thermal expansion.

1.7.4.4 Shrinkage Factor Determination (Field)

The sample captured for shrinkage determination should represent the liquid at metering conditions. The testing procedure for determining the shrinkage factor involves the following steps:

a. Determine the temperature of the sampled fluid when the sample is obtained, and record the pressure.

b. With the charged sample cylinder in an upright position, slowly bleed the sample into a clear calibrated graduated cylinder that is open to atmospheric pressure. The graduated cylinder should be large enough to contain the entire sample.

c. Allow the sample to stabilize until no gas bubbles are visible.

d. Record the total volume of the sample remaining in the graduated cylinder. Record the temperature of the sample.

e. If water is present in the final sample, determine its water cut using a recognized method.

f. Obtain a sample of water free hydrocarbon and determine its API gravity at 60°F or density in kg/m^3 at 15°C.

g. Compute the shrinkage factor using the following equation:

$$\text{Shrinkage factor} = \frac{(V_f - (V_f \times X_w)) \times (CTL)_f}{(V_i - (V_i \times X_w)) \times (CTL)_i}$$

Where:

V_f = total volume of final sample in the graduated cylinder.
V_i = total volume of initial sample in the sample cylinder.
X_w = volume fraction of water in the final sample.
$(CTL)_f$ = volume correction factor based on temperature of final sample.
$(CTL)_i$ = volume correction factor based on temperature during sampling.

1.7.4.5 Theoretical Flash Calculation

Multiple flash programs exist that can be used to perform a flash calculation. The closer to reservoir conditions the sample is obtained, the better the results will be. Care should be taken when selecting the appropriate equation of state for various crude oils.

1.7.4.6 Gravity Determination

1.7.4.6.1 Atmospheric Samples

To determine the gravity of atmospheric samples, use API MPMS Chapters 9.1 or 9.3.

1.7.4.6.2 Pressurized Samples

To determine the gravity of pressurized samples, use API MPMS Chapter 9.2.

1.7.4.6.3 Stock Tank Samples

Stock tank gravities may be determined by withdrawing a representative sample from the stock tank as described in API MPMS Chapter 8 and by determining the relative density (specific gravity) or observed gravity with the proper hydrometer in accordance with API MPMS Chapter 9.1 or 9.3.

1.7.4.6.4 High Vapor Pressure Samples

A high vapor pressure product's relative density may be determined in the field by a permanently installed gravitometer operating at actual measurement pressure and temperature. These gravitometers are calibrated by the use of pycnometers as described in API MPMS Chapter 14.6.

Laboratory density determination of high vapor pressure samples may be performed by a laboratory electronic density meter fitted with an exterior pressure cell. Calibration of this type of meter may utilize gas standards with known components or the *two point* technique using air and water. In some cases where it is known that all of the sample is eluted from the column and each component is known and is adequately separated, gas chromatography may be used. This is probably only acceptable with light hydrocarbons such as ethane through the natural gasolines. In these cases Gas Processors Association (GPA) Method 2186 or GPA Method 2177 is suggested.

1.8 Liquid Proving and Calibration Techniques

1.8.1 PROVING A MASTER METER

An allocation master meter is selected, maintained, and operated to provide a secondary standard for the proving of another meter. A displacement or a turbine meter that satisfies the proving criteria given below is typically used for a master meter. The displacement or turbine meter shall be a complete assembly and shall remain intact during proving, transportation, and operation. Master meters are not temperature compensated. Refer to API MPMS Chapters 4, 5, and 6 for more details.

The master meter must be proved at a rate approximating the flow rate at which it is to be used. The fluid used to prove the master meter must be similar to the fluid of the line meter to be proved. A change in the meter's factor can be experienced when the flow rate varies. When calibrated on a liquid other than water, the rangeability and calibration curve of the meter may change. Thus, the K factor or the meter factor should be obtained on similar fluids and conditions. Each meter is different and a new meter factor or K factor curve must be established along with the operating range for each master meter.

The master meter assembly is connected in series to a prover close enough to minimize corrections for pressure and temperature. The pipe prover, small volume prover, or the master meter assembly shall have connections to obtain the pressure and temperature of each unit. If the prover and master meter differ in temperatures and pressures during the proving runs, then both units shall have appropriate liquid corrections applied. The desired flow rate for the proving run should be established and operated long enough to achieve a steady temperature and pressure. The temperature and pressure are recorded for each run.

An electronic counter is connected to the meter and started and stopped by switches on the prover. Traditional pipe provers and small volume provers utilizing pulse interpolation are acceptable.

The following steps are then performed:

a. Use a minimum of four flow rates covering the anticipated operating range to establish a meter factor or a K factor curve for each master meter.

b. Five out of six consecutive runs at each flow rate with 0.05 percent repeatability are required.

c. To obtain the meter factor or the K factor, average the acceptable five runs for each flow rate.

d. To obtain the master meter factor or the master meter K factor, add the highest and lowest meter factors or K factors determined in Item c and divide by two. The meter factor or K factor so calculated is known as the *mean average meter factor* or *mean average K factor.*

The individual meter factor or K factors at each rate are then checked against the mean average meter or K factor, respectively. If the meter factor or K factor of each test run is within ±0.5 percent of the mean average, then the test is acceptable. A plot of flow rate versus meter factor or K factor should be established.

These meter factors or K factors will be used from month to month to determine the K factor drift. Each month the meter will be tested in the above manner and new meter factor or K factor established. The new average mean meter factor or K factor will be compared against the original mean average meter factor or K factor. If these results check within ±1.0 percent, the test is acceptable. When the tests do not meet these parameters, the meter shall be repaired and recalibrated to the above guidelines. A new mean average is established on a meter when a repair is performed or if a new meter is put in service.

Example:

Flow Rate	% Deviation	Pulses/Barrel	K Factor
20 gpm	0.46%	37400	Mean
30 gpm	0.25%	37320	Average
40 gpm	0.21%	37304	is
55 gpm	0.47%	37054	37227

1.8.2 ON-SITE PROVING OF ALLOCATION METERS

When crude oil is metered for custody transfer, it is generally in a stabilized condition (weathered). Most of the dissolved natural gas will separate from the oil at low pressure. When oil is pumped through the meters, the increased pressure should reduce the possibility of any remaining gas from breaking out of solution as it is metered.

For allocation measurement, oil and condensate may be metered before it is stabilized. This is the case when a liquid is metered as it is dumped from a test or production separator at separator equilibrium temperature and pressure. Care must be exercised to ensure that the design of these systems minimizes the pressure drop upstream of the meters.

In some instances the oil or condensate is transferred from the separator to a holding tank upstream of metering. A pump is used to force the liquid through the meter and into the pipeline. In this case a correction for effect of pressure on the liquid (CPL) is used in the calculation of the meter factor to correct for the increase in pressure above the holding tank pressure. A commonly used method for proving a separator (allocation) meter is the master meter method. Other methods listed in API MPMS Chapter 4 may also be used.

Allocation meter proving should meet or exceed contractual guidelines and governmental regulations.

1.8.2.1 Equipment Considerations

Equipment necessary for proving an allocation meter typically includes the following:

a. A displacement or turbine master meter.

b. A dual board pulse counter with the capability of a simultaneous gate circuit.

c. Preamplifiers for turbine meters, if not built into dual board pulse counters.

d. Properly shielded cables.

e. A power source for the prover counter.

f. Hoses in good condition with a pressure rating, which exceeds working pressure, for proving along with bleeder valves for depressurizing. The system shall be pressure-tested quarterly.

g. Thermometers capable of temperature readings to 0.5°F (0.2°C) or better. The calibration shall be maintained within 0.5°F (0.2°C).

h. A pressure gauge accurate to 0.25 percent of full-scale operating range. The gauge should not exceed 150 percent of the maximum expected operating pressure.

i. A stop watch for determining the instantaneous flow rate of the allocation meter.

1.8.2.2 Proving Procedures for Batch Metering

The following steps are used in batch meter proving:

a. Connect the master meter to the proving manifold and make sure the master meter is properly grounded.

  1. The master meter can be installed either upstream or downstream of the line meter as long as all protective devices that service the meters are upstream, such as strainers, filters, and air eliminators.
  2. There shall be no devices between the master meter and line meter that will change the flow rate, operating or fluid characteristics of the flowing stream, such as control and/or dump valves.
  3. All valves used to divert the flowing stream to the master meter must have a means of verifying that the valves have established a positive seal.
  4. The master meter should be installed as close as possible to the line meter being proved to minimize deviation in temperature and pressure that would require volume corrections.
  5. A stable and typical flow rate should be established through both meters to purge the system and stabilize the temperature and pressure prior to proving the line meter, if possible.

b. Open the upstream proving manifold valve carefully to introduce a small amount of fluid to the master meter while observing the pressure gauge on the master meter.

c. Once the pressure is equal to the separator pressure and the master meter is full of liquid, open the downstream valve on the proving manifold and close the main block valve on the meter manifold.

d. Open the bleed on the main block valve to check the integrity of the seal. It may be necessary to purge the main block and bleed valve to determine if there is any buildup of foreign material in the bleeder valve.

e. Pay close attention to the settings of the *dump* control valve on the separator. Snap-acting control valves are recommended and should be set to open and close rapidly to avoid a slow rise and fall of the actuator.

f. If the dump valve is throttling and causes a continuous but varying flow, set the controller to maintain a steady flow.

A common error in separator batch meter service is to oversize or undersize the meter. Consult with the meter manufacturer concerning the service conditions.

1.8.2.2.1 Flow Rate Determination

a. For batch metering systems, the flow rate in gallons per minute (gpm) can be determined by timing the "dump" cycle and reading the meter's totalizer for the volume delivered.

$$\text{Flow rate} = \frac{\text{Volume in batch cycle} \times \text{UCF}}{\text{Cycle time}}$$

Where:

UCF = Units conversion factor

Example:

$$\frac{0.500\text{ bbl} \times (60\text{ sec/min}) \times (42\text{ gal/bbl})}{30\text{ seconds}} = 42\text{ gpm}$$

b. An alternative way to determine the flow rate is to use the prover counter and the master meter. Reset the prover counter and start the counter at the beginning of the batch cycle and time the cycle. Record the pulses from the prover counter and calculate the flow rate as follows:

$$\text{Volume in batch cycle} = \frac{\text{Pulses from prover counter}}{\text{Master meter K factor (pulses/bbl)}}$$

$$\text{Flow rate} = \frac{\text{Volume in batch cycle} \times \text{UCF}}{\text{Cycle time}}$$

Example:

Master meter K factor = 36,000 pulses per barrel (bbl)
Pulses from prover counter = 18,000
30 seconds for batch cycle

$$\text{Volume in batch cycle} = \frac{18{,}000\text{ pulses}}{36{,}000\text{ pulses/bbl}} = 0.5\text{ bbl}$$

$$\text{Flow rate} = \frac{0.500\text{ bbl} \times (60\text{ sec/min}) \times (42\text{ gal/bbl})}{30\text{ seconds}}$$

$$\text{Flow rate} = 42\text{ gpm}$$

1.8.2.2.2 Proving Runs

A proof run begins when the dump valve opens. The following procedure is followed:

a. Reset the prover counter to zero to begin the proving cycle.

b. When the dump valves begin to open, depress the start or count button. Some batch cycles may be short in duration. Several cycles may be needed to accumulate the number of desired pulses for a run. Temperature and pressures will be recorded and averaged for each proof run.

c. If the line meter being proved is temperature compensated, apply a temperature correction factor only to the master meter readings. If the line meter is not temperature compensated, a temperature correction factor will be applied to both meters.

d. Under normal separator metering conditions the liquid is at equilibrium and a correction factor, CPL, of 1.0000 is applied.

1. Always determine the source of the fluid flow.
2. If the fluid is stored in a holding vessel at some intermediate or atmospheric pressure and is then pumped through the meters into the pipeline, the pressure correction, CPL, for the amount of the compression is applied.

3. The amount of compression used to compute the pressure correction is the difference between the holding vessel pressure and the metering pressure.

1.8.2.2.3 Meter Factor and K Factor Determination

The pulses registered on the prover counter for the master meter and the line meter are divided by the respective K factor to obtain the respective uncorrected volume flowed through the meters.

The correction factors for temperature and pressure (if applicable), along with the appropriate meter factor, should be applied to the uncorrected master meter volume.

To calculate the meter factor, divide the corrected master meter volume by the corrected line meter volume.

Calculate the meter factors in accordance with API MPMS Chapter 12.2 and the contractual agreements between all parties involved.

To determine the allocation meter K factor, calculate the master meter corrected volume and divide the line meters corrected pulses (if applicable) by the master meter corrected volume.

Example:

$$\text{K Factor} = \frac{\text{Line meter corrected pulses}}{\text{Master meter corrected volume}}$$

$$\text{K Factor} = \frac{36{,}000 \text{ pulses}}{1.0018 \text{ bbl}} = 35935.3 \text{ pulses/bbl}$$

After verifying all calculations, the meter proof runs obtained under similar conditions are compared for repeatability. For an allocation meter proving to be satisfactory, the proof runs should repeat within a tolerance of 0.5 percent.

1.8.2.2.4 Correction Factors

The basic equations used for the pipe prover and master meter to calculate the meter factor are the following:

Pipe Prover:

$$MF = \frac{BPV \times (CTS_p \times CPS_p \times CTL_p \times CPL_p)}{MRV \times (CTL_m \times CPL_m)}$$

Master Meter:

$$MF = \frac{MMV \times (MMF \times CTL_{mm} \times CPL_{mm})}{MRV \times (CTL_m \times CPL_m)}$$

Where:

MMV = master meter volume.
MMF = master meter factor.
MF = meter factor.
BPV = base prover volume.
MRV = meter registration volume.
CTL_p = correction for temperature of liquid in the prover.
CPL_p = correction for pressure of liquid in the prover.
CTS_p = correction for effect of temperature on the steel of the prover.
CPS_p = correction for effect of pressure on the steel of the prover.
CTL_{mm} = correction for temperature of liquid in the master meter.
CPL_{mm} = correction for pressure of liquid in the master meter.

CTL_m = correction for temperature of liquid in the meter.
CPL_m = correction for pressure of liquid in the meter.

Note 1: If more water is present in the liquid stream than is normally considered for custody transfer, the computation of *MF* should reflect the volume correction for the effect of temperature on the water as follows:

Pipe Prover:

$$MF = \frac{[BPV \times (1 - X_w) \times (CTL_p \times CPL_p) + (BPV \times X_w \times CTL_w \times CPL_w)] \times CTS_p \times CPS_p}{(MRV \times (1 - X_w) \times CTL_m \times CPL_m) + (MRV \times X_w \times CTL_w \times CPL_w)}$$

Where:

X_w = volume fraction of produced water in the liquid stream.
CTL_w = correction factor for temperature of produced water (see Appendix A).

Note 2: When a meter is used in low pressure service with high water cut, the equation given below can be used. The *CTL* terms (CTL_p, CTL_m, and CTL_{mm}) are computed as follows:

$$CTL = (CTL_o \times (1 - X_w)) + (X_w \times CTL_w)$$

Where:

CTL_o = temperature correction factor for the hydrocarbon.
CTL_w = temperature correction factor for the produced water (see Appendix A).
X_w = volume fraction of produced water in the stream.

Note 3: If a composite meter factor is desired, a pressure correction for the increase in pressure above equilibrium pressure may be applied to the meter factor.

The following equation is used to calculate the *CPL* correction factor.

$$CPL = \frac{1}{1 - (P - P_e)F}$$

Where:

F = compressibility factor for liquid hydrocarbons.

If vapor pressure of the product is equal to atmospheric pressure or less, then $P_e = 0$. Refer to API MPMS Chapters 11.2.1 and 11.2.2; and Chapter 12.2, Paragraph 12.2.5.4.

1.8.2.2.5 Meter Adjustment

If an allocation meter proving results in a meter factor that differs from the previous meter factor by an amount greater than 2.0 percent and less than 7.0 percent, the allocation meter shall be adjusted and reproved prior to return to service.

When a meter is out of acceptable tolerance (2.0 percent), the volume registered through that meter since the last acceptable meter proving should be adjusted according to the applicable regulatory requirements or the system agreements and contracts.

If an allocation meter proving results in a meter factor that differs from the previous meter factor by an amount equal to or greater than 7.0 percent, the allocation meter shall be repaired and reproved prior to return to service.

In systems with stable operating conditions, tolerances of ±2.0 percent are achievable.

All meters that are used for allocation purposes should be tested with a piping configuration appropriate to enhance accuracy and rangeability.

1.8.3 OFF-SITE (TRANSFER) PROVING OF ALLOCATION METERS

Transfer (off-site) meter proving requires removing the meter and local totalizer and transporting both as a unit to a stationary prover.

The following information and data for the meter and totalizer should accompany the unit to the off-site proving location:

a. Company.
b. Location.
c. Application.
d. Normal flow rate.

e. Product gravity and viscosity.
f. Temperature and pressure.

1.8.3.1 Meter Proving Requirements

Acceptable accuracy and integrity can be obtained if the items listed below are followed:

a. The piping configuration used for proving shall be the same as that used for field operation.
b. The meter shall be calibrated using a fluid of similar viscosity and gravity to the field measured fluid.
c. If possible, meters should be proved and operated using steady flow rates, temperatures, and pressures.

1.8.3.2 Meter Proving Procedures

The meter assembly is connected as close as possible in series to a prover to minimize corrections for pressure and temperature. Both the prover and the meter assembly shall be designed to obtain accurate pressure and temperature. If the temperature and pressure differ during the proving runs, required corrections will be applied. Stabilized temperature, pressure, and flow rate should be obtained prior to actual proving runs. Temperature and pressure will be recorded for each proving run. An electronic counter started and stopped by switches on the prover is connected to the meter. Traditional pipe provers and small volume provers using pulse interpolation are acceptable.

Five out of six consecutive runs at a representative flow rate with 0.25 percent repeatability are required.

1.8.3.3 Meter Factor and K Factor Determination

Meter factor or K factors shall be calculated in accordance with 1.8.2.2.3.

If required, the totalizer can be adjusted using the new K factor or meter factor. The integrity is assured by applying a security seal to the totalizer.

1.8.3.4 Meter Adjustment

If an allocation meter proving results in a meter factor that differs from the previous meter factor by an amount greater than 2.0 percent and less than 7.0 percent, the allocation meter shall be adjusted and reproved prior to return to service.

When a meter is out of acceptable tolerance (2.0 percent), the volume registered through that meter since the last acceptable meter proving should be adjusted according to the applicable regulatory requirements or the system agreements and contracts.

If an allocation meter proving results in a meter factor that differs from the previous meter factor by an amount equal to or greater than 7.0 percent, the allocation meter shall be repaired and reproved prior to return to service.

All meters that are used for allocation purposes should be tested with appropriate piping configuration to ensure accuracy and rangeability.

1.9 Liquid Calculation Procedures

1.9.1 INTRODUCTION

The volume measured by an allocation meter is adjusted according to its proportionate share of the total volume of all the allocation meters in the system. This proportionate share is applied to the corrected volume of the gathering system. The corrected volume of the gathering system (see 1.9.8) is determined by the volume registered on the custody transfer meters at the terminus of the system, plus the closing inventories minus the opening inventories. Allocation meters normally measure at the pressure of the production system.

The production and sales procedures described below allocate all liquid back to the source. These procedures do not address retrograde condensate within a gathering system or whether the retrograde condensate belongs to the producer or to the pipeline. Retrograde condensate ownership should be declared in individual contracts.

1.9.2 SHRINKAGE FACTOR

Any stream delivering production to a gathering system under pressure will require a volume correction factor to correct to stock tank or atmospheric conditions.

See 1.7.4.4 for shrinkage factor determinations.

1.9.3 SEDIMENT AND WATER (S&W) FACTORS

Any stream delivering production to a gathering system will require a sediment and water determination to be performed.

1.9.4 TEMPERATURE CORRECTION

A gathering system may contractually require temperature correction to the commingled production. If required, temperature correction devices may be installed on each location, or temperature correction factors using the API MPMS Chapter 11.1 tables may be used to correct each stream injecting into the system.

1.9.5 THEORETICAL PRODUCTION CALCULATION

This section provides procedures to calculate petroleum quantities when the liquid stream is measured with volumetric flow meters. Varying amounts of water are normally present in the liquid flow stream at the allocation measurement point. This section specifies different procedures to compute the net volumes of hydrocarbon and water under standard conditions. The amount of water present and the method of sampling will determine which procedure to use to compute theoretical production.

1.9.5.1 Field of Application

The field of application is limited to crude oil having a gravity ranging from 0° API to 90° API or a density ranging from 610.5 kg/m^3 to 1075 kg/m^3. At the metering point, the crude oil can be under bubble point conditions, and it can also contain a significantly larger amount of water than normally found at custody transfer measurement points. This publication does not apply to situations in which free gas is present. Three different calculation procedures must be considered:

a. Procedure A (see 1.9.5.2) is used when sediment and water (S&W) is considered low, that is, at normal custody transfer pipeline measurement quantities, generally less than 5.0 percent, and the sample is gathered by a static sampling method, such as proportional sampling.

b. Procedure B (see 1.9.5.3) shall be used when water cut is higher than normal and a static sampling method such as proportional sampling is employed.

c. Procedure C (see 1.9.5.4) shall be used when water cut is higher than normal and a dynamic sampling method such as an on-line water cut analyzer is employed.

1.9.5.2 Procedure A (Static Sampling)

Procedure A is used when S&W is low, for example, at normal pipeline measurement quantities, and the sample is gathered by a static sampling method such as proportional sampling. This procedure assumes gravity is determined at atmospheric conditions and corrected to standard temperature. It does not consider the gravity change that could result when the pressure is lowered and lighter hydrocarbons might flash away.

The equation for computing theoretical production is expressed as:

$$\text{Theoretical production} = \text{Indicated volume} \times MF \times SF \times CSW \times CTL$$

Where:

Indicated volume = volume of crude oil/water as indicated on the volumetric flow meter.

MF = meter factor of the volumetric flow meter.

SF = shrinkage correction factor of crude oil.

CSW = sediment and water correction factor.

CTL = temperature correction factor.

1.9.5.3 Procedure B (Static Sampling)

This procedure is used when a significantly larger amount of water than that normally found at custody transfer measurement points is encountered, and static sampling methods such as proportional sampling or grab sampling techniques are employed to obtain a representative sample from the flow line. The sample is exposed to atmospheric pressure and the water content of the sample is then determined by standard laboratory or field methods.

The equation for computing the theoretical production, that is, the net oil volume, in an oil/water emulsion is expressed as:

$$\text{Theoretical production} = \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is:

$$V_{w,st} = \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m}$$

Where:

Theoretical production = volume of crude oil corrected to stock tank conditions, that is, standard conditions.

Indicated volume = volume of crude oil/water as indicated on the volumetric flow meter.

MF = meter factor of the volumetric flow meter.

$X_{w,m}$ = volume fraction of water cut in the crude oil/water mixture corrected to metering conditions.

$CTL_{o,m}$ = temperature correction factor of crude oil at metering conditions.

SF = shrinkage correction factor of crude oil.

$V_{w,st}$ = volume of produced water corrected to stock tank conditions.

$CTL_{w,m}$ = temperature correction factor of produced water at metering conditions (see Appendix A).

A sample calculation of Procedure B is given in Appendix B, and a sample calculation in SI units (metric) is given in Appendix C.

1.9.5.4 Procedure C (Dynamic Sampling)

This procedure is used when a significantly larger amount of water than that normally found at custody transfer measurement points is encountered, and an in-line analyzer provides a continuous measurement of water cut in the crude oil/water flowing stream. The water cut thereby measured represents the volume fraction of water in the oil/water mixture at metering conditions, $(X_{w,m})$.

The equation used to compute theoretical production, that is, net oil volume, in an oil/water mixture is expressed as:

$$\text{Theoretical production} = \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for net produced water volume is :

$$V_{w,st} = \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m}$$

Where:

Theoretical production = volume of crude oil corrected to stock tank conditions, that is, standard conditions.
Indicated volume = volume of crude oil/water mixture as indicated on the volumetric flow meter.
MF = meter factor of the volumetric flow meter.
$X_{w,m}$ = volume fraction of water cut in the crude oil/water mixture at metering conditions as measured by the in-line device.
$CTL_{o,m}$ = temperature correction factor of crude oil at metering conditions.
SF = shrinkage correction factor of crude oil.
$V_{w,st}$ = volume of produced water corrected to stock tank conditions.
$CTL_{w,m}$ = temperature correction factor of produced water at metering conditions (see Appendix A).

A sample calculation of Procedure C is given in Appendix D, and an example in SI units (metric) is given in Appendix E.

1.9.6 WATER CUT DETERMINATION

Water and crude oil have different coefficients of thermal expansion. If a mixture containing an equal volume of water and crude oil at 60°F is heated, the oil will expand more than the water, and the water cut percentage will be reduced. For very small water cut, as is the case in most custody transfer situations, this effect may be small enough to be ignored. For allocation measurement installations, the water cut may vary between 0 percent and almost 100 percent. At higher percentages, the temperature effect becomes more significant.

Pressure will also affect the water cut. When a sample of emulsion is drawn from a line under pressure to atmospheric conditions, the light ends of the crude oil will flash off, reducing the amount of the oil in the sample and raising the observed water cut.

The means of determining water cut in allocation systems can be broadly categorized into two methods, that is, the static method and the dynamic method. The static method involves obtaining a sample of the emulsion or crude oil to be tested for water cut by a proportional or grab sampling technique. The dynamic method uses an electronic device such as a capacitance probe, density ratio device, or microwave probe to determine the water cut as it flows through the pipe.

To properly establish the proportion of water and crude oil in a metered quantity of emulsion, the water cut must be determined at metering conditions. For water cut obtained using the static method, the observed value must be corrected for both pressure and temperature effects to obtain the most accurate results. This is necessary because the sample used to determine the water cut will normally be at a different temperature and pressure than the stream being measured.

1.9.7 CORRECTED PRODUCTION CALCULATION

Corrected production is theoretical production corrected to equal the volume received at the outlet of a system during a given accounting period.

$$\begin{matrix}\text{Total system}\\ \text{corrected production}\end{matrix} = \text{Sales} + \text{Closing inventories} - \text{Opening inventories}$$

To calculate corrected production for any source into an allocation system, the following formula should be applied:

$$\text{Source corrected production} = \frac{\text{Source theoretical production}}{\text{Total system theoretical production}} \times \left(\text{Total system corrected production}\right)$$

1.9.8 CLOSING INVENTORY (STOCK) DETERMINATION

If a gathering system has liquid storage capacity, the volumes stored there are known as inventories or stocks. The following formula should be used to calculate each source's closing inventory for that accounting period:

$$\text{Closing inventory} = \text{Corrected production} + \text{Opening inventory} - \text{Sales}$$

Opening inventories are the previous accounting period's calculated closing inventories. In the case of new sources during any accounting period, the source's beginning inventory equals zero.

1.9.9 ALLOCATION PROCEDURES

Entitlement sales for any source are prorated based on *Available for Sale*. Available for sale is calculated by adding corrected production to opening inventories. This is done to ensure there are no negative closing inventories calculated. This allocation procedure distributes total system entitlement sales to each source based on the source's proportionate share of source available for sale to the total system available for sale. These entitlement sales are also referred to as allocation sales, which are calculated by applying the following formula:

$$\text{Source entitlement sales} = \frac{\text{Source available for sale}}{\text{Total system available for sale}} \times \left(\text{Total system entitlement sales}\right)$$

1.9.10 LIQUID PETROLEUM QUANTITY MEASUREMENT BY MASS FLOW METERS

1.9.10.1 Introduction

This section provides procedures for converting the measured petroleum quantities from mass units to volumetric units. This section also specifies procedures to compute the net volume of hydrocarbon under standard conditions. Varying amounts of water are normally present in the liquid flow stream at the allocation measurement points. The amount of water present and the method of sampling, dynamic or static, will dictate which procedure to use.

1.9.10.2 Field of Application

The field of application of this section is limited to crude oils having a gravity ranging from 0 °API to 90 °API or a density from 610.5 kg/m^3 to 1075.0 kg/m^3. At the metering point, the crude oils can be under bubble point conditions, and they can also contain a significantly larger amount of water than that normally found at custody transfer measurement points. This procedure does not apply to situations in which free gas is present. Two different calculation procedures must be considered, depending on whether the water content is measured by a dynamic method or with a static method.

1.9.10.3 Procedure A (Water Content Measured by Dynamic Method)

The on-line analyzer provides a continuous measurement of water cut in the crude oil/water flowing stream (see 1.7.2). The water cut as measured herein is expressed as the volume fraction of water in the oil/water mixture at metering conditions.

The equation used to compute net oil volume, in an oil/water mixture is expressed as:

$$V_{o,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is:

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$

Where:

$V_{o,st}$ = volume of crude oil corrected to stock tank conditions.
$V_{w,st}$ = volume of produced water corrected to stock tank conditions.
C_{uf} = conversion units factor; if using customary units, the value is $2.853 \frac{\text{kg–bbl}}{\text{lb–m}^3}$.
M_e = mass of crude oil/water mixture as indicated on the flowmeter.
$D_{e,m}$ = density of crude oil/water mixture at metering conditions.
MF = meter factor of the mass flow meter.
$X_{w,m}$ = volume fraction of water in the crude oil/water mixture adjusted to metering conditions.
$CTL_{o,m}$ = temperature correction factor of crude oil at metering conditions.
SF = shrinkage correction factor of crude oil.
$CTL_{w,m}$ = temperature correction factor of produced water at metering conditions (see Appendix A).

A sample calculation of Procedure A is given in Appendix F for customary units (English units) and in Appendix G for SI (metric) units.

1.9.10.4 Procedure B (Water Content Measured with Static Method)

The static method refers to the use of a proportional sampling technique or a grab sampling technique to obtain a representative sample from the flow line. The sample is exposed to atmospheric pressure, and the water content of the sample is then determined by standard laboratory or field methods.

The equation for computing the net oil volume in an oil/water emulsion is expressed as:

$$V_{o,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is:

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$

Where:

$V_{o,st}$ = volume of crude oil corrected to stock tank conditions.
$V_{w,st}$ = volume of produced water corrected to stock tank conditions.
C_{uf} = conversion units factor; if using customary units, the value is $2.853 \frac{\text{kg–bbl}}{\text{lb–m}^3}$.
M_e = mass of crude oil/water emulsion measured by the mass flow meter.
$D_{e,m}$ = density of crude oil/water emulsion at metering conditions.
MF = meter factor of the mass flow meter.
$X_{w,m}$ = volume fraction of water measured at the metering conditions.
$CTL_{o,m}$ = temperature correction factor of crude oil at metering conditions.
SF = shrinkage correction factor of crude oil.
$CTL_{w,m}$ = temperature correction factor of produced water at metering conditions (see Appendix A).

A sample calculation of Procedure B is given in Appendix H for customary units (English units) and in Appendix I for SI (metric) units.

1.10 Gas Quantity Measurement

1.10.1 GENERAL DESIGN CONSIDERATIONS

For custody transfer measurement, the quantities determined by the metering system must be as precise and as accurate as practically achievable. In allocation measurement systems it is essential that the individual metering systems be similar and be treated equally.

An example of such an allocation system is where individual heater-treaters and separators have not been installed in the producing locations and the full well stream is allowed to pass through the meter run without first being separated into the various phases. It is currently impossible to predict flow coefficients or meter factors for two phase or three phase flow; therefore, the measurement using a two phase flow system is not as accurate as single phase systems.

Nonetheless, it is assumed contractually that since all of the systems are operated and designed in a similar fashion, the allocation resulting from the indicated volume will be fair and representative for all the producers and interest owners.

Periodic well tests are commonly utilized to determine the quality of the well stream and to determine the volume of each phase. During these tests portable separation equipment is used to develop factors applicable to the full well stream gross indicated volume which approximates the volumes of gas, water, and condensate actually flowing through the meter run. These tests may be performed monthly, quarterly, semiannually, or even annually, and the factors developed during the testing are used for the entire period of time from one test to the next.

In systems where multiphase flow is not a problem, chromatographic analysis of the streams or test car results are commonly used to develop the information necessary to perform the allocation calculations. A chromatographic analysis may determine the energy or the recoverable hydrocarbon content of the stream. Test cars determine only the recoverable hydrocarbon content of the stream. By estimating the recovery of the components in the stream in the form of saleable liquid products, the residue gas volumes may also be estimated. By knowing the gross metered volume and the quality of the stream determined by the test car or the chromatograph at each location and the custody transfer quality determinations of the total quantity of gas and liquid streams derived from the allocation system, both the residue gas volumes and the liquid production can be allocated to each producer fairly and equitably.

1.10.2 MEASUREMENT EQUIPMENT CONSIDERATIONS

1.10.2.1 Differential Pressure Devices

There are several types of differential pressure devices for determining gas volumes through a metering system. For any differential meter, the pressure taps should be located within the horizontal to top vertical plane. The concentric orifice plate, fixed between two orifice flanges or held in place by single or dual chamber fittings, is the most common differential pressure producing device used in gas measurement. Orifice meters are covered in API MPMS Chapter 14.3.

Venturi tubes are another type of differential pressure meter. They are used when minimum pressure loss is desired or when particles in the stream might cause erosion or deposition problems. The Venturi tube consists of converging and diverging cones separated by a cylindrical throat. The differential pressure is measured at about one diameter upstream and at the throat. No modern industry-wide tests have been performed on these devices to determine uncertainty.

Wedge meters produce a differential by constricting the flow through the meter tube with a wedge that extends either from the lower or the upper wall of the pipe into the flowing stream. For multiphase flow, the wedge extends from the top of the meter run. This orientation is no different than that which would be used for either eccentric or segmental orifice plates. For single phase gas or liquid streams, the wedge is generally oriented from the bottom towards the center of the meter tube. No industry-wide tests have been performed on these devices to determine uncertainty.

Pitot tubes consisting of cylindrical probes inserted perpendicular to the flow stream are another type of differential pressure meter. Fluid flow velocity at the upstream face of the probe is reduced to zero and converted to impact pressure. This impact pressure is sensed through a small hole in the upstream face of the probe. A corresponding small hole on the downstream side of the probe senses the static pressure. The pressure differential, which relates to the flow rate, is measured between the impact and the static pressure. Averaging pitot tubes may have several openings to the flow stream and average the pressure conditions across the meter tube typically in one plane only. No industry-wide tests have been performed on these devices to determine uncertainty.

1.10.2.2 Displacement Meters

Displacement meters use fixed volume cavities to determine the quantity of fluid flowing through the metering system. Normally, displacement meters are not used for multiphase flow. These meters may incorporate compensating devices for the gravity or the temperature of the stream. Displacement meters tolerate variable or pulsating flows relatively well. Information on displacement meters, as used in gas streams, may be found in various American Gas Association (A.G.A.) Reports.

1.10.2.3 Turbine Meters

Turbine meters use a spinning propeller or set of blades in the flowing stream to infer volume flowing through the meter run. Turbine meters are not usually used for multiphase flow and, in fact, may be damaged by multiphase flow. Turbine metering systems may include compensating mechanisms for varying temperature, relative density, line pressure, or other variables. The range of a turbine meter increases with increasing density since the driving force at low flows is higher. Turbine meters are covered by A.G.A. Report No. 7.

1.10.2.4 Mass Meters

Mass meters used for allocation measurement are the Coriolis force type meters. Such meters determine the mass passing through the metering device from the Coriolis force produced by the flowing stream. No industry-wide tests have been performed on these devices to determine uncertainty.

1.10.2.5 Insertion Turbine Meters

Insertion turbine meters typically consist of two major components, the rotor head and a retractor. The retractor provides the means of supporting the rotor head, mounting fitting, pressure seal, pickup coil and preamplifier. The flow is inferred by assuming that the local velocity is related to the mean velocity in the stream. No industry-wide tests have been performed on these devices to determine uncertainty.

1.10.2.6 Vortex Shedding Meters

Vortex shedding meters are based on the principle that vortices or low pressure regions are alternately formed on opposite sides of a strut placed in a flowing stream. The mechanisms that count the vortices shedding from the element in the meter are of various designs. No industry-wide tests have been performed on these devices to determine uncertainty.

1.10.2.7 Ultrasonic Meters

Ultrasonic meters can be of either the Doppler or *transit time* type. In the former, the velocity of the fluid is inferred by measuring the frequency shift of signals that are bounced off particles in the flowing stream. In the latter type, the velocity is determined by measuring the apparent speed of sound in the direction of flow and opposite to the direction of flow. In both types, flow is inferred by assuming that the measured local velocity is related to the mean velocity in the stream. No industry-wide tests have been performed on these devices to determine uncertainty.

1.10.2.8 Other Types of Meters

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

1.11 Frequency of Proving and Calibration

1.11.1 WELL TESTS

As a minimum, annual well tests for determination of gas-oil ratio and/or deliverability should be performed. Well testing for the determination of oil, water, and gas production rates should be performed at least semiannually.

1.11.2 METER PROVING

Proving should be performed at least semiannually. Ancillary instruments for differential type meters are typically calibrated rather than proved.

1.11.3 SAMPLING

Sampling should be performed at least semiannually.

1.11.4 METER CALIBRATION

The differential pressure measurement device and accessory instrumentation shall be tested and recalibrated (if necessary) at least every six months. The orifice plate shall be removed, inspected, and replaced (if necessary) at least every six months. The meter tube shall be inspected and repaired (if necessary) at least every six years. Depending on the results of the initial inspection intervals, it may be necessary to change the frequency of the orifice plate and meter tube inspections to maintain the primary element within specifications.

1.12 Gas Sampling Procedures

In gas allocation measurement applications the quality of gas should be determined. This is accomplished with proper gas sampling procedures.

The sample shall be obtained from the flowing stream through a sample probe that samples from the center third of the pipeline. The probe is inserted through the top of the pipeline.

These procedures include spot sampling or automatic/composite sampling. Care should be taken to ensure that the same sampling procedure is used at each sample point within the system.

1.12.1 SPOT SAMPLING

Spot sampling is a procedure where a known volume of gas (determined by the cylinder size) is withdrawn from a gas stream in a manner to ensure a representative sample of the fluid flowing in the line at that time. Spot sampling is a widely used method of sampling natural gas and involves many different techniques including the following (in no particular order of preference):

a. Purge and fill methods.
b. Constant purge methods.
c. Evacuated cylinder method.
d. Reduced pressure method.
e. Liquid displacement method.
f. Helium displacement method.
g. Free floating piston method.

The selection of the appropriate technique is determined by the composition, pressure, and temperature of the gas or is specified in the operating agreement. Refer to API MPMS Chapter 14.1 for more detailed information on the above methodologies.

If allocation is component based, samples should be at least 300 cubic centimeters.

1.12.2 AUTOMATIC/COMPOSITE SAMPLING SYSTEM

An automatic/composite sampling system accumulates many small representative increments of gas over a predetermined period of time. A typical automatic/composite sampling system includes a probe, the sample pump and controller, and the sample cylinder.

If individual samples obtained are proportional to the flow rate, a higher degree of accuracy may be obtained. This procedure is important when the composition of the gas varies during the sample period. Significant factors include the amount of gas composition change and the flow rates.

1.12.3 SAMPLE PROBE

For the highest degree of accuracy, both spot sampling and automatic procedures rely heavily on a properly installed sample probe. The location of the sample probe is critical to its ability to provide a representative sample. The probe should be installed in accordance with API MPMS Chapter 14.1.

1.12.4 SAMPLE CYLINDERS

Both spot sampling and automatic sampling procedures provide for the use of a sample vessel that is suitable for the specific components of the gas being sampled. Two examples are single cavity vessels and constant pressure floating piston cylinder (variable volume) vessels. Considerations for the application of these vessels include the presence of heavy hydrocarbons, pressure, temperature, inert gases, and contaminants.

Specific consideration and installations pertaining to both procedures are found in API MPMS Chapter 14.1.

1.13 Gas Quality Measurements

To determine the relative value of the gas volume measured at the wellhead or producing location, testing should be performed to calculate either the energy content, or the recoverable liquids content of the flowing stream. Especially important is that the gas be of sufficient quality to meet pipeline specifications before delivery into a transportation system.

1.13.1 DEW POINT

There are two common ways of determining the water vapor content of a flowing stream. One method is to use a hygrometer, which is an electronic device. Once the moisture content is known, you can calculate at what temperature moisture will condense from the stream. The Bureau of Mines also produces a device to physically determine the temperature at which condensation occurs by chilling a mirror as a gas stream flows over it and noting the temperature at which the water in the stream begins to coat the mirror and cloud the image. Contracts may specify the maximum temperature at which condensation may occur or the maximum concentration of moisture in the stream.

1.13.2 ENERGY CONTENT, BTU (kJ)

The energy content, Btu (kJ), of a stream may determine its relative value. A stream with a high energy content contains significant quantities of hydrocarbon liquids that may be extracted in a natural gas processing plant and ultimately sold as raw or fractionated product at the outlet of a plant. The energy content may be determined by several different devices including calorimeters, therm-titrators, and energy flow meters, or they may be calculated from the composition of the stream determined by a gas chromatograph or even a composition inferred and estimated from the relative density of the stream.

1.13.3 RECOVERABLE HYDROCARBON LIQUIDS (GPM or m^3_{liq}/m^3_{gas})

The quantity of recoverable hydrocarbon liquids that may be extracted from a gas stream often serves as a measure of the quality of that stream. The heavy ends may be determined using compression test car apparatus, charcoal testing, or chromatography. The higher the concentration of heavier hydrocarbons, the higher the quality or value of the stream tends to be.

The compression test car method from A.G.A.-GPA Standard 101-43 compresses the gas stream and then condenses liquids from that stream in an ice water bath or temperature-controlled chamber at 32°F (0°C) to quantify the amount of liquids that can be condensed from a measured volume of the gas stream. From that quantity, it may be estimated what amount of liquids can be extracted from the gas stream. By considering the volume of gas available as well as the amount of hydrocarbon liquids theoretically recoverable, the amount of hydrocarbon liquids and the volume of residue gas that should be attributed to each individual producing location in an allocation metering system can be directly calculated.

The charcoal test method from A.G.A.-GPA Standard 101-43 uses activated charcoal to absorb heavier hydrocarbons in a gas stream. Once the charcoal sample is returned to a laboratory and heated to drive out the hydrocarbon liquids which are then condensed, they may be measured and compared to the volume of gas that was passed through the filter. The result may be used to determine the relative quality or richness of the stream. Charcoal tests tend to be used on relatively lean streams, and compression test cars are usually used on the relatively rich streams.

Chromatography is another method of determining the recoverable hydrocarbon liquid content in a gas stream. By knowing the approximate percentages of each component that may be recovered from the stream by the natural gas processing facility, and by knowing the quantity and the composition of the gas streams being fed into the facility from each individual producing location, it is possible to calculate the quantity of liquids and the remaining residue gas from each producing location.

1.13.4 COMPOSITION

The composition of a stream from a gas chromatographic analysis may be used in many different ways to characterize the relative quality of a produced stream. By knowing the composition of the stream, either from spot or composite samples, or even semiannual tests, the energy content, the recoverable hydrocarbon liquid content, the percentage of inert gases, and other characteristics may be used to determine the relative quality of the produced stream.

1.14 Gas Calibration and Proving Techniques

1.14.1 ON-SITE CALIBRATIONS

1.14.1.1 Differential Meters (Orifice)

Differential meters (orifice) are composed of a primary device and a secondary device. These meters must first be verified that they meet the design criteria listed in API MPMS Chapter 14.3, Part 2 (ANSI/API 2530 and A.G.A. Report No. 3).

The following must be carefully checked before the system is used:

a. Correct meter tube lengths.
b. Proper straightening vane placement, if required.
c. Correct meter tube tolerances.
d. Suitable range for intended use.
e. Proper chart speed for application.

1.14.1.2 Calibration and Inspection Equipment

1.14.1.2.1 General

a. All calibration equipment must be traceable to a National Institute of Standards and Technology (NIST) standard. Calibration equipment should be certified at least every two years against a NIST traceable standard. Proper certification must be documented. Equipment should be checked throughout the period of use by referencing other certified test equipment.

b. All calibration equipment must meet or exceed the accuracy of the equipment to be calibrated.

c. The required test equipment includes the following:

1. A differential pressure tester.
2. A static pressure tester.
3. A temperature tester.

d. The orifice plate should be inspected, and all of the design criteria of API MPMS Chapter 14.3, Part 2, must be met.

e. The plate should be measured to ensure the recorded bore size is correct. A good quality steel rule is required to check the plate for flatness. The edge of the steel ruler should be placed across the plate in at least three different planes. If light can be seen between the ruler and plate, the plate may be bad. The amount of deviation can be checked with a feeler gauge, using the procedure described in API MPMS Chapter 14.3.

f. It must be assured that the bore is centered. The edge sharpness of the plate should be checked, and the bore should be checked for nicks and scratches. Plates with nicks or scratches should not be used.

g. A bore size should be used that will maintain the differential pressure reading between 20 percent and 80 percent on the chart. The beta ratio should be limited between 0.10 to 0.75 for flange taps.

h. The preferred seal for orifice fittings is the synthetic rubber type of seal. It should be in good physical condition. Document the condition of the seal and note any damage on forms used for accounting.

i. All secondary devices must be calibrated or have their calibrations verified to the manufacturer's specifications.

1.14.1.2.2 Differential Pressure Recorder

Flowing conditions (as found) should be documented before any adjustments are made. All of the following should be checked:

a. Zero at equalized operating pressure.
b. Zero at atmospheric pressure.
c. Arc (if a mechanical recorder is used).
d. For mechanical recorders, five points up and four points down the scale.
e. For electronic flow measurement, three points up and two points down.
f. The flowing differential pressure (only if an error was detected at zero under equalized operating pressure).
g. Chart time and chart drop (only if a mechanical recorder is utilized).

All checks and findings should be documented.

1.14.1.2.3 Static Pressure Recorder

All of the following should be checked:

a. Static pressure at flowing conditions.
b. Static pressure at atmospheric pressure.
c. A minimum of one other point in the normal operating range.
d. Chart time and chart drop time (if appropriate).
e. Three points up and two points down the scale.

All checks and findings should be documented.

1.14.1.2.4 Temperature Recorder

All of the following should be checked:

a. Temperature at flowing conditions.
b. Temperature at ambient conditions.
c. Chart speed and chart drop time (if mechanical recorder is used).

All checks and findings should be documented.

1.14.1.2.5 Leak Detection

The gauge lines, valves, and fittings of all recorders should be tested for leaks, since such leaks can adversely affect the accuracy. This can be accomplished with the use of a soap solution or by blocking in the differential and static pressures and observing the recording pens or by both.

1.14.1.3 Proving Primary Devices (Linear Meters)

1.14.1.3.1 Series Meter Testing

A reference meter checked against a standard shall be installed in series with the meter to be proved. The reference meter should be tested at approximately the same Reynolds number if the test fluid is different, that is, air test.

The proving should consist of measuring the same volume through both meters. The volumes should be corrected for temperature and pressure if differences are present. A minimum of three runs should be made at a given set of flowing conditions.

Meters subject to product conditions that could alter accuracy should be removed from the system for inspection. This may require both visual and physical (spin-test) inspections.

1.14.1.3.2 Electronic End Device Calibration

All electronic end devices that are part of the system shall be calibrated with equipment verified or referenced to NIST standards. These calibration checks shall use sufficient points to assure the accuracy of the range of intended use. Any calibration discrepancies found should be documented. Inspection of these devices should not exceed six month intervals. The flow rate and/or composition shall dictate the optimum frequency of testing.

1.14.2 OFF-SITE CALIBRATIONS

1.14.2.1 Differential Meters (Orifice)

The primary devices for differential meters should not be calibrated off-site.

1.14.2.2 Linear Meters

a. Primary devices should be proved against a reference device that is traceable to a NIST standard or against a NIST standard. The reference meter should be tested at approximately the same Reynolds number if the fluid is different, that is, air test.

b. Enough meter factors should be established to project a meter factor curve.

c. Secondary devices should be verified to a reference device that is traceable to a NIST standard.

1.15 Gas Allocation Calculation Procedures

1.15.1 OVERVIEW

Each gas gathering system is in some way unique. Each system will have its own allocation purpose needs. Methods to account for fuel gas, lift gas, flare gas, and the like must be included in the design of an allocation program. Once designed, the gas allocation program should be reviewed by all production, design, operations, and accounting groups for validity.

1.15.2 CALCULATION PROCEDURE

When performing a gas allocation, the user is simply correcting the theoretical volume of gas or energy at the well site to a known volume of gas or energy sold. This exercise is necessary whenever one gas stream is commingled with another. This is done by prorating the theoretical amounts of gas available for sales to the actual sales amounts. The allocation is performed correctly when this simple math is applied to each stream in a system.

Most regulatory agencies require that *total gas produced* be determined on a periodic basis. It is helpful to calculate this number and report it on all allocations. Once this number is adjusted for any fuel gas, flare gas, lift gas, and other such gases, an available sales volume can be obtained. Allocation calculations should account for 100 percent of sales and shrinkage. This can be done on a volume basis, on an energy content basis, and by test car GPM. The last step is to prorate each volume to actual field or system sales.

1.15.3 OTHER VARIABLES

As stated earlier, most gathering systems or fields exhibit different operating conditions and fluid physical properties. Phase change in the systems, if any, should be taken into account. This can be done physically or be based on experimental and calculated properties as agreed to by the various interests.

When selling various products derived from natural gas, it is common to sell these products for different prices. For instance, when an allocation system is designed for a processing facility, one price might be set for propane and another for methane. Under these circumstances, it is necessary to allocate using the above mentioned procedures for each component in each gas stream.

The individual gas contracts will often dictate allocation procedures. These contracts must be reviewed before designing any allocation program.

1.15.4 AUDITING

The primary purpose of the audit trail is to allow an auditor to know how values were determined and exactly how and why any alterations to original data or calculations were performed. All allocations should be designed with clear audit paths. Current factors should be calculated and compared to historical data. Doing this is a great help in identifying measurement or laboratory differences on a timely basis. Each allocating program should be audited either internally or externally on at least a yearly basis. Again, most gas contracts address this issue and should be reviewed by the allocator.

1.16 Multiphase Quantity Measurement

1.16.1 FLOW MEASUREMENT SYSTEMS

These metering systems indicate a raw composite volume that may be mathematically converted into separate volumes for each phase based on factors developed during periodic well tests.

Regardless of whether the primary device is an orifice meter, wedge meter, turbine meter, or some other device, the metering system output will be a raw composite volume that may be used in allocation calculations.

Each phase is measured separately during calibration. Full well stream gravities, liquid and gas gravities, and factors to determine the relationship between gas volumes and liquid volumes to raw composite volume, should be determined periodically.

Care should be exercised to ensure that the factors are developed during periods when the flows are representative of the rates, temperatures, and pressures typically present in the system. Proving conducted at conditions substantially different from the typical conditions in the multiphase metering system may produce increased uncertainties.

Equipment used to determine the rates and properties of the single phase streams in the proving system should be proved or calibrated in accordance with industry recognized guidelines and methods. For example, the A.G.A. gas measurement manual and/or committee reports could be used for gas meter proving. Oil meter proving could be conducted in accordance with API MPMS guidelines. Water meter proving may be performed with any system and method traceable to the National Institute of Standards and Technology (NIST) standards.

Proving of single phase metering devices away from the operating location should be performed with fluids as similar to the fluid being metered as practical.

1.16.2 SAMPLING

At present there are no methods or standards available to obtain a representative sample from a multiphase stream. The gas, liquid hydrocarbons, and water, if any, will have to be separated into a single phase and then separately sampled. After the full well stream is separated into the gas and liquid phases, sampling can be achieved by spot sampling or composite sampling, preferably proportional to flow, as described in 1.6 and 1.12.

1.16.3 PROVING AND CALIBRATION TECHNIQUES AND EQUIPMENT

Currently, no method exists to prove a metering device in multiphase flow directly with clearly defined uncertainty limits. The multiphase stream must be separated into the individual phases that may be proven or calibrated using methods described in 1.8 and 1.14.

In order to verify the measurement of multiphase streams, they may be separated into single phase streams by the use of a three phase separator. The gas, liquid hydrocarbons, and water, if any, are metered for volume calculations.

1.16.3.1 Equipment Considerations

Separators can be portable or stationary and are equipped with gas and liquid meters.

In general, there are two common types of separation equipment that can be employed: field test separators and portable test separators.

1.16.3.2 Field Test Separators

A field test separator with necessary measuring equipment for conducting periodic tests must also be equipped so that any single well can be switched out of the common unit and through the test separator.

Often an operator will find it feasible to install test equipment adjacent to the common unit handling the commingled streams of all of the wells involved. This test unit usually consists of a vertical separator connected to an inlet manifold through which any one of the wells in the system can be switched for testing. Gas from this separator is passed through a separate dry gas meter run, measured, and returned to the system downstream of the common unit. The condensate collected in the test separator is also measured and returned to the commingled condensate production. Measurement of the condensate can be made by employing either a positive displacement meter, turbine meter, positive volume chamber, or by observing the time required to fill up a previously calibrated section of the vessel. These four procedures will reflect the volume of condensate produced under separator conditions of pressure and temperature. The latter procedure, however, is not always practical since a steady well flow is required to produce comparable fill-up time checks.

The length of the test is determined by the behavior of the well. Consistency of flow can be determined by frequent checks of the yields during the course of the test. This information should be recorded in the field data as evidence. Two to four hours is usually sufficient time to obtain a good test where well flow is consistent. Often a short test is desirable because of the effect of atmospheric temperature changes on the test equipment. Where the well flow is subject to slugging due to low flow rate or interference of water or other causes, it is advisable to extend the test over a longer period of time to ensure better results—possibly twenty-four hours.

Where no separator liquid measurement equipment is available, a test stock tank can be used to measure the condensate produced. To obtain the separator condensate yield during the test period, divide the stock tank volume by the shrinkage factor. The shrinkage factor is often referred to as the *flash factor* and represents the percentage volume change resulting from the lighter hydrocarbons flashing off as temperature and pressure change from separator conditions to stock tank conditions.

Samples of the condensate and gas can be withdrawn for analysis and further study.

1.16.3.3 Portable Test Separators

The portable full-scale test unit usually consists of a two or three-phase field separator mounted on a mobile trailer along with necessary back pressure and measuring equipment for the liquids and the gas. The unit is tied into the flow line downstream of the full well stream meter run by means of a manifold. This manifold consists of a block and bleed valve placed in between inlet and outlet valves through which the entire well flow can be diverted to pass through the test unit and return to the flow line. Short lengths of steel pipe joined with swivel connections or reinforced rubber hose lines are usually used for this purpose. The size and pressure rating of these lines are determined by the type of flow to be handled.

This type of test separator is usually designed so that any free water occurring in the stream can be collected and measured separately. Meanwhile, the condensate is collected and measured by one of the methods previously mentioned and ultimately returned to the gathering system through the return connection of the manifold. The separator gas is likewise diverted through proper measuring equipment before rejoining the measured liquids returning to the gathering system.

During the course of the test, readings of the pressure, temperature, and volumes of both the gas and liquid should be observed and recorded at regular intervals. Quick calculations of the yields at these intervals will serve to indicate the consistency of the flow and aid in determining the proper length of time to be given to the test.

Samples of the condensate and gas can be withdrawn for analysis and further study.

Both of the above types of equipment are intended to serve the same purpose, the choice being determined by their availability and the adaptability to the behavior of the individual well.

In any case, it is necessary that facilities be provided to measure the full well stream volume that each individual well produces daily. Measuring the full well stream is often difficult because of the interference caused by free fluids collecting in the meter run and passing through the orifice plate causing erroneous orifice meter differential readings. The test data will provide a means of correcting for this error.

1.16.4 MULTIPHASE SAMPLE CALCULATION PROCEDURES

Liquid and gas samples are recombined mathematically based on analytical and gas-oil ratio data as determined in the field. The condensate yield of a gas well stream is usually expressed in gallons per thousand standard cubic feet (GPM), barrels per million standard cubic feet (bbl/mmscf), or gas-oil ratio. These terms indicate the relationship between the volume of condensate produced and the volume of separator gas produced at standard conditions.

The volume data and analytical data collected are compiled to perform a full well stream recombination. The data results are then used to calculate the volumes for allocation purposes.

It is often feasible to install a gathering system to collect the total effluent from two or more wells and deliver the commingled stream into a common separator unit. This cuts installation and maintenance costs and permits use of more efficient separation equipment at the central location. The daily production and deliveries of fluids and gas to the purchasers are then reported in a single set of records, thus allowing the field personnel more time to attend the operating phase.

In many instances, a more ideal situation is a conveniently located processing plant that can take the total production for such a group of wells. This gives the producer an opportunity to participate in the revenue derived from the manufacture and sale of certain additional products not ordinarily recovered by normal field separation.

An equitable distribution of the products in the stream of each well contributing to the gathering system must be accomplished. When there is no separation equipment used at the location, the amount of the stock tank fluid produced by a single well cannot be determined. State and federal regulatory agencies require that accurate records of the volumes of both gases and liquids produced by each well be kept. Information is also necessary to settle questions of mineral ownership, proration, legal positions, taxes, and to provide data for continuous reservoir evaluation.

Some form of tests must be performed at regular intervals to determine both the quantity and the quality of the effluent from each individual well. The frequency of the tests is usually dictated by the terms of the contract between the parties involved. Quarterly or semiannual tests are most common. Although in some special cases, monthly tests are conducted when economics or frequent changes in well behavior are suspected.

1.16.5 REPORT CONSIDERATIONS

Good reporting should accompany good testing. Field data are usually a collection of cryptic but complete notes that are used to develop the full-scale separator test report. When the data are gathered for this report, samples of the gases and liquids should be taken for component analysis needed to complete the full well stream recombination report.

A copy of the field notes usually accompanies the report. These field notes contain all of the details of the volume calculations, time and length of the test, and other pertinent data.

1.16.5.1 Full-Scale Separator Test Report

The sample report form in Appendix J shows the information included in a typical report of a full-scale separator test. The same type of report should cover tests made by either the portable or field installed test equipment.

The heading indicates the operator's name and address, well identification, field designation, location, and date of test. The full well stream gas volume based on readings taken from the field master wet gas meter is also shown prominently in the heading.

1.16.5.2 Full Well Stream Recombination Report

The sample full well stream recombination report form in Appendix K contains most of the basic information in the full-scale separator test report as well as the laboratory analysis and test results of the separator effluent under indicated conditions of pressure and temperature.

1.16.5.3 Discussion of Report Sections

The following constitute some of the sections found in the full-scale separator test report and the full well stream recombination report:

1.16.5.3.1 Separator Gas Volume, MCF/Day ($10^3/m^3/day$)

This section represents the actual flow rate of gas from the test separator, the calculation of which includes all of the gas law and supercompressibility corrections in accordance with the contractual agreement. In this instance, the flow rate is further corrected to comply with the applicable pressure base.

1.16.5.3.2 Separator Condensate, GPM or Bbl/MMSCF (m^3_{liq}/m^3_{gas})

This section shows the ratio of the condensate volume produced under separator conditions to the separator gas volume produced during the same period. This is a basic value from which all of the yield data in the report are derived. Therefore, care must be taken by the person conducting the test to assure accurate measurement of the separator effluent. An error at this point would be carried through the balance of the report.

1.16.5.3.3 Analysis of Separator Effluent

A separate section provides a breakdown of the mol percentage of carbon dioxide, nitrogen, and the hydrocarbons in the separator gas, as well as the mol percentage and liquid volume percentage of the hydrocarbons in the separator liquid. The separator gas analysis includes the GPM of ethane, propane, and each heavier component present in the separator gas itself. This is useful in accounting for the various products available for extraction. The liquid analysis serves the same purpose in this instance as does a part of the full well stream composition. The separator gas specific gravity calculated from the analysis and characteristics of the hexanes plus fraction of the separator condensate are also shown.

1.16.5.3.4 Separator Water Make, GPM or Bbl/MMSCF (m^3_{liq}/m^3_{gas})

The water yield shown as GPM or Bbl/MMSCF is related to the volume of separator gas produced over the test period.

1.16.5.3.5 Stock Tank Condensate

During the course of the test, a pressure cell of a known volume is filled with condensate drawn from the separator and placed in a bath at a predetermined temperature. At the proper time, this condensate is released either by instant or differential flash and the stabilized liquid is collected and measured in a graduated cylinder. This residual volume divided by the original volume charged to the cell provides the shrinkage or flash factor mentioned earlier. Then the separator condensate yields are multiplied by this factor to obtain the theoretical stock tank yields as related to the volume of separator gas produced over the same period. API gravity is determined by hydrometer, and the color is observed using the same residual liquid in the field. The hydrocarbon liquid sample can also be analyzed for component value and a flash calculation determined for the final report calculations. Whichever method is utilized, each well must be treated in the same manner.

1.16.5.3.6 Composition and Characteristics of Full Well Stream

These data are computed employing the analyses and tests of the separator gas and condensate in conjunction with the gas-liquid ratio obtained from the field test. In other words, the separator effluent are recombined by calculation in the ratio in which they occur under existing test conditions. The information needed to allocate the recoverable products extant in the full well stream is found by analytical determination of the mol percentage of the constituents. The yields of ethane and heavier components expressed in terms of GPM or Bbl/MMSCF are related to the full well stream gas as are the specific gravity and the characteristics of the hexanes plus fraction.

For accounting purposes, such yields are usually calculated on a monthly basis or at whatever interval settlement is made as required by contractual agreement. Other components or combinations of components expressed as finished products can be accounted for in the same manner.

1.16.5.3.7 Yields Based on Full Well Stream

Most of the discussion to this point has been in the area of collecting and computing data for use in accounting for products manufactured from the commingled gas streams. There is also the situation where the commingled streams are delivered to a common unit where the gas and liquid phases are separated.

1.16.5.3.8 Separator Gas: Percent of Full Well Stream

This section represents the portion of the full well stream gas occupied by the measured volume of separator gas produced under a given set of operating conditions. It is computed from data accumulated in the process of calculating the full well stream composition.

Since this percentage of separator gas is computed on the basis of the correctly measured separator gas, it provides a means of establishing the corrected full well stream volume.

1.16.5.3.9 Separator Gas: Stock Tank Condensate and Water

Each individual well stream is usually equipped with metering facilities for measuring the full well stream wet gas. This is the only measurement made of the well effluent before it enters the gathering system where it is commingled with like streams from other wells for delivery to the common separation unit. This measurement provides the only means of allocating the total commingled stock tank production back to the individual well.

Since the yields shown under this item are based on full well stream measurement, the amount of sales gas attributed to this well is computed by multiplying its total corrected full well stream gas volume by the percentage of separator gas. The barrels of stock tank condensate credited to the particular well can be calculated by multiplying the barrels per million standard cubic feet (MMSCF) by the separator gas stream volume for any given period of time. The amount of water which is produced may be calculated by using the previously defined GPM of water and multiplying by the separator gas volume. These values will provide an equitable means by which the net amount of products sold from the central facility can be divided among the participating wells.

1.16.5.3.10 Meter Factor

Reference has been made in several instances throughout this section to the term *corrected full well stream gas volume*. Under proper supervision and maintenance of metering equipment, followed by correct integration of the resulting charts, it could be assumed that no corrections of the volume thus obtained are needed. However, certain elements present interfere with the passage of gas through the orifice meter and produce erroneous readings. This is primarily caused by free fluids (condensate and water) collecting upstream of and passing through the orifice plate.

The full well stream wet gas meter typically indicates a volume higher than the actual volume being produced. To offset this error, one should refer to the accepted measurement of the separator dry gas where no such interferences occur. Having established the percentage of separator gas present in the full well stream, one can simply arrive at a corrected full well stream volume for a given period. The separator gas volume is divided by the percentage of separator gas. The result is applied in making any calculations involving full well stream yields such as those in this section of the report.

Since the above corrected full well stream is related only to the flow rate of the full well stream at the time the test was conducted, a factor should be established to correct for the error inherent in the system affecting the daily measurement during the period between tests. To obtain this factor, the full well stream volume indicated during the test should be calculated using the readings obtained directly from the master wet gas field meter. This is the observed full well stream volume. The correction, referred to as the *meter factor*, is then obtained by dividing the corrected full well stream volume by the observed volume.

APPENDIX A—VOLUME CORRECTION FACTOR FOR THE EFFECT OF TEMPERATURE ON PRODUCED WATER

A.1 Customary Units

The following procedure can be used to compute the volume correction factor of produced water at various temperatures:

$$CTL_w = (\rho_t) / (\rho_{60})$$

Where:

ρ_t = density of produced water at temperature t (°F) in kg/m^3.
ρ_{60} = density of produced water at 60°F in kg/m^3.

If the information required above is not available, then the curve fit procedure given here can be used:

$$\begin{aligned} CTL_w = 1 &- (1.0312\text{E}{-4} + 7.1568\text{E}{-6} \times B) \times (\Delta t) \\ &- (1.2701\text{E}{-6} - 4.4641\text{E}{-8} \times B) \times (\Delta t)^2 \\ &+ (1.2333\text{E}{-9} - 2.2436\text{E}{-11} \times B) \times (\Delta t)^3 \end{aligned}$$

Where:

B = % salinity by weight. If ρ_{60} is known, B can also be calculated using the formula,
B = $(\rho_{60} - 999.0) / 7.2$.
Δt = $t - 60$.
t = water temperature in °F.

This correction is valid for produced water with salinity up to 14 percent by weight and temperatures from 60°F to 280°F (7.2 kg/m^3) = 1% salinity.

A.2 SI Units

When SI units (metric) are used, the following correlation can be used to compute the volume correction factor of produced water at various temperatures:

$$CTL_w = (\rho_t) / (\rho_{15})$$

Where:

ρ_t = density of produced water at temperature t (°C) in kg/m^3.
ρ_{15} = density of produced water at 15°C in kg/m^3.

If the information required above is not available, then the curve fit procedure given here can be used:

$$\begin{aligned} CTL_w = 1 &- (1.8562\text{E}{-4} + 1.2882\text{E}{-5} \times B) \times (\Delta t) \\ &- (4.1151\text{E}{-6} - 1.4464\text{E}{-7} \times B) \times (\Delta t)^2 \\ &+ (7.1926\text{E}{-9} - 1.3085\text{E}{-10} \times B) \times (\Delta t)^3 \end{aligned}$$

Where:

B = % salinity by weight. If ρ_{15} is known, B can also be calculated using the formula,
B = $(\rho_{15} - 999.0) / 7.2$.
Δt = $t - 15$.
t = Water temperature, in °C.

This correction is valid for produced water with salinity up to 14 percent by weight and temperatures from 15°C to 138°C (7.2 kg/m^3 = 1% salinity).

APPENDIX B—SAMPLE CALCULATION FOR PROCEDURE B STATIC SAMPLING–VOLUMETRIC MEASUREMENT (CUSTOMARY UNITS)

This example shows the calculation of an oil and water volume at stock tank conditions from a metered volume of oil/water mixture and a water cut calculated from a sample. See 1.9.5.3.

The equation for computing the theoretical production, net oil volume, in an oil/water emulsion is expressed as the following:

$$\text{Theoretical production} = \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is the following:

$$V_{w,st} = \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m}$$

B.1 Measured Quantities

a. Indicated volume of oil/water = 100 bbl.
b. Water cut at sample temperature and atmospheric pressure ($X_{w,s}$) = 31.04% by volume.
c. Metering temperature = 100°F.
d. Water cut sample temperature = 68°F.

B.2 Known Parameters

a. Crude oil gravity at 60°F = 23.53 °API.
b. Shrinkage factor of crude oil, (SF) = 0.9600.
c. Meter factor of volumetric flow meter, (MF) = 1.0005.
d. Density of produced water at 60°F = 999.20 kg/m^3.

B.3 Computational Procedure

a. Determine volume correction factor of crude oil at metering temperature. Refer to API MPMS Chapter 11.1, Table 6A.

Use 100°F and 23.53 °API
$CTL_{o,m} = 0.9835$

b. Determine volume correction factor of crude oil at sample temperature. Refer to API MPMS Chapter 11.1, Table 6A.

Use 68°F and 23.53 °API
$CTL_{o,s} = 0.9967$

c. Determine volume correction factor of produced water at metering temperature. See Appendix A.

Use 100°F and $\rho_{60} = 999.20$ kg/m^3
$CTL_{w,m} = 0.9939$

d. Determine volume correction factor of produced water at sampling temperature. See Appendix A.

Use 68°F and $\rho_{60} = 999.20$ kg/m^3
$CTL_{w,s} = 0.9991$

e. Correct the water cut determined at sample conditions to metering conditions.

$$X_{w,m} = \frac{X_{w,s} \times (CTL_{w,s} / CTL_{w,m})}{X_{w,s} \times (CTL_{w,s} / CTL_{w,m}) + (1 - X_{w,s}) \times (CTL_{o,s} / (CTL_{o,m} \times SF))}$$

$$= \frac{0.3104 \times (0.9991/0.9939)}{0.3104 \times (0.9991/0.9939) + (1 - 0.3104) \times (0.9967/(0.9835 \times 0.9600))}$$

$= 0.30$ or 30% by volume

Note: It may be acceptable to use the water cut observed at sample conditions directly without conversion to metering conditions. In that case, 31.04% water cut would be used in place of $X_{w,m}$ in the following calculations.

f. Compute theoretical production of the crude oil.

$$\begin{aligned}\text{Theoretical production} &= \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF \\ &= 100 \text{ bbl} \times 1.0005 \times (1 - 0.30) \times 0.9835 \times 0.9600 \\ &= 66.12 \text{ bbl}\end{aligned}$$

g. Compute net volume of produced water at stock tank conditions.

$$\begin{aligned}V_{w,st} &= \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m} \\ &= 100 \text{ bbl} \times 1.0005 \times 0.30 \times 0.9939 \\ &= 29.83 \text{ bbl}\end{aligned}$$

APPENDIX C—SAMPLE CALCULATION FOR PROCEDURE B STATIC SAMPLING–VOLUMETRIC MEASUREMENT (SI UNITS)

This example shows the calculation of an oil and water volume at stock tank conditions from a metered volume of oil/water mixture and a water cut calculated from a sample. See 1.9.5.3.

The equation for computing the theoretical production, net oil volume, in an oil/water emulsion is expressed as the following:

$$\text{Theoretical production} = \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is the following:

$$V_{w,st} = \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m}$$

C.1 Measured Quantities

a. Indicated volume = 15.90 m^3.
b. Water cut at sample temperature and atmospheric pressure ($X_{w,s}$) = 31.04% by volume.
c. Metering temperature = 37.78°C.
d. Water cut sample temperature = 20°C.

C.2 Known Parameters

a. Density of crude oil at 15°C = 911.90 kg/m^3.
b. Density of produced water at 15°C = 999.30 kg/m^3.
c. Shrinkage factor of crude oil (SF) = 0.9600.
d. Meter factor (MF) = 1.0005.

C.3 Computation Procedure

a. Determine volume correction factor of crude oil at metering temperature. Refer to API MPMS Chapter 11.1, Table 54A.

Use 37.78°C and 911.90 kg/m^3
$CTL_{o,m} = 0.9831$

b. Determine volume correction factor of crude oil at sample temperature. Refer to API MPMS Chapter 11.1, Table 54A.

Use 20°C and 911.90 kg/m^3
$CTL_{o,s} = 0.9963$

c. Determine volume correction factor of produced water at metering temperature. See Appendix A.

Use 37.78°C and $\rho_{15} = 999.30\ kg/m^3$
$CTL_{w,m} = 0.9937$

d. Determine volume correction factor of produced water at sampling temperature. See Appendix A.

Use 20°C and $\rho_{15} = 999.30\ kg/m^3$
$CTL_{w,s} = 0.9990$

e. Adjust the water cut determined at sample conditions to meter conditions:

$$X_{w,m} = \frac{X_{w,s} \times (CTL_{w,s} / CTL_{w,m})}{X_{w,s} \times (CTL_{w,s} / CTL_{w,m}) + (1 - X_{w,s}) \times (CTL_{o,s} / (CTL_{o,m} \times SF))}$$

$$= \frac{0.3104 \times (0.9990/0.9937)}{0.3104 \times (0.9990/0.9937) + (1 - 0.3104) \times (0.9963/(0.9831 \times 0.9600))}$$

$$= 0.30 \text{ or } 30\%$$

Note: In some cases it may be acceptable to use the water cut observed at sample conditions without conversion to metering conditions. In those cases the 31.04% water cut would be used in place of $X_{w,m}$ in the following calculations.

f. Compute theoretical production of the crude oil.

$$\begin{aligned} \text{Theoretical production} &= \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF \\ &= 15.90 \text{ m}^3 \times 1.0005 \times (1 - 0.30) \times 0.9831 \times 0.9600 \\ &= 10.51 \text{ m}^3 \end{aligned}$$

g. Compute net volume of produced water at stock tank conditions.

$$\begin{aligned} V_{w,st} &= \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m} \\ &= 15.90 \text{ m}^3 \times 1.0005 \times 0.30 \times 0.9937 \\ &= 4.74 \text{ m}^3 \end{aligned}$$

APPENDIX D—SAMPLE CALCULATION FOR PROCEDURE C DYNAMIC SAMPLING–VOLUMETRIC MEASUREMENT (CUSTOMARY UNITS)

This example shows the calculation of oil and water volume at stock tank conditions from a metered volume of oil/water mixture and a water cut determined by an on-line water cut analyzer. Note that the water cut as measured herein is expressed as the volume fraction of water in the oil/water mixture at metering conditions. See 1.9.5.4.

The equation used to compute theoretical production in an oil/water mixture is expressed as the following:

$$\text{Theoretical production} = \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for net produced water volume is the following:

$$V_{w,st} = \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m}$$

D.1 Measured Quantities

a. Indicated volume = 100 bbl.
b. Metering water cut ($X_{w,m}$) = 30% by volume.
c. Metering temperature = 100°F.
d. Metering pressure = 80 psig.

D.2 Known Parameters

a. Crude oil gravity at 60°F = 30 °API.
b. Shrinkage factor (SF) = 0.9600.
c. Meter factor (MF) = 1.0005.
d. Density of water at 60°F = 999.012 kg/m^3.

D.3 Computation Procedure

a. Determine correction factor for the effect of metering temperature on the crude oil. See API MPMS Chapter 11.1, Table 6A.

Use 100°F and 30 °API
$CTL_{o,m} = 0.9821$

b. Determine correction factor for the effect of metering temperature on the water. See Appendix A.

Use 100°F and 999.012 kg/m^3
$CTL_{w,m} = 0.9939$

c. Compute the theoretical volume of the crude oil.

$$\begin{aligned}\text{Theoretical production} &= \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF \\ &= 100 \text{ bbl} \times 1.0005 \times (1 - 0.30) \times 0.9821 \times 0.9600 \\ &= 66.03 \text{ bbl}\end{aligned}$$

d. Compute net volume of produced water corrected at stock tank conditions.

$$\begin{aligned}X_{w,st} &= \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m} \\ &= 100 \text{ bbl} \times 1.0005 \times 0.30 \times 0.9939 \\ &= 29.83 \text{ bbl}\end{aligned}$$

APPENDIX E—SAMPLE CALCULATION FOR PROCEDURE B DYNAMIC SAMPLING–VOLUMETRIC MEASUREMENT (SI UNITS)

This example shows the calculation of oil and water volume at stock tank conditions from a metered volume of oil/water mixture and a water cut determined by an inline water cut analyzer. Note that the water cut as measured herein is expressed as the volume fraction of water in the oil/water mixture at metering conditions. See 1.9.5.4.

The equation used to compute theoretical production in an oil/water mixture is expressed as the following:

$$\text{Theoretical production} = \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for net produced water volume is the following:

$$V_{w,st} = \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m}$$

E.1 Measured Quantities

a. Indicated volume = 15.90 m^3.
b. Metering water cut ($X_{w,m}$) = 30% by volume.
c. Metering temperature = 37.78°C.
d. Metering pressure = 551.6 kPa.

E.2 Known Parameters

a. Density of crude oil at 15°C = 875.36 kg/m^3.
b. Density of produced water at 15°C = 999.28 kg/m^3.
c. Shrinkage factor (SF) = 0.9600.
d. Meter factor (MF) = 1.0005.

E.3 Computation Procedure

a. Determine correction factor for the effect of metering temperature on the crude oil. Refer to API MPMS Chapter 11.1, Table 54A.

Use 37.78°C and 875.36 kg/m^3
$CTL_{o,m} = 0.9816$

b. Determine correction factor for the effect of metering temperature on the water. See Appendix A.

Use 37.78°C and 999.28 kg/m^3
$CTL_{w,m} = 0.9937$

c. Compute the theoretical volume of the crude oil.

$$\begin{aligned}\text{Theoretical production} &= \text{Indicated volume} \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF \\ &= 15.90\ m^3 \times 1.0005 \times (1 - 0.30) \times 0.9816 \times 0.9600 \\ &= 10.49\ m^3\end{aligned}$$

d. Compute net volume of produced water.

$$\begin{aligned}V_{w,st} &= \text{Indicated volume} \times MF \times X_{w,m} \times CTL_{w,m} \\ &= 15.90\ m^3 \times 1.0005 \times 0.30 \times 0.9937 \\ &= 4.74\ m^3\end{aligned}$$

APPENDIX F—SAMPLE CALCULATION FOR PROCEDURE A DYNAMIC SAMPLING–MASS MEASUREMENT (CUSTOMARY UNITS)

This example shows how to compute net oil volume and net produced water in an oil/water mixture where the water content is measured by the on-line analyzer. See 1.9.10.3.

The equation used to compute net oil volume, in an oil/water mixture is expressed as the following:

$$V_{o,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is the following:

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$

F.1 Measured Quantities

a. Measured mass of oil/water mixture (M_e) = 1000 lbm.
b. Water cut at metering conditions ($X_{w,m}$) = 30% by volume.
c. Metering temperature = 100°F.
d. Metering pressure = 80 psig.

F.2 Known Parameters

a. Crude oil at 60°F ($D_{o,st}$) = 30 °API.
b. Density of produced water at 60°F ($D_{w,st}$) = 999.20 kg/m^3.
c. Shrinkage factor (SF) = 0.9600.
d. Meter factor (MF) = 1.0005.
e. Conversion units factor (C_{uf}) = $2.853 \ \dfrac{\text{kg-bbl}}{\text{lb-m}^3}$.

F.3 Computation Procedure

a. Determine volume correction factor of crude oil at metering temperature. Refer to API MPMS Chapter 11.1, Table 6A.

Use 100°F and 30 °API
$CTL_{o,m} = 0.9821$

b. Determine density of crude oil at 60°F.

Convert °API to density

$$D_{o,st} = \frac{141.5 \times 999.012}{30 + 131.5}$$
$$= 875.30 \text{ kg/m}^3$$

c. Determine density of crude oil at metering temperature.

$$D_{o,m} = D_{o,st} \times CTL_{o,m}$$
$$= 875.30 \text{ kg/m}^3 \times 0.9821$$
$$= 859.63 \text{ kg/m}^3$$

d. Determine volume correction factor of produced water at metering temperature. See Appendix A.

Use 100°F and $\rho_{60} = 999.20$ kg/m^3
$CTL_{w,m} = 0.9939$

e. Determine density of produced water at metering temperature.

$$D_{w,m} = D_{w,st} \times CTL_{w,m}$$
$$= 999.20 \text{ kg/m}^3 \times 0.9939$$
$$= 993.10 \text{ kg/m}^3$$

f. Compute density of oil/water emulsion at metering condition.

$$
\begin{aligned}
D_{e,m} &= D_{o,m} \times (1 - X_{w,m}) + D_{w,m} \times X_{w,m} \\
&= 859.63 \text{ kg/m}^3 \times (1 - 0.30) + 993.10 \text{ kg/m}^3 \times 0.30 \\
&= 899.67 \text{ kg/m}^3
\end{aligned}
$$

Note: In many cases the density of the oil/water emulsion at metering conditions is directly available as an output from the mass meter. If water cut has been determined by static methods, that is sampling and analysis at atmospheric conditions, instead of the dynamic method as in this example, $X_{w,m}$ will have to be computed from the water cut at sampling conditions.

g. Compute the net volume of the crude oil.

$$
\begin{aligned}
V_{o,st} &= C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF \\
&= 2.853 \times (1000/899.67) \times 1.0005 \times (1 - 0.30) \times 0.9821 \times 0.9600 \\
&= 2.09 \text{ bbl}
\end{aligned}
$$

h. Compute the net volume of produced water.

$$
\begin{aligned}
V_{w,st} &= C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_w \\
&= 2.853 \times (1000/899.67) \times 1.0005 \times 0.30 \times 0.9939 \\
&= 0.95 \text{ bbl}
\end{aligned}
$$

APPENDIX G—SAMPLE CALCULATION FOR PROCEDURE A DYNAMIC SAMPLING–MASS MEASUREMENT (SI UNITS)

This example shows how to compute net oil volume and net produced water in an oil/water mixture where the water content is measured by the on-line analyzer. See 1.9.10.3.

The equation for computing the net oil volume in an oil/water emulsion is expressed as the following:

$$V_{o,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is the following:

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$

G.1 Measured Quantities

a. Measured mass of oil/water mixture (M_e) = 453.6 kg.
b. Water cut at metering conditions ($X_{w,m}$) = 30% by volume.
c. Metering temperature = 37.78°C.
d. Metering pressure = 551.6 kPa.

G.2 Known Parameters

a. Density of crude oil at 15°C ($D_{o,st}$) = 875.36 kg/m^3.
b. Density of produced water at 15°C ($D_{w,st}$) = 999.28 kg/m^3.
c. Shrinkage factor (SF) = 0.9600.
d. Meter factor (MF) = 1.0005.
e. Conversion units factor (C_{uf}) = 1.0000.

Note: In some cases the small error incurred by using the crude oil gravity at atmospheric pressure rather than metering pressure may be acceptable because of the difficulty in obtaining the latter.

G.3 Computation Procedure

a. Determine volume correction factor of crude oil at metering temperature. Refer to API MPMS Chapter 11.1, Table 54A.

Use 37.78°C and 875.36 kg/m^3
$CTL_{o,m} = 0.9816$

b. Determine density of crude oil at metering temperature.

$$\begin{aligned} D_{o,m} &= D_{o,st} \times CTL_{o,m} \\ &= 875.36 \text{ kg/m}^3 \times 0.9816 \\ &= 859.25 \text{ kg/m}^3 \end{aligned}$$

c. Determine volume correction factor of produced water at metering temperature. See Appendix A.

Use 37.78°C and 999.28 kg/m^3
$CTL_{w,m} = 0.9937$

d. Determine density of produced water at metering temperature.

$$\begin{aligned} D_{w,m} &= D_{w,st} \times CTL_{w,m} \\ &= 999.28 \text{ kg/m}^3 \times 0.9937 \\ &= 992.98 \text{ kg/m}^3 \end{aligned}$$

e. Compute density of oil/water emulsion at metering condition.

$$\begin{aligned}D_{e,m} &= D_{o,m} \times (1 - X_{w,m}) + D_{w,m} \times X_{w,m}\\ &= 859.25 \text{ kg/m}^3 \times (1 - 0.30) + 992.98 \text{ kg/m}^3 \times 0.30\\ &= 899.37 \text{ kg/m}^3\end{aligned}$$

Note: In many cases the density of the oil/water emulsion at metering conditions is directly available as an output of the mass meter. If water cut has been determined by static methods, that is sampling and analysis at atmospheric conditions, instead of the dynamic method as in this example, $X_{w,m}$ will have to be computed from the water cut at sampling conditions.

f. Compute net volume of the crude oil.

$$\begin{aligned}V_{o,st} &= C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF\\ &= 1.00 \times (453.6/899.37) \times 1.0005 \times (1 - 0.30) \times 0.9816 \times 0.9600\\ &= 0.33 \text{ m}^3\end{aligned}$$

g. Compute net volume of produced water.

$$\begin{aligned}V_{w,st} &= C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_w\\ &= 1.00 \times (453.6/899.37) \times 1.0005 \times 0.30 \times 0.9937\\ &= 0.15 \text{ m}^3\end{aligned}$$

APPENDIX H—SAMPLE CALCULATION FOR PROCEDURE B STATIC SAMPLING–MASS MEASUREMENT (CUSTOMARY UNITS)

This example shows how to compute net oil volume in an oil/water mixture where the water content sample is obtained by using a proportional sampling technique or a grab sampling technique. The sample is exposed to atmospheric pressure and the water content of the sample is determined by laboratory or field methods. See 1.9.10.4.

The equation for computing the net oil volume in an oil/water emulsion is expressed as the following:

$$V_{o,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is the following:

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$

H.1 Measured Quantities

a. Measured mass of oil/water mixture, $(M_e) = 1000$ lbm.
b. Water content measured $(X_{w,s}) = 31.12\%$ by volume.
c. Metering temperature = 100°F.
d. Metering pressure = 80 psig.
e. Sampling temperature = 75°F.
f. Crude oil gravity at 60°F = 23.53 °API.
g. Density of emulsion at 60°F $(D_{e,m}) = 912.93$ kg/m^3.
(from Coriolis meter)

H.2 Known Parameters

a. Crude oil density at 15°C $(D_{o,st}) = 912.20$ kg/m^3.
b. Density of produced water $(D_{w,st})$ at 60°F = 999.20 kg/m^3.
c. Shrinkage factor $(SF) = 0.9600$.
d. Meter factor $(MF) = 1.0005$.
e. Conversion units factor = $2.853 \dfrac{\text{kg-bbl}}{\text{lb-m}^3}$.

H.3 Computational Procedure

a. Adjust water cut to metering pressure. (Use Table 6A or ASTM D1250 Table 3 and Appendix A.)

Use 75°F and 999.20 kg/m^3
$CTL_{w,s} = 0.9982$

Use 75°F and 23.53 °API
$CTL_{o,s} = 0.9938$

Use 100°F and 999.20 kg/m^3
$CTL_{w,m} = 0.9939$

Use 100°F and 23.53 °API
$CTL_{o,m} = 0.9835$

$$X_{w,m} = \frac{X_{w,s} \times (CTL_{w,s}/CTL_{w,m})}{X_{w,s} \times (CTL_{w,s}/CTL_{w,m}) + (1 - X_{w,s}) \times (CTL_{o,s}/(CTL_{o,m} \times SF))}$$

$$= \frac{0.3112 \times (0.9982/0.9939)}{0.3112 \times (0.9982/0.9939) + (1 - 0.3112) \times (0.9938/(0.9835 \times 0.9600))}$$

$$= 0.3012 \text{ or } 30.12\%$$

b. Compute net volume of the crude oil.

$$V_{o,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times SF \times CTL_{o,m}$$
$$= 2.853 \times (1000/912.93) \times 1.0005 \times (1 - 0.3012) \times 0.9835 \times 0.9600$$
$$= 2.06 \text{ bbl}$$

c. Compute net volume of produced water.

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$
$$= 2.853 \times (1000/912.93) \times 1.0005 \times 0.3012 \times 0.9939$$
$$= 0.94 \text{ bbl}$$

APPENDIX I—SAMPLE CALCULATION FOR PROCEDURE B STATIC SAMPLING–MASS MEASUREMENT (SI UNITS)

This example shows how to compute net oil volume in an oil/water mixture where the water content sample is obtained by using a proportional sampling technique or a grab sampling technique. The sample is exposed to atmospheric pressure, and the water content of the sample is determined by laboratory or field methods. See 1.9.10.4.

The equation for computing the net oil volume in an oil/water emulsion is expressed as the following:

$$V_{o,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times (1 - X_{w,m}) \times CTL_{o,m} \times SF$$

The equation for computing net produced water volume is the folowing:

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$

I.1 Measured Quantities

a. Measured mass oil/water mixture (M_e) = 453.6 kg.
b. Water content ($X_{w,s}$) = 31.12% by volume.
c. Metering temperature = 37.78°C.
d. Sampling temperature = 23.89°C.
e. Metering pressure = 551.6 kPa.
f. Density of emulsion ($D_{e,m}$) = 912.94 kg/m^3.

I.2 Known Parameters

a. Crude oil density at 15°C ($D_{o,st}$) = 912.20 kg/m^3.
b. Density of produced water at 15°C ($D_{w,st}$) = 999.28 kg/m^3.
c. Shrinkage factor (SF) = 0.9600.
d. Meter factor (MF) = 1.0005.
e. Conversion units factor = 1.000.

I.3 Computational Procedure

a. Adjust water cut to metering pressure. (Use Table 54A and Appendix A for temperature volume corrections.)

Use 23.89°C and 999.28 kg/m^3 $CTL_{w,s} = 0.9980$	Use 23.89°C and 912.2 kg/m^3 $CTL_{o,s} = 0.9933$
Use 37.78°C and 999.28 kg/m^3 $CTL_{w,m} = 0.9937$	Use 37.78°C and 912.2 kg/m^3 $CTLo,m = 0.9831$

$$X_{w,m} = \frac{X_{w,s} \times (CTL_{w,s}/CTL_{w,m})}{X_{w,s}(CTL_{w,s}/CTL_{w,m}) + (1 - X_{w,s}) \times (CTL_{o,s}/(CTL_{o,m} \times SF))}$$

$$= \frac{0.3112 \times (0.9980/0.9937)}{0.3112 \times (0.9980/0.9937) + (1 - 0.3112) \times (0.9933/(0.9831 \times 0.9600))}$$

$$= 0.3013 \text{ or } 30.13\%$$

b. Compute net volume of the crude oil.

$V_{o,st} = C_{uf}(M_e/D_{e,m}) \times (1 - X_{w,m}) \times MF \times SF \times CTL_{o,m}$
$= 1.000 \times (453.6 \text{ kg}/912.94 \text{ kg/m}^3) \times (1 - 0.3013) \times 1.0005 \times 0.9600 \times 0.9831$
$= 0.33 \text{ m}^3$

c. Compute net volume of produced water.

$$V_{w,st} = C_{uf} \times (M_e/D_{e,m}) \times MF \times X_{w,m} \times CTL_{w,m}$$
$$= 1.000 \times (453.6\ \text{kg}/912.94\ \text{kg/m}^3) \times 1.0005 \times 0.3013 \times 0.9937$$
$$= 0.15\ \text{m}^3$$

APPENDIX J—FULL SCALE FIELD SEPARATOR TESTING SAMPLE REPORT FORM

Date October 30 19 91

COMPANY Your Company U.S.A.	FIELD Some, Texas ZONE TP
WELL NAME Any Well #1	COUNTY Some, Texas
STATION #	STATION # 555-555
Well Head Pressure Flowing 490 PSIG @ 125 °F	Shut-In PSIG @ °F After Hours

A. GAS VOLUMES @ 14.65 PSIG @ 60°F			**B. SEPARATOR YIELDS**
	WELL MASTER METER	SEPARATOR GAS METER	Length of Test 17.50 Hours
Size Meter and Orifice	2.900 x 1.000	3.068 x 1.000	Start: 2:00 AM / [✓ PM]
Specific Gravity Gas	0.689	0.665	Stop: 7:30 [✓ AM] / PM
Orifice Coefficient	204.04 x 24	203.54 x 24	
	L-10 / [✓ Direct]	L-10 / [✓ Direct]	Test Unit # 7
Range Pressure	2000	1500	
Range Diff.	100	100	One PV Unit = 11.7 Gallons
Average Readings	PSIG DIFF. °F	PSIG DIFF. °F	
	460 62 141	450 58,9 120	Condensate Make / Test
[✓ Ext.] / M.F.	171.55	164.16	19 PV Units + 7 Gallons
Gravity Factor	1.2047	1.2263	229.3 Gallons @ 57 °F
Press. Base Factor	1.0055	1.0055	
Temp. Factor	0.9302	0.9469	
Deviation Factor	1.0296	1.0306	Water Make / Test
Daily Coeff. C.F.	5680.9	5878.0	3.0 Gallons
Net Gas. MCF / Day	975	965	

VOLUME CORRECTION FACTOR 0.9957

C. CONDENSATE SHRINKAGE	**D. SEPARATOR CONDENSATE YIELD**
Differential / Instant Flash	Temperature Corr. Factor 1.0017
Initial Vol. 314 ML @ 447 PSIG @ 57 °F	Liquid Meter Factor 1.0000
Temp. Corr. Factor 1.0017	Net Separator Condensate @ 60 °F =
Final Vol. 283 ML @ Atmosphere @ 63 °F	229.3 x 1.0017 x 24/17.50
Temp. Corr. Factor 0.99831	315.0 Gallons / Day or 7.50 Barrels / Day
Shrink Factor 0.898	GPM 0.326 Barrels / MM 7.76
E. STOCK TANK YIELDS	**F. WATER MAKE**
Liquid Volume @ 60 °F	Chloride 98600 ppm
API 50.5 Color Lt. Straw	Gallons / Day 3.00 x 24/17.50 = 4.10
315.0 x 0.898 = 282.90 Gallons / Day	Barrels / Day 0.10
Barrels / Day 6.74	GPM 0.004 BBLS / MM 0.10
GPM 0.293 BBLS / MM 6.98	
GOR 143175:1	By:
Gathering System:	
Remarks:	

APPENDIX J—FULL SCALE FIELD SEPARATOR TESTING SAMPLE SUMMARY FORM

Company:	Your Company USA		
Well Name:	Any Well #1		
Station No.:	555-5555		
Field:	(TP) Some, Texas	**County:**	Some, Texas
Date of Test:	10/30/91	**Length of Test:**	17.50 Hours
Tested By:	Employee #42	**Vol. Corr. Factor:**	0.99572
FTP:	490 PSIG		
Remarks:			

Master Meter:			**Separator Meter:**		
2.900 x 1.0000			3.068 x 1.0000		
460 PSIG	62.00 In.	141 Deg F	450 PSIG	58.00 In.	120 Deg F
Type Chart:	Direct		Type Chart:	Direct	

A. Full Well Stream Gas Measurements:

M.M. Vol. MCF / Day	975
Full Well Stream Gravity	0.689

B. Yields and Tests of Separator Effluents:

1.	Separator Gas Volume	MCF / Day	965
	Separator Gas Gravity	@ 60 Deg F (Air = 1)	0.665
2.	Separator Condensate	GPM	0.326
		BBL / MM	7.76
		Gal / Day	315.00
		BBL / Day	7.50
3.	Separator Water	GPM	0.004
		BBL / MM	0.10
		BBL / Day	0.10
		Chloride Content	98600
4.	Stock Tank Condensate	GPM	0.293
		BBLS / MM	6.98
		BBLS / Day	6.74
		Gas-Oil Ratio	143175:1
5.	Tests	API Gravity @ 60 Deg F	50.5
		Color	Lt. Straw
6.	Liquid Shrink Factor, percent		89.8

C. Yields Based on Full Well Stream Volume:

1.	Separator Gas, percent		99.40
2.	Stock Tank Condensate	GPM	0.291
		BBLS / MM	6.93

Note: Yields Based on Gas Measured @ 14.6500 PSIA @ 60 Deg F

APPENDIX K—FULL WELL STREAM RECOMBINATION REPORT

	Certificate of Analysis No.
Company:	Your Company USA
Location:	Any Well #1
Field:	Some, Texas
Sample of:	Full Scale Sep. Gas and Liquid
Conditions:	450 PSIG at 120 Deg F
Sampled By:	Employee #42
Sample Date:	10/30/91

For: Your Company USA
555 Texas Avenue November 8, 1991
Some City, Texas 55555-5555

A. Separator Effluents:	Separator Gas		Separator Liquid		
	MOL%	GPM	MOL%	LIQ VOL%	WT%
Nitrogen	0.22				
Carbon dioxide	0.65				
Methane	87.37		11.94	3.74	1.50
Ethane	6.44	1.713	4.26	2.10	1.00
Propane	2.93	0.803	5.40	2.75	1.87
Iso-butane	0.52	0.169	2.54	1.53	1.16
N-butane	0.92	0.288	3.24	1.89	1.48
Iso-pentane	0.26	0.095	1.91	1.29	1.08
N-pentane	0.29	0.104	2.48	1.66	1.40
Hexanes	0.17	0.070	4.51	3.43	3.05
Heptanes plus	0.23	0.111	63.72	81.61	87.46
	100.00	3.353	100.00	100.00	100.00

1. Specific gravity separator gas @ 60 Deg F (air = 1) 0.6653

   Separator gas BTU @ 14.650 PSIA @ 60 Deg F

   Dry . . . . . 1160 Wet 1140

2. Heptanes plus in separator liquid:

Specific gravity @ 60 Deg F (water = 1)	0.7994
Molecular weight	175.00
Cubic feet vapor per gallon @ 14.650 PSIA @ 60 Deg F	14.50
Specific gravity as a vapor (air = 1)	7.2015

3. Total Liquid Sample:

Liquid specific gravity @ 60 Deg F (water = 1)	0.7460
Cubic feet vapor per gallon @ 14.650 PSIA @ 60 Deg F	18.57
Cubic feet vapor per barrel @ 14.650 PSIA @ 60 Deg F	779.94
Specific gravity as a vapor (Air = 1)	5.1410

APPENDIX K—Continued

B. Separator Yields:		
1. Separator Gas Volume	MCF / Day	965
2. Separator Condensate	GPM	0.326
	BBL / MM	7.76
	BBL / Day	7.50
	Gas-Oil Ratio	128667:1
3. Separator Water Make	GPM	0.004
	BBL / MM	0.10
	BBL / Day	0.10

C. Stock Tank Yields:		
	Shrinkage Factor	0.8980
	GPM	0.293
	BBL / MM	6.98
	BBL / Day	6.74
	Gas-Oil Ratio	143281:1
Tests	API gravity @ 60 Deg F	50.5
	Color	Lt. Straw

D. Composition and Characteristics of Full Well Stream:

	MOL%	GPM	BBL / MM
Nitrogen	0.22		
Carbon dioxide	0.65		
Methane	86.92		
Ethane	6.43	1.710	40.714
Propane	2.94	0.806	19.190
Iso-butane	0.53	0.172	4.095
N-butane	0.93	0.292	6.952
Iso-pentane	0.27	0.098	2.333
N-pentane	0.30	0.108	2.571
Hexanes	0.20	0.082	1.952
Heptanes plus	0.61	0.368	8.762
	100.00	3.636	86.569

Heptanes plus in Full Well Stream:	
Specific gravity @ 60 Deg F (water = 1)	0.7678
Molecular weight	147.01
Cubic feet vapor per gallon	16.58
Specific gravity full well stream @ 60 Deg F (air = 1)	0.6932

APPENDIX K—Continued

E. Yields Based on Full Well Stream:

1.	Full well stream volume	MCF / Day	975
2.	Separator gas, percent 99.40	Separator gas, cubic feet	994
3.	Separator condensate	GPM	0.324
		BBL / MM	7.73
4.	Separator water make	GPM	0.004
		BBL / MM	0.10
5.	Stock tank condensate	GPM	0.291
		BBL / MM	6.94

F. Meter Factor:

Actual volume = sep. gas vol. / % sep. gas 0.971

Factor = actual volume / full well str. vol. 0.9957

Note: Yields based on gas measured @ 14.650 psia @ 60 Deg F

G. Stock Tank Liquid:

Tests	API gravity @ 60 Deg F	50.5
	Color	Lt. Straw

9/98—XX

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