

Manual of Petroleum Measurement Standards Chapter 20.5

Recommended Practice for Application of Production Well Testing in Measurement and Allocation

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Foreword

This edition of API Manual of *Petroleum Measurement Standards (MPMS)* Chapter 20.5 supersedes the below listed sections of API *MPMS* Chapter 20.1, *Allocation Measurement*, First Edition, 1993:

- 1.7.2.2.2 Test Separator;
- 1.11.1 Well Tests;
- 1.16.3.2 Field Test Separators;
- 1.16.3.3 Portable Test Separators;
- 1.16.5.1 Full-Scale Separator Test Report;
- Appendix J.

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Introduction

This document establishes a framework to conduct and apply production well testing for well rate determination in measurement and allocation. Production well testing addressed in this document refers to measurement of gas, oil, and water quantities from a single well during a specified length of time under controlled operational conditions. The intent of this document is to provide operators with a consistent and transparent approach for conducting, applying, and managing production well testing within an upstream measurement and allocation system. It is not intended to prescribe a particular production well test method, or particular application of production well test data use in allocation. Allocation methodologies are addressed in API *MPMS* Ch. 20.1.

Recommended Practice for Application of Production Well Testing in Measurement and Allocation

1 Scope

This document provides recommendations and guidelines for the application of production well testing in production measurement and allocation. The recommendations and guidelines apply to conducting a production well test, calculating production well test volumes and rates, and the application of production well test data for use in measurement and allocation. This includes production well testing preparation, initiation, measurement, validation, and volume and rate calculations for separator, multiphase flow meter, and tank production well test systems. Additionally, this document addresses the proration of production well test results for use in allocation, the application of production well tests for validation and update of well flow models and virtual flow metering, and the adjustment of gas well continuous measurement results with production well test data.

This document also provides recommendations and guidelines for the application of well flow modeling and virtual flow metering in production measurement and allocation.

2 Normative References

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

API Draft Standard *Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems*

API *Manual of Petroleum Measurement Standards (MPMS)*, Chapter 3.1A, *Standard Practice for the Manual Gauging of Petroleum and Petroleum Products*

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

API MPMS Chapter 3.3, *Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging*

API MPMS Chapter 3.6, *Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems*

API MPMS Chapter 8.1, *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*

API MPMS Chapter 8.2, *Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products*

API MPMS Chapter 11.1, *Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils*

API MPMS Chapter 14.1, *Collecting and Handling of Natural Gas Samples for Custody Transfer*

API MPMS Chapter 18.1, *Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck*

API MPMS Chapter 20.1, *Production Measurement and Allocation Systems*

API MPMS Chapter 20.2, *Production Allocation Measurement Using Single-phase Devices*

API MPMS Chapter 20.3, *Measurement of Multiphase Flow*

API MPMS Chapter 21.1, *Flow Measurement Using Electronic Metering Systems—Electronic Gas Measurement*

API Recommended Practice 85, *Use of Subsea Wet-gas Flowmeters in Allocation Measurement Systems*

API Recommended Practice 87, *Recommended Practice for Field Analysis of Crude Oil Samples Containing from Two to Fifty Percent Water by Volume*

API Recommended Practice 551, *Process Measurement*

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 Terms and Definitions

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

3.1.1

actual conditions

measurement conditions

line conditions

flowing conditions

Conditions of pressure and temperature of the fluid at the point where fluid properties or flows are measured.

3.1.2

allocation

The mathematical process of determining the proportion of produced fluids from individual entities (zones, wells, fields, leases, or producing units) when compared to the total production from the entire system (reservoir, production system, and gathering systems) in order to determine value or ownership to attribute to each entity.

3.1.3

bubble point

When the pressure is lowered on a liquid held at a constant temperature, the pressure at which the first bubble of vapor forms is the bubble point.

3.1.4

condensate–gas ratio

CGR

The ratio of liquid hydrocarbon volume flow rate to the gas volume flow rate at any point, expressed at standard conditions, usually in barrel per thousand standard cubic feet (bbl/mscf) or standard cubic meters of liquid hydrocarbon per thousand cubic meters of gas ($\text{m}^3/10^3\text{m}^3$).

3.1.5

equation of state

EOS

Thermodynamic equation describing the state of matter under a given set of physical conditions.

NOTE An EOS provides a mathematical relationship among the state variables pressure, temperature, and molar volume.

3.1.6

gas–liquid ratio

GLR

The ratio of gas volume flow rate to the total liquid volume flow rate at any point, expressed at standard conditions, usually in standard cubic feet per barrel (scf/bbl) or standard cubic meters of gas per cubic meter of total liquid (m^3/m^3).

3.1.7

gas-oil ratio

GOR

The ratio of gas volume flow rate to the liquid hydrocarbon volume flow rate at any point, expressed at standard conditions, usually in standard cubic feet per barrel (scf/bbl) or standard cubic meters of gas per cubic meter of liquid hydrocarbon (m^3/m^3).

3.1.8

gas volume correction factor

B_g

Ratio of hydrocarbon gas volume at elevated pressure and temperature conditions to the hydrocarbon gas volume at standard conditions (ft^3/scf , m^3/m^3).

3.1.9

gas volume fraction

GVF

The fraction of the total volumetric flow rate at actual conditions in the pipe that is attributable to gas flow, often expressed as a percentage.

3.1.10

hold-up

The cross-sectional area locally occupied by one of the phases of a multiphase flow, relative to the cross-sectional area of the conduit at the same local position, at actual conditions.

3.1.11

hydrocarbon dew point

A temperature at a given pressure at which hydrocarbon vapor condensation begins.

3.1.12

multiphase flow

Flow of a composite fluid that includes natural gas, hydrocarbon liquids, water, and injected fluids, or any combination of these.

3.1.13

nodal analysis

A method to model well multiphase production through an integrated oil and gas production system with multiple points of measurement (nodes). The models are based on fundamental mechanistic physics principles that estimate well production using input pressures and temperatures, and flow correlations.

3.1.14

oil volume correction factor

B_o

Ratio of the hydrocarbon liquid volume at elevated pressure and temperature conditions to the hydrocarbon liquid volume at standard conditions (bbl/bbl, m^3/m^3).

NOTE The oil volume correction factor B_o , is the inverse of the shrinkage correction factor, $1/B_o$.

3.1.15

pressure, volume, temperature

PVT

The phase behavior and description of hydrocarbon fluid physical properties for a given set of composition, pressure, and temperature.

NOTE Physical properties of interest include relative phase fraction, GOR, bubble point and hydrocarbon dew point, density, formation volume factors, compressibility, and viscosity.

3.1.16

production well test

The measurement of gas, oil, and water quantities from a single well during a specified length of time under controlled operational conditions.

3.1.17

rangeability

The capability of a meter or flow measuring device to operate between the minimum and maximum flow range within a specified uncertainty; expressed as the ratio of maximum flow rate to the minimum flow rate.

3.1.18

solution condensate–gas ratio

r_s

Ratio of condensed hydrocarbon liquid volume at standard conditions (condensed from gas as it is lowered in pressure and temperature from elevated pressure and temperature conditions to standard conditions) to the hydrocarbon gas volume at standard conditions (bbl/mscf, $\text{m}^3/10^3\text{m}^3$).

3.1.19

solution gas–oil ratio

R_s

Ratio of evolved hydrocarbon gas volume at standard conditions (evolved from hydrocarbon liquid as it is lowered in pressure and temperature from elevated pressure and temperature conditions to standard conditions) to the hydrocarbon liquid volume at standard conditions (mscf/bbl, $10^3\text{m}^3/\text{m}^3$).

NOTE The evolved hydrocarbon gas is sometimes referred to as flash gas.

3.1.20

virtual flow meter

VFM

Real-time computer-based well rate determination method that utilizes well flow models in conjunction with real-time well/process sensor and instrumentation data for continuous multiphase well rate estimation.

3.1.21

water–gas ratio

WGR

The ratio of water volume flow rate to the gas volume flow rate at any point, expressed at standard conditions, usually in barrel per thousand standard cubic feet (bbl/mscf) or standard cubic meters of liquid hydrocarbon per thousand cubic meters of gas ($\text{m}^3/10^3\text{m}^3$).

3.1.22

water–liquid ratio

WLR

The water volume flow rate, relative to the total liquid volume flow rate (oil and water), at actual conditions (operating pressure and temperature), expressed as a percentage.

3.1.23

water volume correction factor

B_w

Ratio of water volume at elevated pressure and temperature conditions to the water volume at standard conditions (bbl/bbl, m^3/m^3).

3.1.24

well flow model

Mathematical equation, correlation, or algorithm relating well physical parameters or data to flow.

3.1.25

well rate determination

The process to quantify an oil well's production of gas, oil, and water, or a gas well's production of gas, condensate, and water.

3.2 Acronyms, Abbreviations, and Symbols

For the purposes of this document, the following acronyms, abbreviations, and symbols apply.

B_g	gas volume correction factor
B_o	oil volume correction factor
B_w	water volume correction factor
bbl	barrel
bbl/d	barrels per day
CGR	condensate–gas ratio
EOR	enhanced oil recovery
EOS	equation of state
ft ³	cubic feet
GLR	gas-liquid ratio
GOR	gas–oil ratio
GVF	gas volume fraction
mcf	thousand cubic feet
mscf	thousand standard cubic feet (at standard conditions)
mscf/d	thousand standard cubic feet per day (at standard conditions)
m ³	cubic meter
m ³ /d	cubic meters per day
PVT	pressure, volume, temperature
R_s	solution gas–oil ratio
r_s	solution condensate–gas ratio
S&W	sediment and water
scf	standard cubic foot
VFM	virtual flow meter
WGR	water–gas ratio
WLR	water–liquid ratio

4 Production Well Testing in Upstream Measurement and Allocation

4.1 Introduction

Although preferred, continuous direct measurement of well production for use in upstream measurement and allocation is usually not a practical option for most operators. Periodic direct measurement is achievable, however, and can be used for determining applicable well rates. Thus, the periodic direct measurement, or well test, becomes an integral activity in upstream measurement and allocation.

Well testing provides a means of determining the production characteristics of a well. A well test can be conducted for a variety of reasons, including an evaluation of the productive potential of a well (incorporating wellbore flow capacity and reservoir limits), a measurement of the gas–oil ratio (GOR), a means to sample reservoir fluids, or some other specific item (refer to Annex A for a more detailed description of the various well tests for oil and gas wells).

For use in upstream measurement and allocation, a well test is referred to as a production well test and is defined as the fluid measurement of gas, oil, and water from a single well during a specified length of time under controlled operational conditions. In the case of an oil well, it is the ability of the well to produce oil, water, and gas. For a gas well, it is the ability of the well to produce gas, and sometimes accompanying fluids, such as condensate and water. In each case, the reported volumes are corrected to some agreed standard conditions of pressure and temperature, for example 101.325 kPa and 15 °C (14.696 psia and 60 °F).

4.2 Reasons for Production Well Testing

4.2.1 General

Efficient management of well production depends upon the timely detection of well changes and the ability to measure and accurately control the forces influencing well performance. A major well management component is well rate determination through production well testing. Determining well rates is not only essential for efficient production operations, it is also a reporting requirement for state and federal agencies, can impact revenue, and is necessary for a complete and accurate historical accounting of reservoir and well performance. Important decisions such as production methods and optimization schemes, enhanced oil recovery (EOR) programs, and development drilling are made from this information.

4.2.2 Regulatory/Statutory Requirements

Regular reports of production from oil and gas wells are required by the states and the U.S. Government for federal and Indian leases. There are several reasons why governmental agencies require well production information. In states with proration laws, and on federal lands, well rates are reported to provide conservation commissions and regulatory bodies with data necessary for establishing production rates that prevent waste and for allocating production between fields and wells within individual fields. Taxes such as severance taxes (direct tax on production) and ad valorem taxes (mineral and property taxes based on value) are levied against oil and gas production, with the reported well rates sometimes serving as a basis for tax determination. Regulatory agencies generally stipulate the method for determining reported well rates (e.g. periodic production well test) and the frequency of reporting.

An additional production reporting consideration involves the statutory requirements of the Sarbanes–Oxley Act. The U.S. Government requires the full accountability and verification of corporate financial statements, which includes the proper measurement and accounting of oil and gas production. Depending on the production allocation scenario, production well testing can be a key factor in the reporting process.

4.2.3 Economics

There are numerous economic reasons for determining well rates, but all revolve about the advantage gained from knowing the production trends and characteristics of individual wells. Maximum daily revenue can only be achieved when timely and accurate well rates reflect the producing capability of each well on a lease. In

many producing situations, such as where operators are competitive in a common reservoir, high-volume reservoir pattern flooding is being conducted, or wells are restricted to producing allowables set by regulatory agencies, the revenue from oil and gas not produced because of well failure is either lost or drastically reduced. Moreover, commingled production between partner companies can create allocation scenarios where well rates are used as the basis for revenue splits among the producers. Similar to regulatory requirements, commercial agreements can stipulate the method of well rate determination and production well testing, and the frequency of reporting.

4.2.4 Reservoir Management

Reservoir management involves strategies based on analyses of geologic, reservoir, and production data to optimize the development of a reservoir in an efficient and effective manner. The collection and analyses of rock and fluid property data, reservoir pressures, and temperatures, along with reservoir production data, enable reservoir engineers to construct both geological and reservoir flow models that are crucial in creating and updating reservoir management strategies. The reservoir flow models are vital for understanding the driving forces (either naturally occurring or artificially created) that combine to move fluids in a reservoir. Production well tests allow reservoir engineers to recognize these driving forces and initiate programs that affect them.

4.2.5 Production Management

Production management involves strategies based on analyses of process and production data to optimize the design and operation of both wells and production facilities in an efficient and effective manner. The collection and analyses of fluid property data, process pressures, and temperatures, along with well production data, enable petroleum engineers to construct both well and facility models that are crucial in creating and updating production management strategies. Production well tests allow petroleum engineers to optimize wellbore hydraulics and evaluate wellwork benefits. Furthermore, analysis of well and process production data is utilized in optimizing process production throughput, pipeline flow assurance activities, and facility design such as separation, water disposal, pumping, and compression.

4.3 Production Well Testing and Additional Methods for Determining Well Rates

4.3.1 General

The traditional method of well rate determination has predominantly been the periodic production well test through direct measurement of gas, oil (condensate), and water. The introduction of new technologies and complex commingled production scenarios (e.g. subsea wells commingled and flowing to a single offshore installation) have expanded the scope of well rate determinations to include inline multiphase flow measurements, rate calculations, and three-phase fluid modeling.

Shown in Figure 1 is a well rate determination tree that summarizes the various methods for ascertaining well production rates and outlines the necessary equipment, techniques, and application.

Well rate determinations can either be from direct measurement or from estimates. Measured well rates can be generated via continuous measurement systems, such as dedicated separators or inline meters, or via periodic measurement systems such as test separators or test meters. Estimated well rates can be derived through subtraction or by-difference calculations of direct measurements of commingled flow, or by use of flow models.

Inherent to all well rate determination methods is a direct measurement of well production. When continuous measurement systems are not used on a well, a production well test becomes imperative to periodically directly measure well rates. This is required to validate by-difference estimated well rates (i.e. validate and/or update well flow rate models) or adjust the well rates (i.e. gas well single-phase measurement) for use in upstream measurement and allocation.

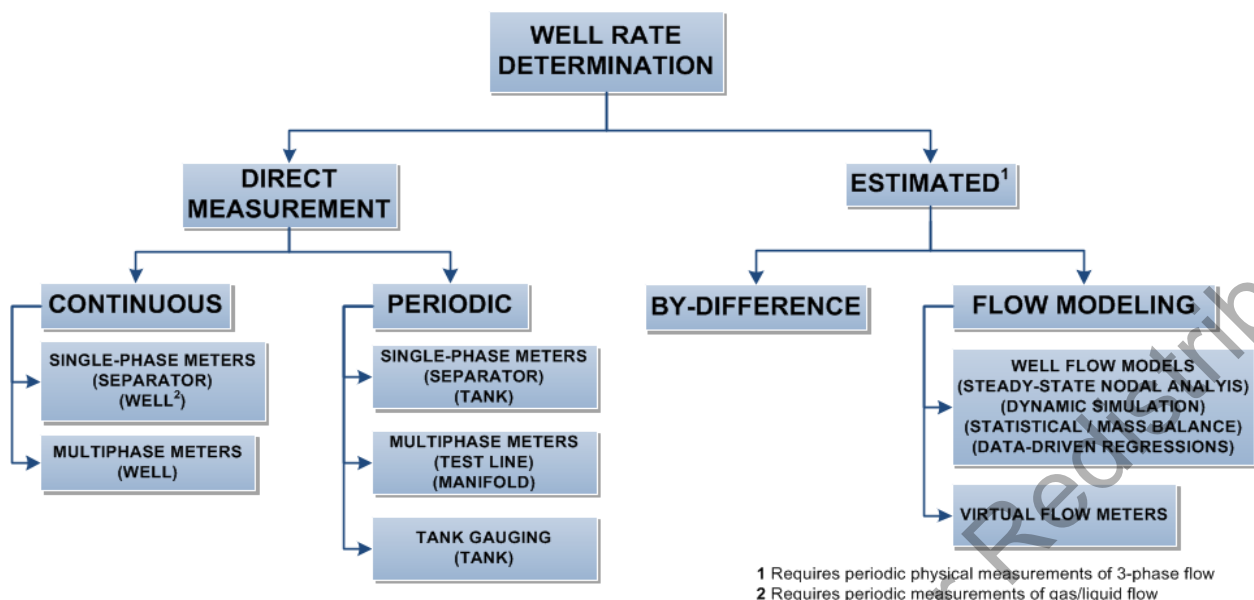


Figure 1—Well Rate Determination Tree

4.3.2 Direct Measurement

Well rate determination through direct measurement has traditionally been via multiphase flow separation into multiple single-phase streams, where single-phase flow meters and online water determination devices (when applicable) are applied to independently measure the flow. Separation can be two-phase (gas and liquids) or three-phase (gas, oil/condensate, water) and is ordinarily accomplished with gravity separation in the form of a large vessel or a compact separator if total separation can be achieved. Separation and single-phase flow measurements can be applied for either continuous or periodic well rate determination, depending on the well and production facility alignments. Typically, several wells utilize the same separation vessel for production, necessitating the process of periodically sampling the flow rate of each individual well. The periodic measured flow rates are generally only representative of well production for conditions (e.g. wellhead pressure) that resemble those during the measurement timeframe.

A more recent direct measurement method involves the application of multiphase flow meters. As with separation-based measurement systems, multiphase flow meters can be applied for either continuous or periodic well rate determination (i.e. production well testing). Multiphase flow meters can be located directly on the wellhead or production flowline, in production manifolds, or dedicated production well testing flowlines, where the same periodic flow rate sampling methodology for a separation-based production well test applies.

An additional direct measurement method for gas wells employs single-phase meters directly on the wellhead or production flowline. The single-phase devices are typically differential pressure meters, and individual gas flow rates can be continuously monitored. Liquid production is not measured, and in situations where liquid production is significant (adversely impacting the gas measurement), corrections to the gas measurement can be applied. When corrections are used, periodic direct measurement of both gas and liquids is generally required.

4.3.3 Estimated

Well rate determination by estimating three-phase flow rates is accomplished either through by-difference calculations or by applying well flow models or virtual flow metering. By-difference well rate determination is a subtraction of a directly measured well (or wells) production from a commingled point direct measurement total, and an assignment of production to an unmeasured well included in the original commingled production measurement. This method is not a true measurement, but a calculation (inferred measurement). As with

periodic direct flow measurement techniques, by-difference estimation provides a flow rate sample applicable for the conditions at which it was derived.

With well pressure and temperature data, it is also possible to use well flow models to provide estimates of three-phase flow information. Such well flow models can be used based on data regressions or more rigorous well models used in nodal analysis. Additionally, simple rate tables relating well flow to temperature and pressure are sometimes applied.

A newer estimation method using VFMs automates the use of models relating measured quantities (e.g. pressure, temperature) to flow, providing continuous real-time three-phase flow information. Such VFMs utilize computer software and real-time sensor data from well, flowlines, and production facilities for continuous multiphase flow estimation. The models can range from simple to complex, are in most cases proprietary, and periodically are updated with direct flow measurement information.

5 Conducting a Production Well Test

5.1 Preparation

5.1.1 General

The most efficient and productive attempt at production well testing is made possible through organized preparation. Operators should understand their responsibilities and all production well testing requirements, then implement planning and test preparation activities prior to initiating a production well test. These activities should include the development and maintenance of applicable production well testing objectives, acceptance criteria, procedures, and contingency plans. Additional verification on the condition of the complete production well test system (reservoir, well, flow delivery, separation, and fluid measurement) should also be implemented.

NOTE API RP 11V5^[1] and API RP 11V8^[2] provide specific production well testing recommendations for gas-lifted wells.

5.1.2 Responsibility

The production well test shall be the responsibility of the operator.

Production well testing may be conducted by the operator or contracted to a service company that specializes in well testing.

The operator or contracted service company may utilize the installed equipment at the facility for production well testing. To avoid the expense of a number of widely scattered stationary well test installations, some operators might prefer to purchase or lease portable well test units (separator-based or multiphase flow meters) that may be aligned with individual wells for the desired production well test and then moved to another location.

5.1.3 Requirements

Production well testing requirements are often cited in regulatory permits, commercial agreements, and operator's policies. This can include test frequency and duration, and the use of the production well test measurement in well rate determination scenarios and/or allocations. The application of this document shall be in conformance with all applicable regulations, permits, and agreements.

All production well test requirements outlined in regulations, permits, or agreements shall be documented.

5.1.4 Objectives

Objectives of the production well test should be established from the documented requirements outlined in regulations, permits, and agreements. The objectives should also include reservoir and production management considerations, along with practices and policies specific to each operator.

The production well test objectives should clearly define:

- production well test frequency, duration, and reporting;
- fluid sampling activities during production well testing;
- production well test use in well rate determination and production allocations;
- production well test use in well or reservoir evaluation.

Production well test objectives are critical to understanding the motivation for the test and any special considerations that can influence the design and execution of the production well testing operation. Consultation with applicable reservoir, production, and flow assurance engineers should be ongoing as part of defining the production well test objectives.

5.1.5 Documentation and Record Retention

Documentation and record retention policies shall be instituted by the operator to provide an audit trail of the production well testing operation and results. In addition to documented production well test requirements, recorded information and data should include:

- process flow diagram(s) denoting all equipment and flow paths in the production well test system;
- equipment list for the production well test system (e.g. meters, transmitters, samplers, analyzers, separators, etc.);
- performance specifications associated with the production well test equipment (e.g. meter uncertainty);
- established procedures associated with certification, calibration, verification, testing, and inspection of all production well test equipment;
- established procedures for conducting the production well testing operation;
- description of associated sampling methods, analysis, and frequency (all fluids);
- applicable well-specific fluid property information (e.g. oil and gas compositions);
- applicable well-specific equation of state (EOS) or fluid property correlations (PVT characterization);
- software versions for all associated computer calculations;
- historical accounting of previous production well tests;
- acceptance criteria used to evaluate the production well tests;
- contingency plans.

5.1.6 Acceptance Criteria

Acceptance criteria for use in production well test evaluation should be established and documented prior to conducting production well testing operations. The acceptance criteria should be based on consideration of the entire production well testing system (reservoir, well, flow delivery, separation, fluid measurement). Sections 5.3.2 and 5.3.3 provide various acceptance criteria for consideration.

5.1.7 Procedures

Procedures for conducting production well testing should be established and documented prior to production well testing operations. The procedures should include information relevant before and during the production

well test, such as the sequence of events, equipment adjustments, data acquisition, and logging. In addition, pre-production well test activities such as fluids, production, and equipment verification steps should be included (refer to 5.2.2, 5.2.3, and 5.2.4).

Procedures specific to the operation of the production well test system will differ by system and are at the discretion of the operator.

5.1.8 Contingency Plans

Contingency plans for production well testing operations should be established and documented prior to initiating a production well test. Specific considerations for inclusion in a contingency plan include:

- production well test system equipment failure;
- adverse well flow conditions (e.g. nonstabilized flow; test conditions different from normal conditions);
- low-energy wells unable to flow in isolation to the measurement point;
- production well test data that do not meet acceptance criteria.

5.2 Initiation and Measurement

5.2.1 General

Production well testing initiation and measurement constitutes the active operation of conducting a production well test. Several verifications should be implemented concurrently prior to measurement and data collection for the production well test, including fluid, production, and equipment verification. These verification activities encompass the entire production well testing system (refer to Annex B for a description of the production well test system) and are vital to ensuring a comprehensive understanding for the production well test. Individuals should be assigned to perform the verification activities in alignment with their normal duties (e.g. a reservoir engineer for fluid verification). Once verification has been completed, the production well test should be performed as follows:

- well isolation;
- system purge and well flow stabilization;
- well measurement;
- data recording.

Figure 2 summarizes the initiation and measurement steps and workflow of a production well test.

5.2.2 Fluid Verification

Initiating a production well test should include a verification of the applicable reservoir fluid properties and flow conditions, particularly if any changes are anticipated from the previous production well test. Initiating a production well test should therefore include knowledge of the type of reservoir, reservoir recovery mechanism and any potential production chemistry or flow assurance issues (e.g. paraffins, asphaltenes, hydrates, scale) that can invalidate the production well test.

NOTE The production well test system should be maintained and operated in a manner that reflects the changes in the reservoir and subsequent well production over time. The production well test system should be capable of accommodating both the change in fluid properties that can accompany an EOR method (e.g. an EOR miscible gas injection flood alters the composition of the produced hydrocarbons) and the possible increase in additional fluids recovered (e.g. increased water production from an EOR waterflood).

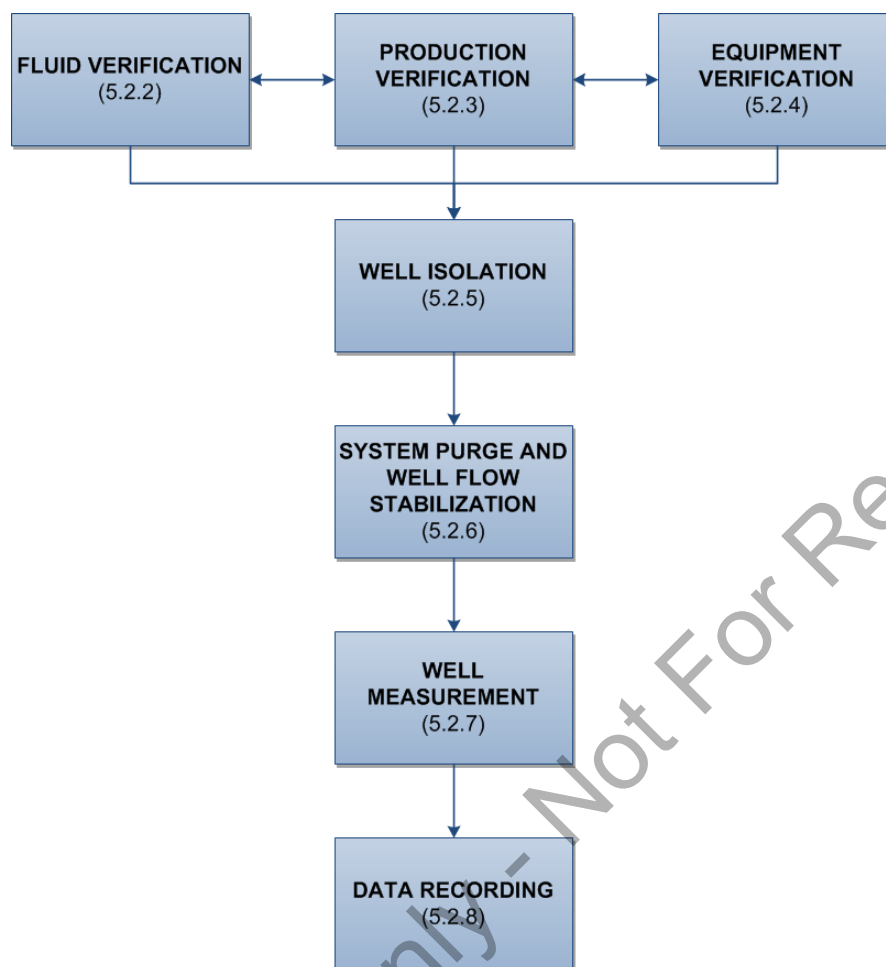


Figure 2—Production Well Test Initiation and Measurement Workflow

A sampling plan should be developed for initiation during the production well test to update if necessary the information incorporated in the fluid verification, and should be based upon an understanding of the phase behavior of the reservoir fluids (Annex B provides a brief overview and description of reservoir fluid classifications and phase behavior). A PVT analysis (for production well test phase behavior application data, refer to 6.2) of the reservoir fluids should be included in the sampling plan if prior PVT analysis is no longer representative of the reservoir fluids.

Highly variable flow rates and dynamic flow conditions due to the various fluid properties and flow regimes at the sampling point should be evaluated for any impact on the production well test sampling operation. This includes both online and manual sampling systems and methods for hydrocarbons, and manual watercut sampling where online water determination devices are not used.

There are several types of liquid and gas sampling systems or procedures that are available for use in production well testing. It is not the intent of this document to specify a sampling system or procedure for the production well testing system. Nor is it the intent of this document to encourage the use of one system or approach over another. However, liquid and gas sampling systems and procedures should be capable of obtaining fluid samples that are deemed to be representative and within the operator's acceptable tolerances for fluid quality.

Applicable standards that should be referenced for liquid sampling in production well testing include API MPMS Ch. 8.1, API MPMS Ch. 8.2, and API 87.

An applicable standard that should be referenced for gas sampling in production well testing is API *MPMS* Ch. 14.1.

NOTE 1 Consideration for EOR sampling requirements should be included in the production well testing process, as accurate production well test data along with EOR evaluation data can be leveraged to increase reservoir recovery.

NOTE 2 There are no industry standards on multiphase sampling and analysis. Additionally, with the exception of API 87, the sampling standards referenced were not written for direct application in a production well testing environment. This does not preclude the use of the standards, but the operator should be aware of any limitations of the standard in the applied sampling application.

Table 1 provides suggested focus areas and associated activities for verifying fluid information. The information should be applicable at the individual well level and used as a tool in fluid verification prior to each production well test. It is at the operator's discretion to determine which fluid verification activities are warranted, based on reasonable expectations that relevant factors have changed since the previous production well test.

NOTE Annex B provides additional information that can be used in establishing fluid verification activities.

5.2.3 Production Verification

In the process of initiating a production well test, operators should verify if any changes in wellbore configuration or operation have occurred since the previous production well test. Production well testing should always be performed in a manner that takes into account any previous well workovers or interventions, with recognition for the potential impact of changed well performance (i.e. wellbore hydraulics and well flow patterns).

Depending on the type of workover or intervention, produced fluid properties and phase behavior can change and should be addressed prior to conducting a production well test on the worked-over well (refer to fluid verification, 5.2.2). In addition, any drawdown limitations should be acknowledged prior to conducting a production well test and not exceeded during stabilization or production well testing measurement.

Production well testing of cyclical wells should take into account the variable nature of the producing well flow (i.e. production declines and dynamic GORs). In addition, wells that are prone to liquid loading (e.g. low rate gas well with high liquid-gas ratio) should be evaluated for any induced slugging impact on the production well test system.

During production well testing, there should be no change in chemical treatment from normal operations, unless a treatment program is specifically required to conduct the production well test (e.g. de-emulsification to promote separation in a test separator, or methanol treatment in a long subsea flowline used for production well testing). Production well testing should be performed with an awareness of the various chemical treatment programs and the potential impact on produced well flow.

Production well testing operations should always include a verification on the flow delivery system between the well and measurement point. Flowline elevation and geometry configurations that can affect the well flow pattern (e.g. liquid hold-up or slugging) should be evaluated, and dynamic flow behavior should be analyzed prior to and during a production well test, as dynamic conditions can take several hours or days to stabilize.

Production well testing operations should always include knowledge of any potential flow assurance or production chemistry threats to the production well test system that can introduce an impact on the flow dynamics and well flow pattern of the applicable well.

Table 1—Summary of Suggested Fluid Verification Activities

Focus Area	Verification Activity	Potential Impact on Production Well Test
Reservoir classification	<p>Classify reservoir as:</p> <ul style="list-style-type: none"> — dry gas, — wet gas, — gas condensate, — critical fluid, — volatile oil, — black oil. <p>Understand the depletion path (pressure reduction) in the reservoir and if phase boundaries have been crossed (i.e. the bubble point or hydrocarbon dew point).</p>	<p>Reservoir depletion across a phase boundary (i.e. bubble point or hydrocarbon dew point) can alter reservoir fluid properties (particularly for gas condensates) from values used in previous production well tests.</p> <p>Two-phase flow (liquid/gas) in the reservoir can influence wellbore hydraulics, leading to non-stable (e.g. slugging) well flow during production well testing.</p>
Reservoir recovery mechanisms	<p>Classify reservoir recovery mechanism as:</p> <ul style="list-style-type: none"> — solution-gas drive, — gas-cap drive, — water drive, — gravity drainage. <p>Verify EOR methods (e.g. miscible or thermal processes).</p> <p>Assess potential for such factors as:</p> <ul style="list-style-type: none"> — increased water production (e.g. aquifer support in a water drive, or waterflooding in an EOR application); — changing water properties (e.g. changing salinity between formation water and injected water); — hydrocarbon compositional changes (e.g. from miscible gas injection). 	<p>Fluid property changes (hydrocarbon and water) from previous production well test.</p> <p>Increased production volumes (e.g. water) exceeding the capacity of the production well test system.</p>
Fluid properties	<p>Verify the following reservoir fluid properties:</p> <ul style="list-style-type: none"> — composition (e.g. N_2, CO_2, C_1, C_2, C_3, etc.); — bubble point pressure or hydrocarbon dew point pressure, PVT studies (phase envelopes); — API gravity/density; — viscosity; — B_o, B_g, B_w, R_s, r_s applicable for production well test conditions (refer to 6.2); — paraffin content, wax appearance temperature, and pour point; — asphaltene content and asphaltene onset pressure; — sulfur content (including H_2S). <p>Verify water chemistry, including:</p> <ul style="list-style-type: none"> — physiochemical parameters (e.g. pH, resistivity, conductivity, density, total dissolved solids, total suspended solids, dissolved CO_2); — soluble anionic and cationic species (e.g. chloride, bromide, phosphate, barium, strontium, lithium); — neutral species (e.g. sulfur). <p>Assess potential for production chemistry and flow assurance threats such as:</p> <ul style="list-style-type: none"> — scale deposition; — corrosion; — hydrates; — wax, paraffin deposition; — asphaltene precipitation and deposition; — emulsions, foams; — material compatibility. <p>Assess fluid property requirements for applicable measurement systems (refer to Table 3).</p>	<p>Production well test system hydraulics can be negatively impacted by production chemistry and flow assurance threats.</p> <p>Outdated fluid property information (e.g. compositions, PVT characterization) used in meter configuration or calculations can compromise the production well test results.</p>
Sampling plan	<p>Establish (or update) sampling plan with the following activities:</p> <ul style="list-style-type: none"> — determine fluid sample requirements (through fluid, production, and equipment verification activities); — evaluate flow conditions at the sample point, and sampling infrastructure; — coordinate with any other engineering disciplines requiring fluid sampling; — establish specific sampling (and analysis) techniques, protocols, and procedures, along with the frequency of sampling. <p>Initiate sampling during the production well test (well measurement).</p>	<p>Sample and analysis activity can provide updated fluid property information for production well test use.</p> <p>Sampling during production well testing can require a coordination of activities and timing between various parties (e.g. sample after system purge and well flow stabilization and during well measurement).</p>

Table 2 provides suggested focus areas and associated activities for verifying production information. The information should be applicable at the individual well level and used as a tool in production verification prior to each production well test. It is at the operator's discretion to determine which production verification activities are warranted, based on reasonable expectations that relevant factors have changed since the previous production well test.

NOTE Annex B provides additional information that can be used in establishing production verification activities.

5.2.4 Equipment Verification

Initiating a production well test should include a verification of the equipment used, including flow isolation, separation, and measurement equipment. The equipment verification should assess general equipment viability. Unmaintained equipment, noncalibrated instruments, and improper operation of production well test equipment can invalidate the production well test results. The production well test equipment should be viable over the life of the facility. Viable refers to equipment that is sized for the anticipated well flows, the correct application of technology, and a system that is inclusive of all the measured parameters of interest. This can result in replacement or upgrading equipment to satisfy the desired objectives, or alternatively, it can mean that a higher uncertainty is accepted for the production well test result.

NOTE Viability also applies to the operation and maintenance of the production well test equipment.

A periodic, routine check should be made of all production well test equipment to ensure that the equipment is in good working order. The frequency for checking the equipment will vary depending on the producing characteristics of the wells and associated problems (if apparent). If a production well test appears inaccurate, or does not meet acceptance criteria requirements, a check of the production well test equipment should be conducted to determine if the issue is a result of faulty or misapplied equipment.

Flow isolation is imperative to production well testing, and processes should be implemented to verify that the production well testing system is capable of isolation of single well flow.

For the production well test information to be representative of the normal flow from a well, the operator should verify that the test separation vessel is sized appropriately to handle the produced fluids from the applicable well. This includes:

- test separators sufficiently sized to allow for full separation (i.e. sufficient residence time, in either two-phase or three-phase operation);
- test separators sufficiently sized to allow normally producing full well flow (e.g. separation efficiency might not be compromised, but a large producing well might need to be choked back to accommodate the test separator).

NOTE Production well testing a well at a reduced volume (rate) due to separator size constraints and extrapolation of the measured volume (rate) to an estimated quantity at normal conditions is not within the scope of this document. In most cases, a linear relationship between well choke setting and production does not exist.

To handle flow variations with incoming flow rates, separator liquid level sensors and control valves should be included in the design and operation of a production well test separator. The extent of automatic and manual controls on the separator should be known and understood during production well testing operations.

Fluid emulsions and the impact on inefficient separation should be understood and managed accordingly. The addition of heat and/or chemical (e.g. demulsifiers) might be required and should be initiated prior to engaging in the production well test. Moreover, periodic vessel cleaning should be considered if sand production is significant.

Production well testing using partial separation techniques should be conducted with full knowledge of any limitations introduced by measuring fluid phases that are not completely single-phase (refer to Annex B).

Table 2—Summary of Suggested Production Verification Activities

Focus Area	Verification Activity	Potential Impact on Production Well Test
Well configuration	<p>Classify well completion, evaluating:</p> <ul style="list-style-type: none"> — completion type: open-hole, cased-hole, number of production strings (tubing); — wellbore trajectories; — number of producing zones, number of laterals; — dry-tree or wet tree (subsea); — surface or subsurface choke. <p>Classify artificial lift mechanism as:</p> <ul style="list-style-type: none"> — rod pump; — plunger; — electrical submersible pump; — subsurface hydraulic piston pump; — subsurface hydraulic jet pump; — gas lift. <p>Assess potential for altered well production and fluid properties due to well completion or artificial lift mechanism modifications, such as:</p> <ul style="list-style-type: none"> — access to new production zones (e.g. new perforations, opening a sliding sleeve, a new side-track); — recompletions (e.g. new tubing, velocity string); — wellbore interventions (e.g. cleanouts, scale squeeze, fracturing); — addition, removal, or conversion of artificial lift mechanism. 	<p>Access to new production zones can alter the fluid properties of the well from values used in previous production well tests.</p> <p>Modifications to artificial lift mechanisms can alter wellbore hydraulics and observed well flow patterns. Additionally, increased production volumes (e.g. water) can exceed the capacity of the production well test system.</p>
Well operability	<p>Verify well operability factors such as:</p> <ul style="list-style-type: none"> — drawdown limitations (choke settings); — chemical treatment type and amount (e.g. methanol, de-emulsifiers, foam breakers); — artificial lift settings; — cycle well production (i.e. intermittent production due to either artificial lift mechanism or well shut-in and recharge); — production volumes (gas, oil, water, and sand or solids). <p>Evaluate well configuration and operability factors and assess potential impacts on wellbore hydraulics, separation, and measurement such as:</p> <ul style="list-style-type: none"> — production volumes relative to equipment capacity; — multiphase flow (i.e. flow regimes); — liquid hold-up, gas line pack, slugging flow (i.e. dynamic conditions); — gas–oil ratio (GOR), gas–liquid ratio (GLR), water–liquid ratio (WLR) (watercuts), gas volume fraction (GVF); — emulsions, foaming; — well flow pattern at the measurement point and flow stabilization. 	<p>Well operability factors can introduce flow regimes that present challenges for efficient separation and/or measurement, particularly well flow stabilization for production well testing.</p> <p>Drawdown limitations can constrain the producing potential of the well (e.g. to minimize sand production and downhole completion damage) and subsequent flow isolation for production well testing.</p>
Flow delivery	<p>Verify flow delivery factors (between the well and the measurement point) such as:</p> <ul style="list-style-type: none"> — flowline length, topography, and geometry; — flow isolation (e.g. flow diverter valves); — commingled well production; — production volumes (gas, oil, water, and sand or solids); — potential production chemistry and flow assurance threats (refer to Table 1); — transient effects (e.g. valve openings or closures); — flowline pigging. <p>Evaluate flow delivery and assess potential impacts on flowline hydraulics, separation, and measurement such as:</p> <ul style="list-style-type: none"> — production volumes relative to equipment capacity; — multiphase flow (i.e. flow regimes); — liquid hold-up, gas line pack, slugging flow (i.e. dynamic conditions); — GOR, GLR, WLR (watercuts), GVF; — emulsions, foaming; — well flow pattern at the measurement point and flow stabilization. 	<p>Flow delivery factors can introduce flow regimes that present challenges for efficient separation and/or measurement, particularly well flow stabilization for production well testing.</p> <p>Production well test system hydraulics can be negatively impacted by production chemistry and flow assurance threats.</p>

It is not the intent of this document to specify a meter type, tank gauging method, or measurement approach for the production well testing system. Nor is it the intent of this document to encourage the use of one approach over another. However, single-phase and multiphase flow metering systems should be capable of measuring the flow within the operator's acceptable tolerances for flow measurement. Manual tank gauging methods or automatic tank gauging systems should be capable of measuring the liquid volume within the operator's acceptable tolerances for volumetric measurement. This should also include sediment and water (S&W) determination. Additionally, online water determination devices should be capable of measuring the full range of expected watercuts.

The application of single-phase flow metering in separator and tank-based production well testing should follow API *MPMS* Ch. 20.2.

NOTE API *MPMS* Ch. 20.2 addresses the configuration and operation of flow metering equipment, and the effects on the quality of the flow measurement result due to fluid properties, production processing, and associated flow conditions for meters used in separation-based measurement, including test separators.

The application of multiphase flow metering in production well testing should follow API *MPMS* Ch. 20.3.

The application of manual tank gauging for tank-based production well testing should follow API *MPMS* Ch. 3.1A and API *MPMS* Ch. 18.1.

The application of automatic tank gauging for tank-based production well testing should follow API *MPMS* Ch. 3.1B, API *MPMS* Ch. 3.3, and API *MPMS* Ch. 3.6.

The application of temperature and pressure transmitters for production well testing should follow API RP 551 and API *MPMS* Ch. 21.1.

NOTE For the application of online water determination devices for production well testing, refer to API TR 2570^[3].

Table 3 provides suggested focus areas and associated activities for verifying equipment information. The information should be applicable at the production well test system level and used as a tool in equipment verification prior to each production well test. It is at the operator's discretion to determine which equipment verification activities are warranted, based on reasonable expectations that relevant factors have changed since the previous production well test.

NOTE Annex B provides additional information that can be used in establishing equipment verification activities.

Table 3—Summary of Suggested Equipment Verification Activities

Focus Area	Verification Activity	Potential Impact on Production Well Test
Flow isolation	Verify ability to isolate single well flow (or multiple wells if production well testing by-difference) throughout the production well test system. Where applicable, periodically conduct zero-rate testing of the production well test system (i.e. a no-flow test of the system to ensure no volumetric flow is measured).	Other flow sources beyond the well(s) evaluated can compromise the production well test.
Separation system	<p>Classify separation system, evaluating:</p> <ul style="list-style-type: none"> separator technology (i.e. two-phase or three-phase separator, heater-treater, partial separation system); number of separators (e.g. high pressure, low pressure); separator size (e.g. gas and liquid capacity); level, temperature, and pressure control; separator operation (e.g. continuous or batch); additional operability factors (e.g. solids removal, chemical additions, compatibility with fluids). <p>With production verification information (refer to Table 2), evaluate separation systems and assess potential for such factors as:</p> <ul style="list-style-type: none"> insufficient separator size for full separation (i.e. residence time); insufficient separator size to accommodate production well testing at 	Insufficiently sized separators (or insufficient residence time) and/or inefficient separator operation can lead to challenging flow regimes for measurement systems.

Focus Area	Verification Activity	Potential Impact on Production Well Test
	<p>normal flow rates;</p> <ul style="list-style-type: none"> — inefficient separator operation (e.g. level, temperature, pressure, fluid emulsions, solids accumulation, dump cycles); — liquid carry-over, gas carry-under; — operation outside the separator operating envelope; — the need for additional heat and/or chemical treatments. 	
Measurement systems	<p>Classify measurement systems, evaluating:</p> <ul style="list-style-type: none"> — meters (e.g. single-phase, multiphase); — tank measurement (e.g. manual, automatic); — fluid quality systems (e.g. sample systems, online water determination devices); — applicable fluid flows (i.e. an account of gas, oil, water production, gas lift, power fluid). <p>Verify meters are configured with the required fluid property information. For example, single-phase meters:</p> <ul style="list-style-type: none"> — composition, — density (standard and flowing conditions), — dynamic viscosity, — specific gravity, — compressibility factor (standard and flowing conditions), — velocity of sound. <p>For multiphase flow meters:</p> <ul style="list-style-type: none"> — constituent compositions (including H₂S, CO₂, and total sulfur); — constituent phase densities (function of temperature and pressure); — bulk gas and liquid viscosities (function of temperature and pressure); — water chemistry (salts, conductivity, salinity); — heavy metals; — B_o, B_g, B_w, R_s, r_s applicable for production well test conditions (refer to 6.2); — normally occurring radioactive material; — foaming and emulsion tendencies; — production chemicals. <p>With production verification information (refer to Table 2), evaluate measurement systems and assess potential for such factors as:</p> <ul style="list-style-type: none"> — exceeding meter rangeability; — unrepresentative fluid properties (meter configuration); — installation effects (e.g. nonideal flow patterns, two-phase flow through the primary element); — adverse process conditions (e.g. temperature, pressure, vibrations, or pulses). <p>Understand the impact on measurement uncertainty and if acceptable uncertainty tolerances have been exceeded.</p>	<p>Outdated fluid property information (e.g. compositions, PVT characterization) used in meter configuration can compromise the production well test results.</p> <p>Insufficiently sized meters and/or installation effects can adversely impact measurement uncertainty and exceed acceptable tolerances for the production well test.</p>
General equipment check	<p>Verify equipment viability with the following check list.</p> <ul style="list-style-type: none"> — Check for leakage along the entire flow path of the production well test system. This includes any diverter valves, flowlines, separators, and tanks used in the production well test system. — Check the operation of all associated control valves, dump valves, and back-pressure valves in the production well test system. — Check that the well choke is not cut or obstructed and that in the case of an adjustable choke check it will zero properly. — Check that the positions of all isolation valves are in the correct position and that the proper valves for well alignment into the measurement system (separator, multiphase flow meter, or tank) are open. — Check for any accumulations of paraffin, sand, or scale in the production well test vessels, tanks, or meters. — Check applicable temperature and pressure monitoring devices are operational (in addition, ensure the devices are properly calibrated). — Check applicable measurement devices or systems (e.g. multiphase flow meters, single-phase meters, online water determination devices, tank gauging systems, tank tables) are operational (in addition, ensure the devices are properly calibrated). 	<p>An operational checklist can ensure equipment readiness and viability for the duration of the production well test.</p>

5.2.5 Well Isolation

Gas, oil (condensate), and water measurements obtained during the production well test shall be applicable to the well under test only and shall not include production from another source. Production well tests shall be conducted such that a well is isolated in the production well testing system, with no leakage or commingling of production with other wells.

Where more than one well is producing to a separator, tank battery, or multiphase flow meter, provisions shall be made to separate production of the individual well to be production well tested from the other wells producing in the system. This can be in the form of a test flow header into a separate separator, tank battery, or multiphase flow meter. Or, production from the wells not undergoing a production well test can be shut-in.

NOTE For production well testing by-difference, it is understood that the “single well flow” will actually encompass multiple, commingled wells. All requirements and recommendations addressed in 5.2 are applicable to commingled well flows measured in by-difference production well testing, and throughout 5.2 the term “well” can be interchanged with “commingled wells” when referring to by-difference production well testing. Refer to 5.5 for more information on by-difference production well testing.

5.2.6 System Purge and Well Flow Stabilization

A well that is aligned to a production well testing system where fluids from previous well production exist shall be flowed for a time sufficient to purge the previous well fluids prior to measurements on the well under test. The production well testing system retention time and liquid hold-up (due to elevation changes in the flowline) should be accounted for in calculating the purge time. This should include consideration of the flow delivery and separation applicable to the production well test system.

To ensure that the production data obtained during a production well test is representative of actual well performance, the production well test shall be conducted under similar physical conditions as the well normally produces, including back pressure, chemical and heat treatments, and flow rates. Wells aligned to a production well test system may require adjustments to choke and artificial lift settings in order to produce at the well's normal physical conditions of back pressure and flow rate.

NOTE If the well is tested at a wellhead pressure in excess of normal operating values, the observed production rate will be reduced from normal conditions. Increased back pressure on the well might be unavoidable due to production well test system constraints (e.g. well productivity, artificial lift settings, test separator pressure controls). In this scenario, the repeatability of production well test measurements is important and the operator should conduct the production well testing under the same set of operating conditions (i.e. the same elevated wellhead pressure) for valid comparisons.

The well flow should be stabilized prior to and during the production well test in accordance with the controlled operational conditions validation acceptance criteria for flow stability (refer to 5.3.2). The pre-stabilization period prior to a production well test should be based on any anticipated temporary wellbore or flow delivery hydraulic-induced instabilities. A well is considered to have stabilized or reached stabilized flow when, for a given choke size or producing rate, the flowing tubing head or pumping bottomhole pressure reaches equilibrium and remains relatively constant at a pressure similar to normal operations. For both flowing and pumping wells, this condition is evidenced at the surface by a relatively constant wellhead pressure, in equilibrium and similar to normal operations.

Production flow rates at the measurement point should be stabilized prior to and during the production well test in accordance with the controlled operational conditions validation acceptance criteria for flow stability (refer to 5.3.2). Flow rates at the measurement point are considered to have stabilized once equilibrium is achieved for the production well test system (e.g. flowlines, test separator, or multiphase flow meter). This is monitored through system temperatures, pressures, levels, and flow rates. When wells are aligned to a production well test system, transient conditions and flowline dynamics can impact the stabilization period prior to the production well test. In these situations, production well testing should account for the transient effects when evaluating for flow stability and representative flow both before and during the production well test. Considerable time should be afforded to allow for the transients to dissipate and conditions to stabilize. Liquid hold-up in long flowlines can extend the time prior to stabilization, separator purge times and flow

stabilization periods might not coincide, and both wellbore and flowline slugging can create flow regimes that never fully stabilize.

API RP 11V8 includes more detailed recommendations on evaluating well stability and purge times following transient events (i.e. aligning a well from a production header to a test header) and a preferred method to estimate the time required for pipeline purging (accounting for liquid hold-up).

There should not be any change in operation of production well test system equipment after the stabilizing period begins and during the production well test. Any adjustment of equipment that causes a change in the pressure upstream of the choke on a flowing well under test (or in the casing or wellhead pressure on a pumping well) can result in erroneous production well test data. If a change is made, the stabilizing period should be started over prior to conducting the production well test.

Production well test results on nonstabilized well flow are not readily reproducible and generally do not directly compare with previous or future test data. However, there are production scenarios where stabilized flow conditions (particularly at the measurement point) are not attainable during the production well testing timeframe. These can include conditions arising from severe well slugging (either naturally or through improperly configured or operating artificial lift systems), subsea riser slugging, or artificial lift systems that normally produce a pulsed flow output from the well (e.g. plungers or rod pumps). In these cases, the production well test should reflect “representative” flow conditions in lieu of stabilized flow (refer to 5.2.7).

NOTE “Representative” flow conditions refer to flow conditions that are representative of normal well operating conditions (i.e. the observed well slugging or cyclical behavior during the production well test is similar to that observed during normal operations). This is at the operator’s discretion and typically will vary on a well by well basis.

The artificial lift method should also be considered when evaluating the producing well for flow stability or representative flow characteristics prior to and during the production well test. Adjustments to artificial lift systems should not be made during the stabilization period, as this constitutes a change in well operations.

NOTE In some cases daily variations in temperature are sufficient to affect gas volumes. Gas volume variation caused by daily temperature changes should not be considered as a variation resulting from stabilization.

5.2.7 Well Measurement

When evaluating stabilized or representative flow during a production well test, production well test durations should be over a time period sufficient to ensure enough flow information is obtained to reliably measure volumes indicative of the well’s normal production. Production well testing should account for transient effects when evaluating for flow stability and representative flow both before and during the production well test.

All produced fluids (gas, oil, and water) shall be accounted for during the measurement of the production well test. This includes any side streams that might be a result of multiple vessels used in separation (e.g. water exiting a free water knockout vessel ahead of a heater-treater).

Fluid production measured by tank gauging should be accomplished by gauging the tank at the beginning and end of the production well test, with the total fluid production determined by difference of the two readings. Indicated oil volume should be sampled and corrected for S&W content.

Artificial lift fluids introduced into the production well (e.g. gas lift gas or power fluid) shall be accounted for in the production well test. The artificial lift fluids should be separately measured and subtracted from the measured fluids during the production well test (e.g. gas lift gas volumes subtracted from the measured production well test gas volume). Adjustments to artificial lift systems should not be made during the production well test.

Flow measurement reporting requirements should be understood and applied using the correct PVT information (i.e. correct fluid measurements to standard conditions) for the well during a production well test. Fluid quality information used in the measurement systems should be applicable to the fluids and process conditions (i.e. pressure and temperature) during the production well test.

Flow measurement data should be the totaled volume for the associated meter during the production well test. If an automatic meter totalizer is not used, then the operator should use the meter totalizer initial and final readings that correspond to the production well test start and end times, respectively.

Instantaneous flow measurement data can be used for well flow rate stability determination.

Refer to Section 6 for detailed information on production well test volume and rate calculations.

During production well testing, there should be no change in chemical treatment from normal operations, unless a treatment program is specifically required to conduct the production well test (e.g. demulsification to promote separation in a test separator, or methanol treatment in a long subsea flowline used for production well testing).

Applicable sampling operations that relate to the production well test should be conducted during the well measurement period. This can include compositional information regarding the fluids, sampling for production well testing PVT application, and/or watercut determination.

NOTE Extreme caution should be exercised in handling gases and fluids containing hydrogen sulfide (H_2S). This hazardous substance is highly toxic and under certain concentration can cause illness and death. Special precautions should be taken when testing wells where H_2S is present to be assured that exposure will not exceed the safe maximum allowable concentration for the work period required. Self-contained breathing apparatus should be worn when H_2S concentrations are present that might be injurious to health.

Watercut determination on liquid flows (oil and water) may be obtained through manual or automatic sampling or an online water determination device.

Manual sampling in the presence of emulsions (flowing or tank measurements) should include multiple samples (e.g. three) for analysis of water content. For tanks, several samples of fluid should be taken at different levels in the tank to find the average water content of the oil.

The duration of the production well test is determined by the operator and should be based on historical performance and parameters relating to the applicable well. Important aspects to consider when establishing production well test duration include:

- well producing performance (i.e. whether the well is a cyclical producer);
- flow variability or slugging at the measurement point (due to various factors such as inefficient separation, inefficient separator level control, or batch “dump” cycle volumes exiting a test separator);
- production deferrals (for production well tests that might require other wells to be shut-in);
- availability of production well test equipment.

Understanding flow variability or slugging at the measurement point and how this can affect production well test duration is one of the more challenging considerations when establishing production well test start and stop times. Annex C provides guidance in this regard and an example to aid the operator.

Figure 3 summarizes the key elements and workflow that should be conducted during a production well test.

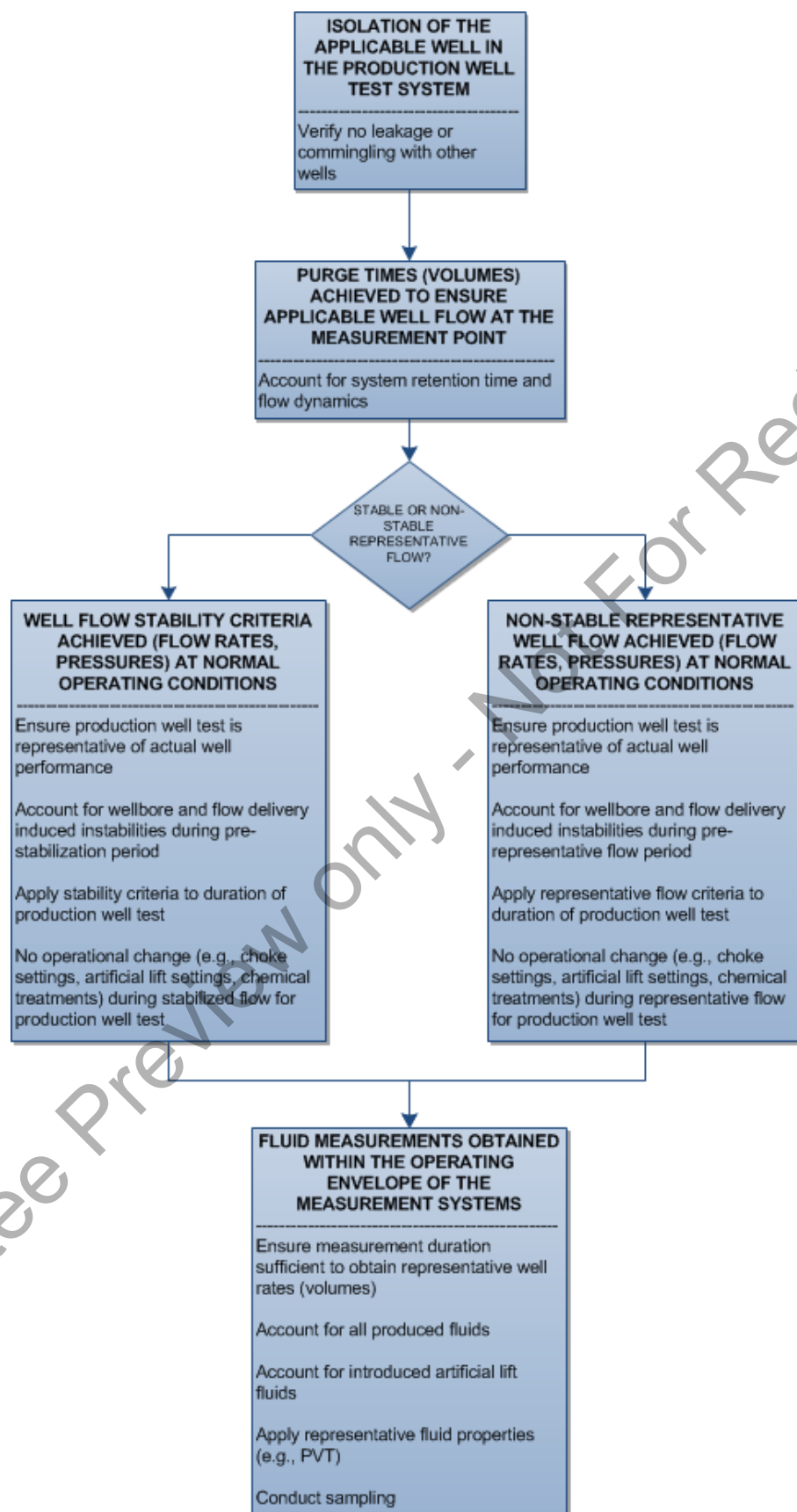


Figure 3—Summary of Production Well Test Elements and Workflow

5.2.8 Data Recording

Recording of the data is an important component of the production well test. The principle method of data recording is at the discretion of the operator (e.g. electronic or paper). Individuals should be assigned to perform data recording activities in alignment with their normal duties (e.g. production personnel for meter data). Reports and the data requirements for a production well test can vary, depending on the applicable regulations, permits, agreements, and operator requirements. For this reason it is not the intent of this document to provide a required universal production well test report. However, an example is provided in Annex D.

The operator shall record the production well test data accurately and completely. Any assumptions regarding equipment status or production well test data should be verified prior to final recording of the information.

5.3 Validation

5.3.1 General

Validation of the production well test is necessary to assure representative well rates. Operators should utilize an evaluation of identified parameters to validate a production well test prior to accepting its use in a well rate determination application. Validation should be through an evaluation of production well test parameters against a set of acceptance criteria for controlled operational conditions during the production well test and in comparison with historical well performance.

5.3.2 Controlled Operational Conditions Validation

It is important that the production well test is validated as representing a measurement of gas, oil, and water from a single well during a specified length of time under controlled operational conditions. The operator should establish and document acceptance criteria for controlled operational conditions validation. The following list provides suggested acceptance criteria parameters for inclusion in controlled operational conditions validation of a production well test:

- well isolation in the production well test system for the duration of the purge, flow pre-stabilization, and production well test measurement period;
- purge times (volumes) sufficient to ensure representative single well flow at the measurement point;
- demonstrated well flow stability for the duration of the production well test:
 - wellhead and/or bottomhole pressure relatively constant and within $\pm 5\%$ of normal operating conditions,
 - wellhead and/or bottomhole temperature relatively constant and within $\pm 5\%$ of normal operating conditions,
 - flow rate variation within $\pm 5\%$ for each phase being tested,
 - watercut variation within $\pm 5\%$,
 - measured GOR variation within $\pm 5\%$,
 - minimum of 4 hours of stable flow.
- fluid measurement obtained within the operating envelope of the measurement system;
- no changes to equipment (e.g. chokes settings, artificial lift settings, chemical injections) for the duration of the production well test.

The range of values for well flow stability is only a starting point. The operator should establish the well flow stability criteria and ranges through evaluation and analysis. Controlled operational conditions validation acceptance criteria might be production well test system specific or well specific. In many cases, historical well performance can be used as a basis to guide establishing the controlled operational conditions validation acceptance criteria.

In situations where well flow does not achieve fully stable conditions (i.e. subsea riser slugging, or artificial lift systems that normally produce a pulsed flow output from the well), the operator should compare the production well test to “representative” flow conditions defined for the well in normal operation.

In situations where validation to controlled operational conditions cannot be obtained for the production well test, the operator should determine if corrections can be applied (e.g. if the wellhead pressure is out of range of the acceptance criteria, the operator may apply a correction factor to the rates/volumes that corresponds to previous production signature information for the well).

5.3.3 Production Signature Validation

When a production well test has been validated, it should be used with previous tests to establish a production signature (or footprint) for the applicable well and production well test system. In turn, the production signature should be utilized as a historical record of well performance to validate subsequent production well tests (it is useful to compare historical trends for a specified set of parameters).

A production signature should be used to validate the representative flow characteristics of a production well test for validation. The operator should establish and document acceptance criteria for production signature validation. The following list provides suggested parameters for inclusion in production signature validation of a production well test:

- gas compositions mole fraction within ± 2 %;
- characterization of the liquid hydrocarbon (e.g. API gravity);
- individual gas, oil (condensate), and water flow rates (or volumes) within ± 5 %;
- measured GOR within ± 10 %;
- well pressures (wellhead and bottomhole) within ± 5 %;
- separator pressures and temperatures within ± 5 %;
- well choke setting unchanged;
- well artificial lift (e.g. power fluid or gas) settings unchanged;
- duration of purge time and flow pre-stabilization period;
- duration of production well test.

The range of values for production signature validation is only a starting point. The operator should establish the acceptance criteria and ranges through evaluation and analysis. Production signature validation acceptance criteria might be production well test system specific or well specific. In many cases, historical well performance can be used as a basis to guide establishing the production signature validation acceptance criteria.

There can be any number of reasons why a production well test might not meet the production signature acceptance criteria. First and foremost, the well might be exhibiting changing performance that was not anticipated prior to the production well test. Second, the restrictions placed on the range of the acceptance

criteria might be too stringent and do not adequately reflect the characteristic behavior of the well. Third, the production well test was in actuality not a valid test and not representative of the well (controlled operational conditions not achieved). Finally, data collection during the production well test (e.g. pressure, temperature, flow measurements) might be erroneous or subject to high uncertainty. Regardless of reason, the entire production well test (system, data collection) should be reviewed and analyzed for contributing factors.

Consideration of historical well production decline is warranted and should be included when acceptance criteria and a production signature are specified. Wells exhibiting a high production decline rate require more production well tests to establish a production signature that is representative of the well's performance. Conversely, when well production declines have leveled off, the number and frequency of production well tests necessary for a representative production signature decreases.

Changes to the well (e.g. well workover or intervention) or flow delivery system (e.g. introduction of riser gas lift or a different routing of flowlines between the well and measurement point) can alter the flowing conditions of the well and the subsequent production signature such that comparison and validation with historical data is no longer applicable. In this scenario, a new production signature should be established for the new flowing conditions and used to valid future production well tests.

5.3.4 Production Well Test Measurement Uncertainty

Measurement in upstream production has a much higher level of uncertainty when compared to measurement at custody transfer conditions. For production well testing, oil is saturated with gas at production pressures and temperatures. Gas is saturated with hydrocarbon and water, and might include entrained liquids. Additionally, oil and water emulsions might be present. It is recognized that these conditions result in the elevated uncertainties relative to custody transfer, where treated gas and de-watered oil pumped from atmospheric tanks are measured.

Owing to the challenges of measurement in an upstream production environment, and the potential complexities of a production well test system, uncertainties associated with the individual phase (i.e. gas, oil, water) measurement results can range from as low as $\pm 2\%$ to as high as $\pm 10\%$ or greater. It is not the intent of this document to specify an uncertainty range acceptable for production well testing. However, the operator should evaluate the importance of the data and assign an acceptable tolerance on uncertainty accordingly. In this endeavor, uncertainties associated with the measurement systems may be evaluated and applied to the final measurement results.

NOTE This can include uncertainties associated with both fluid property and PVT information used in deriving the final measurement result. For more information on calculating measurement uncertainties, refer to API *MPMS* Ch. 13.3^[4].

5.4 Special Case: Continuous Measurement

For wells that are aligned to a continuous measurement system (e.g. a well that is flowing in isolation into a dedicated multiphase flow meter or separator) the need for periodic production well testing might be for reporting purposes only. For example, regulator or partner reporting might require a reported production well test on a periodic basis, such as monthly or every six months. Conducting a production well test on a well aligned to a continuous measurement system should be approached with the methodology described in 5.1, 5.2, and 5.3 (i.e. the same process to determine production well test timing, length, and validation hold true for a periodic "snapshot" of a continuously measured well, as for a well periodically aligned to a production well test system).

As with a periodic production well test conducted with a test separator, multiphase flow meter, or tank battery, the operator should ensure that the production well test with a continuous measurement system is representative of the well's performance in normal operations. With the well continuously isolated in the production well testing system, purging and stabilizing periods prior to the production well test measurement might not be applicable (i.e. no other well fluids and no transient conditions).

5.5 Special Case: Production Well Test By-difference

5.5.1 General

Production well testing by-difference refers to the practice of estimating well rates via subtraction of measured well(s) production from a commingled measurement and an assignment of production to an unmeasured well included in the original commingled measurement. This typically involves shutting in or diverting to another flowline the well to be by-difference production well tested.

This approach to production well testing is often agreed to be acceptable in subsea developments where more than one well produces via a single riser to a surface production facility, and only the commingled production rates of gas, oil, and water are measured. Production well testing by-difference is then executed in preference to a conventional isolation production well test. In many cases, the single well cannot flow stably by itself due to multiphase flow issues.

NOTE Acceptance of by-difference production well testing can also apply onshore, where some wells cannot physically flow alone into a production well test system and are tested by-difference through “piggy-back” testing with another well. Additionally, production well test systems might not be capable of accurately measuring well production (e.g. oversized relative to the well flow rates), thus necessitating the inclusion of another well for both a commingled measurement and a by-difference estimation of the unmeasured producer.

5.5.2 Production Well Test By-difference Process

The two production measurements used in the production well test by-difference subtraction should be conducted in the same manner as a single isolated production well test (refer to 5.2.5). It is important to keep the production levels of the flowing wells constant during the periods the commingled production are measured for the computation of the by-difference result.

A suggested outline of the production well test by-difference process is as follows.

- The by-difference production well tested well is flowed with one or more other wells into the measurement system used for the production well test (e.g. two-phase/three-phase separator or multiphase flow meter).
- The stable total production flows (averaged over at least 6 hours) through the system are recorded as “The Production Level Before Shut-in.” Wellhead and/or bottomhole pressures should be relatively constant and within $\pm 5\%$ of normal operating conditions.
- The well to be production well tested by-difference is shut-in. Wellhead and/or bottomhole pressures for all the other wells are adjusted to be the same (within a few percent) as before the shut-in. This is achieved by varying the production chokes of the wells.
- The stable total production flows (averaged over at least 6 hours) through the system are recorded as “The Production Level After Shut-in.” This should be at most 80 % of the “The Production Level Before Shut-In”.
- The difference between “The Production Level Before Shut-in” and “The Production Level After Shut-in” is taken to be the by-difference production well test of the shut-in well.

NOTE Quantities such as “at most 80 % of The Production Level Before Shut-in” or “averaged over at least 6 hours” are for guidance purposes only. The operator should establish these values through evaluation and analysis. In many cases, historical well performance should be used to inform the evaluation. Additionally, consideration of the measurement uncertainty impact on the by-difference result is warranted (refer to 5.5.3). In commingled production flow, by-difference production well testing of the lowest flow rate well will result in higher relative measurement uncertainties for that well, than if the higher producing well(s) was/were by-difference tested. If possible, direct measurement of the lowest flow rate well is preferred [i.e. by-difference testing the highest flow rate well(s)]. However, in many cases the lowest flow rate well cannot be production well tested in isolation, and higher measurement uncertainties will result.

5.5.3 Special Considerations

Production well testing by-difference is less accurate compared to direct measurement. However, such a production well testing approach is often agreed to be necessary for the economic development of reserves (e.g. deepwater). One source of added measurement uncertainty is the subtraction of two quantities; hence, the percentage uncertainty of the resulting difference is more than the two original individual measurement uncertainties. For example, to achieve a 15 % uncertainty on a 25 % difference, the original measurements are required to be at 3 % uncertainty. This might be difficult to verify in practice. Another potential source of uncertainty relates to the PVT information applied to obtain the production well test result (refer to 6.2). Applied PVT information might be significantly different between measured flows with and without the well to be tested by-difference.

Production well test by-difference requires a well to be shut-in, thereby leading to deferred production and the various operational challenges occasionally encountered with starting up a well. This typically leads to a requirement to minimize production well testing by-difference by extending periods between production well tests. If production well testing by-difference is acceptable or necessary, then the maximum period between production well tests by-difference should be stipulated.

In such cases, production well test by-difference results are typically used as part of a continuous well rate estimation system, for example the validation or tuning of online multiphase flow meters or VFMs (refer to 7.4). Computing continuous well rate estimates based on the results of production well testing by-difference allow the sum of the resulting well rate estimates to be tracked and validated against the commingled flow meters on a daily basis. If the sum of the well daily estimates exceeds, for example, 10 % of the total commingled production consistently over a number of days, this is indicative that the production well test by-difference might no longer be representative of the production for some wells, and testing of selected wells might be required to be brought forward.

NOTE The quantity “If the sum of the well daily estimates exceeds 10 % of the total commingled production” is for guidance purposes only. The operator should establish the value through evaluation and analysis. In many cases, historical well performance should be used to inform the evaluation.

6 Calculating Production Well Test Volumes and Rates

6.1 General

The desired production volume and rate output from a production well test includes the following:

- total volume (mscf, 10^3 m^3) or volumetric rate (mscf/d, $10^3 \text{ m}^3/\text{d}$) of produced gas for the applicable well, corrected to standard conditions;
- total volume (bbl, m^3) or volumetric rate (bbl/d, m^3/d) of produced oil (condensate) for the applicable well, corrected to standard conditions;
- total volume (bbl, m^3) or volumetric rate (bbl/d, m^3/d) of produced water for the applicable well, corrected to standard conditions.

NOTE For production well testing by-difference, it is understood that the “applicable well” will actually encompass multiple, commingled wells. All correction factors and calculations addressed in 6.2, 6.3, 6.4, and 6.5 are applicable to commingled well flows measured in by-difference testing, and the term “well” can be interchanged with “commingled wells” when referring to by-difference production well testing. Refer to 5.5 for more information on by-difference production well testing.

Volume and rate calculations for production well tests vary depending on the type of measurement systems used and artificial lift mechanism deployed. Hydrocarbon phase behavior, watercuts, and introduced artificial lift fluids (i.e. power fluid oil or water, or gas lift gas) shall be accounted for in the calculation of production well test volumes and rates. It is not the intent of this document to specify a calculation approach for every production well test scenario. Nor is it the intent of this document to encourage the use of one approach over

another. However, for guidance applicable to the majority of production well test scenarios, production well test volume and rate calculations are provided for separator, multiphase flow meter, and tank measurement systems.

NOTE 1 When calculating production well test volumes and rates, ensure that the duration of the production well test (i.e. start and stop times) is the same for all of the calculations.

NOTE 2 The gas calculations for single-phase meters provided in this document do not apply to situations where free liquid is present in the gas.

NOTE 3 The liquid calculations for single-phase meters provided in this document do not apply to situations where free gas is present in the liquid.

6.2 Phase Behavior (Production Well Testing PVT Application)

6.2.1 General

At production well test conditions of temperature and pressure, a hydrocarbon liquid is typically at bubble point and a hydrocarbon gas is at dew point. As the hydrocarbon liquid continues through the production process to standard conditions (e.g. atmospheric), the light hydrocarbon components evolve out of the liquid, causing a reduction in liquid volume. Conversely, heavier hydrocarbon components condense out of the gas, causing a reduction in gas volume. To account for the volumetric changes and phase conversions in production well testing calculations, the following PVT properties are applied:

- oil volume correction factor, B_o (the inverse of shrinkage correction factor);
- gas volume correction factor, B_g ;
- water volume correction factor, B_w ;
- solution GOR, R_s ;
- solution condensate–gas ratio (CGR), r_s .

If production well testing is conducted in an environment where the phase behavior cannot be easily represented with B_o , B_g , B_w , R_s , and r_s as described in this document, the operator should refer to the API Draft Standard *Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems* for guidance.

NOTE 1 Throughout the calculations addressed in 6.3, 6.4, and 6.5, B_o , B_g , B_w , R_s , and r_s are denoted with subscripts defining the applicability of the term relative to the production well test conditions of pressure and temperature. For example, $B_{o,sep}$ refers to B_o at separator conditions of pressure and temperature, while $B_{o,mpfm}$ refers to B_o at pressure and temperature conditions at the multiphase flow meter. $B_{o,sep}$ and $B_{o,mpfm}$ are not necessarily equal (only if conditions of pressure and temperature and downstream processing are equivalent), and should be independently determined.

NOTE 2 B_o , B_g , R_s , and r_s as applicable in production well testing (i.e. at production well test conditions of pressure and temperature, e.g. $B_{o,sep}$ or $B_{o,mpfm}$) might or might not be included in a typical reservoir PVT analysis as conducted for reservoir engineering purposes. A typical reservoir PVT analysis is based on PVT studies of either single-phase reservoir fluid (e.g. from a downhole sample) or recombined surface fluids (e.g. separator gas and liquid hydrocarbon) and, depending on the reservoir classification (e.g. black oil or gas condensate), generally include:

- (1) single-stage flash for determination of total hydrocarbon composition;
- (2) constant composition expansion for determination of oil bubble point, undersaturated oil density and isothermal compressibility, two-phase volumetric fluid behavior below bubble point, gas hydrocarbon dew point, gas compressibility, and B_g at hydrocarbon dew point (not production well test conditions of temperature and pressure);

- (3) multistage separator test for determination of total B_o and R_s relative to reservoir conditions of pressure and temperature (not production well test conditions of temperature and pressure, unless specified by the operator in the PVT analysis); differential liberation expansion for determination of residual oil volume, oil density, oil gravity, gas compressibility, and residual B_o and R_s relative to reservoir conditions of pressure and temperature (not production well test conditions of temperature and pressure) that are used to determine the total B_o and R_s (in conjunction with data from the multistage separator test); and
- (4) constant volume depletion for determination of total hydrocarbon composition, two-phase volumetric behavior (i.e. reservoir yields), B_g and r_s as a function of simulated reservoir pressure depletion (not production well test conditions of temperature and pressure). As such, determination of B_o , B_g , R_s , and r_s for production well testing PVT application might require a separate PVT analysis (using similar methods, in particular the multistage separator test) from the typical reservoir studies, using fluid samples obtained at the measurement point (e.g. production well test separator). For more information on PVT studies and analysis, refer to the SPE text *Phase Behavior*^[5].

NOTE 3 B_o , B_g , B_w , R_s , and r_s as applicable in production well testing (i.e. at production well test conditions of pressure and temperature, e.g. $B_{o,sep}$ or $B_{o,mpfm}$) become more relevant at higher pressures and temperatures (i.e. elevated pressures and temperatures lead to greater volumetric changes and phase conversions). Large errors in production well test calculations can result if these properties are not properly determined, such as high-pressure and high-temperature applications of production well test separators or multiphase flow meters. Conversely, B_o , B_g , B_w , R_s , and r_s might not be of enough significance to use in production well testing calculations. It is at the discretion of the operator to assess the validity of the parameters, whether or not estimates for the parameters are warranted, and any associated uncertainty on the production well test result.

6.2.2 Oil Volume Correction Factor

The oil volume correction factor, or B_o , is the ratio of the hydrocarbon liquid volume at elevated pressure and temperature conditions of the production well test system to the hydrocarbon liquid volume at standard conditions (bbl/bbl, m^3/m^3).

NOTE The oil volume correction factor B_o , is the inverse of the shrinkage correction factor, $1/B_o$.

The B_o can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced hydrocarbon liquid at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The B_o is measured as the ratio of hydrocarbon liquid volume at elevated pressure and temperature conditions to the measured hydrocarbon liquid volume at standard conditions. The B_o can be determined in a single-stage flash or under multistage flash conditions. Depending on the process downstream, a multistage flash can lead to a more accurate determination of B_o . The B_o is generally determined in the laboratory at the same time as the GOR, R_s .

NOTE A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

- *Calculation.* A sample of hydrocarbon liquid and a sample of hydrocarbon gas (both in equilibrium) at elevated pressure and temperature conditions of the production well test system are subject to laboratory recombined fluid analysis to obtain the total hydrocarbon composition. EOS modeling using the total hydrocarbon composition and either a simulated single-stage or multistage flash calculation from production well test conditions to standard conditions can provide a calculated estimate of the B_o .

NOTE 1 A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

NOTE 2 The EOS should be capable of determining the PVT properties of interest over the applicable pressure and temperature range. This can include the use of an EOS that has been previously validated against data obtained from a reservoir PVT analysis.

- *Field Measurement.* The B_o can be determined in the field with the procedure outlined in Annex E.

6.2.3 Gas Volume Correction Factor

The gas volume correction factor, or B_g , is the ratio of hydrocarbon gas volume at elevated pressure and temperature conditions of the production well test system to the hydrocarbon gas volume at standard conditions (ft^3/scf , m^3/m^3).

The B_g can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced hydrocarbon gas at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The B_g is measured as the ratio of measured hydrocarbon gas volume at elevated pressure and temperature conditions to the measured hydrocarbon gas volume at standard conditions. The B_g can be determined in a single-stage flash or under multistage flash conditions. Depending on the process downstream, a multistage flash can lead to a more accurate determination of B_g . The B_g is generally determined in the laboratory at the same time as the CGR, r_s .

NOTE A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

- *Calculated.* A sample of hydrocarbon liquid and a sample of hydrocarbon gas (both in equilibrium) at elevated pressure and temperature conditions of the production well test system are subject to laboratory recombined fluid analysis to obtain the total hydrocarbon composition. EOS modeling using the total hydrocarbon composition and either a simulated single-stage or multistage flash calculation from production well test conditions to standard conditions can provide a calculated estimate of the B_g .

NOTE 1 A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

NOTE 2 The EOS should be capable of determining the PVT properties of interest over the applicable pressure and temperature range. This can include the use of an EOS that has been previously validated against data obtained from a reservoir PVT analysis.

6.2.4 Water Volume Correction Factor

The water volume correction factor, B_w , is the ratio of water volume at elevated pressure and temperature conditions of the production well test system to the water volume at standard conditions (bbl/bbl , m^3/m^3).

The B_w can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced water at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The B_w is measured as the ratio of measured water volume at elevated pressure and temperature conditions to the measured water volume at standard conditions.
- *Calculated.* The B_w can be determined with the procedure outlined in Annex F.

6.2.5 Solution GOR

The solution GOR, or R_s (also referred to as the gas-in-solution factor, or GIS), is the ratio of evolved hydrocarbon gas volume at standard conditions (evolved from hydrocarbon liquid as it is lowered in pressure and temperature from elevated pressure and temperature conditions of the production well test system to standard conditions) to the hydrocarbon liquid volume at standard conditions (mscf/bbl , $10^3\text{m}^3/\text{m}^3$).

NOTE The evolved hydrocarbon gas is sometimes referred to as flash gas.

The R_s can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced hydrocarbon liquid at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The R_s is measured as the ratio of the evolved gas to the remaining hydrocarbon liquid, both at standard conditions. The R_s can be determined in a single-stage flash or under multistage flash conditions. Depending on the process downstream, a multistage flash can lead to a more accurate determination of R_s . The R_s is generally determined in the laboratory at the same time as the oil volume correction factor, B_o .

NOTE A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

- *Calculation.* A sample of hydrocarbon liquid and a sample of hydrocarbon gas (both in equilibrium) at elevated pressure and temperature conditions of the production well test system are subject to laboratory recombined fluid analysis to obtain the total hydrocarbon composition. EOS modeling using the total hydrocarbon composition and either a simulated single-stage or multistage flash calculation from production well test conditions to standard conditions can provide a calculated estimate of the R_s .

NOTE 1 A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

NOTE 2 The EOS should be capable of determining the PVT properties of interest over the applicable pressure and temperature range. This can include the use of an EOS that has been previously validated against data obtained from a reservoir PVT analysis.

- *Estimated.* A “rule of thumb” estimate of 1 ft³ (0.0283 m³) of gas per 8 bbl (0.954 m³) of oil per 0.15 psi (1.03 kPa) pressure drop can be used until a measurement or calculation can be performed.

6.2.6 Solution CGR

The solution CGR, or r_s (also referred to as the vaporized CGR), is the ratio of condensed hydrocarbon liquid volume at standard conditions (condensed from gas as it is lowered in pressure and temperature from elevated pressure and temperature conditions of the production well test system to standard conditions) to the hydrocarbon gas volume at standard conditions (bbl/mscf, m³/10³m³).

The r_s can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced hydrocarbon gas at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The r_s is measured as the ratio of condensed hydrocarbon liquid to the remaining gas, both at standard conditions. The r_s can be determined in a single-stage flash or under multistage flash conditions. Depending on the process downstream, a multistage flash can lead to a more accurate determination of r_s . The r_s is generally determined in the laboratory at the same time as the gas volume correction factor, B_g .

NOTE A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

- *Calculation.* A sample of hydrocarbon liquid and a sample of hydrocarbon gas (both in equilibrium) at elevated pressure and temperature conditions of the production well test system are subject to laboratory recombined fluid analysis to obtain the total hydrocarbon composition. EOS modeling using the total hydrocarbon composition and either a simulated single-stage or multistage flash calculation from production well test conditions to standard conditions can provide a calculated estimate of the r_s .

NOTE 1 A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

NOTE 2 The EOS should be capable of determining the PVT properties of interest over the applicable pressure and temperature range. This can include the use of an EOS that has been previously validated against data obtained from a reservoir PVT analysis.

6.3 Separator Measurement Systems

6.3.1 Process Flow Diagram

Figure 4 provides a process flow diagram to aid in the calculation of production well test volumes and rates for two-phase and three-phase separator measurement systems (for two-phase separator measurement systems, the separated water flowline in Figure 4 is not installed and/or commissioned).

6.3.2 Gas

6.3.2.1 Total Gas

The equation for calculating total gas production volume for the duration of the production well test is the following:

$$GV_{\text{tot,sc}} = GV_{\text{sep-g,sc}} + GV_{\text{sep-o,sc}} - GV_{\text{gl,sc}} \quad (1)$$

where

- $GV_{\text{tot,sc}}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3m^3);
- $GV_{\text{sep-g,sc}}$ is gas volume attributed to gas measured at the separator gas outlet, at standard conditions (mscf, 10^3m^3);
- $GV_{\text{sep-o,sc}}$ is gas volume attributed to gas evolved from oil measured at the separator oil outlet (or liquid for two-phase separators), at standard conditions (mscf, 10^3m^3);
- $GV_{\text{gl,sc}}$ is gas volume of artificial lift gas lift gas, at standard conditions (mscf, 10^3m^3).

NOTE 1 The volume of artificial lift gas lift gas, $GV_{\text{gl,sc}}$, refers to gas injected specifically into the well undergoing the production well test. Wells not using gas lift for artificial lift will not have a $GV_{\text{gl,sc}}$ term in the calculation.

NOTE 2 Energy quantities can be calculated instead of volumes.

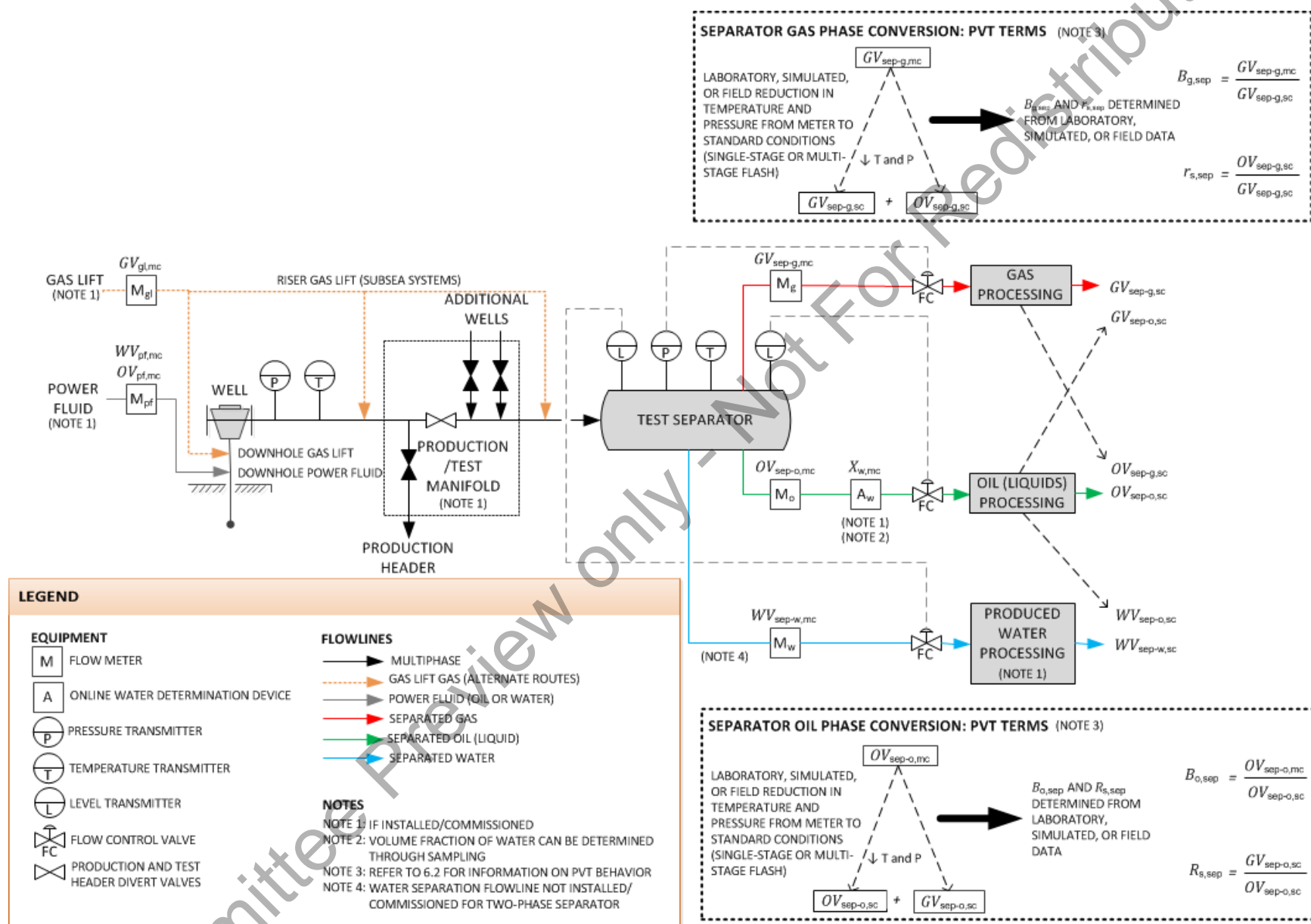
The equation for calculating total gas production rate for the duration of the production well test is the following:

$$GVR_{\text{tot,sc}} = \frac{GV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}}\right)} \quad (2)$$

where

- $GVR_{\text{tot,sc}}$ is gas volumetric rate total for the production well test, at standard conditions (mscf/d, $10^3\text{m}^3/\text{d}$);
- $GV_{\text{tot,sc}}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3m^3);
- Δt is duration of production well test (hours).

An example calculation is provided in Annex G.



6.3.2.2 Gas Volume Measured at the Separator Gas Outlet

The equation for calculating the produced gas attributed to gas measured at the separator gas outlet is the following:

$$GV_{\text{sep-g,sc}} = GV_{\text{sep-g,mc}} \times \frac{1}{B_{\text{g,sep}}} \quad (3)$$

where

$GV_{\text{sep-g,sc}}$ is gas volume attributed to gas measured at the separator gas outlet, at standard conditions (mscf, 10^3 m^3);

$GV_{\text{sep-g,mc}}$ is gas volume of the separator gas outlet flow meter, at meter conditions (mcf, 10^3 m^3);

$B_{\text{g,sep}}$ is gas volume correction factor for separator gas accounting for phase change of produced gas from meter to standard conditions (ft^3/scf , m^3/m^3) (refer to 6.2).

NOTE For separator gas measurement an indicated volume at meter conditions is used, and not an indicated volume at standard conditions. AGA Report No. 8 or similar EOS developed for gas compressibility that can be programmed into a typical gas meter flow computer are applicable for gas compositions that do not undergo mass transfer (phase conversion) with reduction in temperature and pressure. Production well test separator gas is anticipated to experience volumetric change and phase conversion, thus necessitating the determination and use of B_{g} .

An example calculation is provided in Annex G.

6.3.2.3 Gas Volume Evolved from Oil Measured at the Separator Oil (Liquid) Outlet

The equation for calculating the produced gas volume evolved from oil measured at the separator oil (or liquid for two-phase separators) outlet is the following:

$$GV_{\text{sep-o,sc}} = OV_{\text{sep-o,mc}} \times (1 - X_{\text{w,mc}}) \times \frac{1}{B_{\text{o,sep}}} \times R_{\text{s,sep}} \quad (4)$$

where

$GV_{\text{sep-o,sc}}$ is gas volume attributed to gas evolved from oil measured at the separator oil (or liquid for two-phase separators) outlet, at standard conditions (mscf, 10^3 m^3);

$OV_{\text{sep-o,mc}}$ is oil volume of the separator oil outlet (or liquid for two-phase separators) flow meter, at meter conditions (bbl, m^3);

$X_{\text{w,mc}}$ is volume fraction of water in the oil/water mixture adjusted to meter conditions (refer to 6.3.4.5);

$B_{\text{o,sep}}$ is oil volume correction factor for separator oil accounting for phase change of produced oil from meter to standard conditions (bbl/bbl, m^3/m^3) (refer to 6.2);

$R_{\text{s,sep}}$ is solution GOR of evolved gas (from separator to standard conditions) at standard conditions, per oil volume at standard conditions (mscf/bbl, $10^3 \text{ m}^3/\text{m}^3$) (refer to 6.2).

An example calculation is provided in Annex G.

6.3.2.4 Artificial Lift Gas Lift Gas Volume

The equation for calculating the gas lift gas volume measured prior to injection in the well is the following:

$$GV_{gl,sc} = GV_{gl,mc} \times \frac{1}{B_{g,gl}} \quad (5)$$

where

- $GV_{gl,sc}$ is gas volume of artificial lift gas lift gas, at standard conditions (mscf, 10^3 m^3);
- $GV_{gl,mc}$ is gas volume of the gas lift gas flow meter, at meter conditions (mcf, 10^3 m^3);
- $B_{g,gl}$ is gas volume correction factor for gas lift gas accounting for phase change of gas lift gas from meter to standard conditions (ft^3/scf , m^3/m^3) (refer to 6.2).

NOTE Gas lift gas is typically dry gas (i.e. processed, dehydrated gas such as sales gas) that does not contain condensable heavier hydrocarbon components. Therefore, change in gas volume from metering to standard conditions due to hydrocarbon phase conversion is not anticipated. In this case, the use of AGA Report No. 8 or similar EOS developed for gas compressibility that can be programmed into a typical gas meter flow computer can be used, thus gas volume from the meter is reported at standard conditions (mscf, 10^3 m^3).

An example calculation is provided in Annex G.

6.3.3 Oil

6.3.3.1 Total Oil

The equation for calculating total oil production volume for the duration of the production well test is the following:

$$OV_{tot,sc} = OV_{sep-o,sc} + OV_{sep-g,sc} - OV_{pf,sc} \quad (6)$$

where

- $OV_{tot,sc}$ is oil volume total for the production well test, at standard conditions (bbl, m^3);
- $OV_{sep-o,sc}$ is oil volume attributed to oil measured at the separator oil outlet (or liquid for two-phase separators), at standard conditions (bbl, m^3);
- $OV_{sep-g,sc}$ is oil volume attributed to oil condensed from gas measured at the separator gas outlet, at standard conditions (bbl, m^3);
- $OV_{pf,sc}$ is oil volume of artificial lift power fluid oil, at standard conditions (bbl, m^3).

NOTE The volume of artificial lift power fluid oil, $OV_{pf,sc}$, refers to oil injected specifically into the well undergoing the production well test. Wells not using an oil-sourced power fluid for artificial lift will not have a $OV_{pf,sc}$ term in the calculation.

The equation for calculating total oil production rate for the duration of the production well test is the following:

$$OVR_{tot,sc} = \frac{OV_{tot,sc}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (7)$$

where

- $OVR_{tot,sc}$ is oil volumetric rate total for the production well test, at standard conditions (bbl/d, m^3/d);

$OV_{tot,sc}$ is oil volume total for the production well test, at standard conditions (bbl, m³);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.3.3.2 Oil Volume Measured at the Separator Oil (Liquid) Outlet

This calculation approach applies for static sampling methods (e.g. proportional sampling or grab sampling techniques) or inline, continuous water measurements (e.g. online water determination devices) that are used to obtain a representative watercut.

The equation for calculating the produced oil volume attributed to oil measured at the separator oil outlet (or liquid for two-phase separators) is the following:

$$OV_{sep-o,sc} = OV_{sep-o,mc} \times (1 - X_{w,mc}) \times \frac{1}{B_{o,sep}} \quad (8)$$

where

$OV_{sep-o,sc}$ is oil volume attributed to oil measured at the separator oil outlet (or liquid for two-phase separators), at standard conditions (bbl, m³);

$OV_{sep-o,mc}$ is oil volume of the separator oil outlet (or liquid for two-phase separators) flow meter, at meter conditions (bbl, m³);

$X_{w,mc}$ is volume fraction of water in the oil/water mixture adjusted to meter conditions (refer to 6.3.4.5);

$B_{o,sep}$ is oil volume correction factor for separator oil accounting for phase change of produced oil from meter to standard conditions (bbl/bbl, m³/m³) (refer to 6.2).

An example calculation is provided in Annex G.

6.3.3.3 Oil Volume Condensed from Gas Measured at the Separator Gas Outlet

The equation for calculating the produced oil volume attributed to oil condensed from gas measured at the separator gas outlet is the following:

$$OV_{sep-g,sc} = GV_{sep-g,mc} \times \frac{1}{B_{g,sep}} \times r_{s,sep} \quad (9)$$

where

$OV_{sep-g,sc}$ is oil volume attributed to oil condensed from gas measured at the separator gas outlet, at standard conditions (bbl, m³);

$GV_{sep-g,mc}$ is gas volume of the separator gas outlet flow meter, at meter conditions (mcf, 10³m³);

$B_{g,sep}$ is gas volume correction factor for separator gas accounting for phase change of produced gas from meter to standard conditions (ft³/scf, m³/m³) (refer to 6.2);

$r_{s,sep}$ is solution CGR of condensed gas (from separator to standard conditions) at standard conditions, per gas volume at standard conditions (bbl/mscf, m³/10³m³) (refer to 6.2)

NOTE For separator gas measurement, an indicated volume at meter conditions is used, and not an indicated volume at standard conditions. AGA Report No. 8 or similar EOS developed for gas compressibility that can be programmed into a

typical gas meter flow computer are applicable for gas compositions that do not undergo mass transfer (phase conversion) with reduction in temperature and pressure. Production well test separator gas is anticipated to experience volumetric change and phase conversion, thus necessitating the determination and use of B_g .

An example calculation is provided in Annex G.

6.3.3.4 Artificial Lift Power Fluid (Oil) Volume

The equation for calculating the artificial lift power fluid (oil) volume is the following:

$$OV_{pf,sc} = OV_{pf,mc} \times \frac{1}{B_{o,pf}} \quad (10)$$

where

$OV_{pf,sc}$ is oil volume of artificial lift power fluid oil, at standard conditions (bbl, m^3);

$OV_{pf,mc}$ is oil volume of the artificial lift power fluid (oil) flow meter, at meter conditions (bbl, m^3);

$B_{o,pf}$ is oil volume correction factor for power fluid oil accounting for phase change of power fluid oil from meter to standard conditions (bbl/bbl, m^3/m^3) (refer to 6.2).

NOTE Artificial lift power fluid oil is typically stabilized oil (i.e. processed oil such as sales oil) that does not contain volatile light hydrocarbon components. Therefore, reduction in oil volume from metering to standard conditions due to hydrocarbon phase conversion is not anticipated. In this case, the use of volume correction factors for pressure and temperature (e.g. *CPL* and *CTL*) such as addressed in API MPMS Ch. 11.1 should be used, thus $OV_{pf,sc} = OV_{pf,mc} \times CPL \times CTL$, at standard conditions (bbl, m^3).

An example calculation is provided in Annex G.

6.3.4 Water

6.3.4.1 Total Water

The equation for calculating total water production volume for the duration of the production well test is the following:

$$WV_{tot,sc} = WV_{sep-w,sc} + WV_{sep-o,sc} - WV_{pf,sc} \quad (11)$$

where

$WV_{tot,sc}$ is water volume total for the production well test, at standard conditions (bbl, m^3);

$WV_{sep-w,sc}$ is water volume measured at the separator water outlet, at standard conditions (bbl, m^3);

$WV_{sep-o,sc}$ is water volume measured at the separator oil outlet (or liquid for two-phase separators), at standard conditions (bbl, m^3);

$WV_{pf,sc}$ is water volume of artificial lift power fluid water, at standard conditions (bbl, m^3).

NOTE Production well test calculations for two-phase separators will not have a $WV_{sep-w,sc}$ term. The volume of artificial lift power fluid water, $WV_{pf,sc}$, refers to water injected specifically into the well undergoing the production well test. Wells not using a water-sourced power fluid for artificial lift will not have a $WV_{pf,sc}$ term in the calculation.

The equation for calculating total water production rate for the duration of the production well test is the following:

$$WVR_{\text{tot,sc}} = \frac{WV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (12)$$

where

$WVR_{\text{tot,sc}}$ is water volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

$WV_{\text{tot,sc}}$ is water volume total for the production well test, at standard conditions (bbl, m³);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.3.4.2 Water Volume Measured at the Separator Water Outlet

The equation for calculating the produced water volume measured at the separator water outlet is the following:

$$WV_{\text{sep-w,sc}} = WV_{\text{sep-w,mc}} \times \frac{1}{B_{\text{w,sep}}} \quad (13)$$

where

$WV_{\text{sep-w,sc}}$ is water volume measured at the separator water outlet, at standard conditions (bbl, m³);

$WV_{\text{sep-w,mc}}$ is water volume of the separator water outlet flow meter, at meter conditions (bbl, m³);

$B_{\text{w,sep}}$ is water volume correction factor for separator water from meter to standard conditions (bbl/bbl, m³/m³) (refer to 6.2).

An example calculation is provided in Annex G.

6.3.4.3 Water Volume Measured at the Separator Oil (Liquid) Outlet

This calculation approach applies for static sampling methods (e.g. proportional sampling or grab sampling techniques) or inline, continuous water measurements (e.g. online water determination devices) that are used to obtain a representative watercut.

The equation for calculating the produced water volume measured at the separator oil outlet (or liquid for two-phase separators) is the following:

$$WV_{\text{sep-o,sc}} = OV_{\text{sep-o,mc}} \times X_{\text{w,mc}} \times \frac{1}{B_{\text{w,sep}}} \quad (14)$$

where

$WV_{\text{sep-o,sc}}$ is water volume measured at the separator oil outlet (or liquid for two-phase separators), at standard conditions (bbl, m³);

$OV_{\text{sep-o,mc}}$ is oil volume of the separator oil outlet (or liquid for two-phase separators) flow meter, at meter conditions (bbl, m³);

- $X_{w,mc}$ is volume fraction of water in the oil/water mixture adjusted to meter conditions (refer to 6.3.4.5);
- $B_{w,sep}$ is water volume correction factor for separator water from meter to standard conditions (bbl/bbl, m^3/m^3) (refer to 6.2).

An example calculation is provided in Annex G.

6.3.4.4 Artificial Lift Power Fluid (Water) Volume

The equation for calculating the artificial lift power fluid (water) volume is the following:

$$WV_{pf,sc} = WV_{pf,mc} \times \frac{1}{B_{w,pf}} \quad (15)$$

where

- $WV_{pf,sc}$ is water volume of artificial lift power fluid water, at standard conditions (bbl, m^3);
- $WV_{pf,mc}$ is water volume of the artificial lift power fluid (water) flow meter, at meter conditions (bbl, m^3);
- $B_{w,pf}$ is water volume correction factor for artificial lift power fluid water from meter to standard conditions (bbl/bbl, m^3/m^3) (refer to 6.2).

An example calculation is provided in Annex G.

6.3.4.5 Water Volume Fraction

The equation for calculating the volume fraction of water in an oil/water mixture adjusted to metering conditions is the following:

$$X_{w,mc} = \frac{X_{w,sc} \times B_{w,sep}}{X_{w,sc} \times B_{w,sep} + (1 - X_{w,sc}) \times B_{o,sep}} \quad (16)$$

where

- $X_{w,mc}$ is volume fraction of water in the oil/water mixture adjusted to meter conditions;
- $X_{w,sc}$ is volume fraction of water in the oil/water mixture at standard conditions;
- $B_{w,sep}$ is water volume correction factor for separator water from meter to standard conditions (bbl/bbl, m^3/m^3) (refer to 6.2);
- $B_{o,sep}$ is oil volume correction factor for separator oil accounting for phase change of produced oil from meter to standard conditions (bbl/bbl, m^3/m^3) (refer to 6.2).

An example calculation is provided in Annex G.

6.3.5 Gas–Oil Ratio

The equation for calculating the GOR for the production well test is the following:

$$GOR = \frac{GV_{tot,sc}}{OV_{tot,sc}} \times 1000 \quad (17)$$

where

GOR is GOR for the production well test, at standard conditions (scf/bbl, m³/m³);

GV_{tot,sc} is gas volume total for the production well test, at standard conditions (mscf, 10³m³);

OV_{tot,sc} is oil volume total for the production well test, at standard conditions (bbl, m³).

An example calculation is provided in Annex G.

6.3.6 Watercut

The equation for calculating the watercut for the production well test is the following:

$$WC_{sc} = \frac{WV_{tot,sc}}{WV_{tot,sc} + OV_{tot,sc}} \times 100 \% \quad (18)$$

where

WC_{sc} is watercut for the production well test, at standard conditions (%);

WV_{tot,sc} is water volume total for the production well test, at standard conditions (bbl, m³);

OV_{tot,sc} is oil volume total for the production well test, at standard conditions (bbl, m³).

An example calculation is provided in Annex G.

6.4 Multiphase Measurement Systems

6.4.1 Process Flow Diagram

Figure 5 provides a process flow diagram to aid in the calculation of production well test volumes and rates for multiphase measurement systems.

6.4.2 Gas

6.4.2.1 Total Gas

The equation for calculating total gas production volume for the duration of the production well test is the following:

$$GV_{tot,sc} = GV_{mpfm-g,sc} + GV_{mpfm-o,sc} - GV_{gl,sc} \quad (19)$$

where

GV_{tot,sc} is gas volume total for the production well test, at standard conditions (mscf, 10³m³);

GV_{mpfm-g,sc} is gas volume attributed to gas measured at the multiphase flow meter, at standard conditions (mscf, 10³m³);

GV_{mpfm-o,sc} is gas volume attributed to gas evolved from oil measured at the multiphase flow meter, at standard conditions (mscf, 10³m³);

GV_{gl,sc} is gas volume of artificial lift gas lift gas, at standard conditions (mscf, 10³m³);

NOTE The volume of artificial lift gas lift gas, GV_{gl,sc}, refers to gas injected specifically into the well undergoing the production well test. Wells not using gas lift for artificial lift will not have a GV_{gl,sc} term in the calculation.

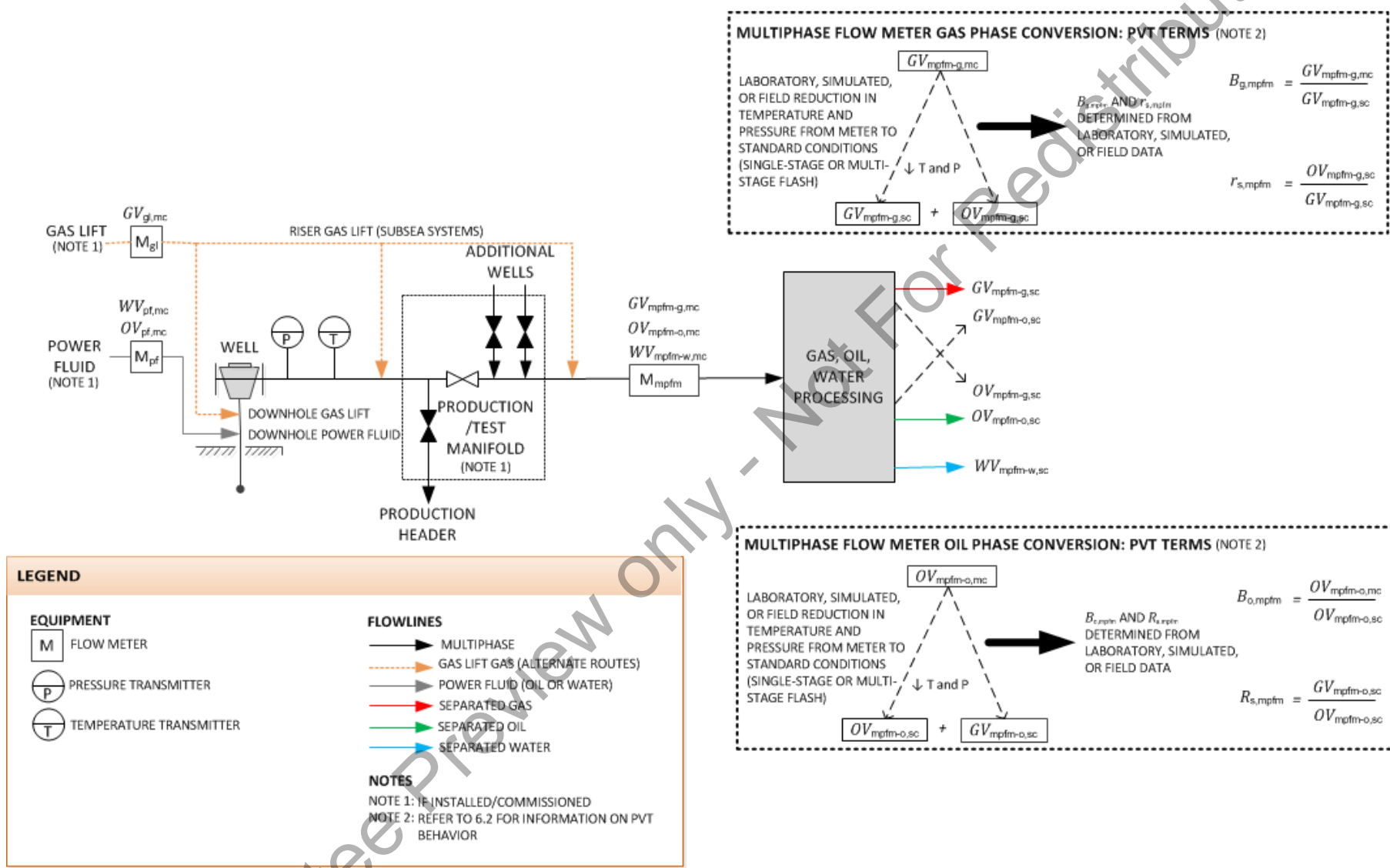


Figure 5—Multiphase Measurement System Process Flow Diagram

The equation for calculating total gas production rate for the duration of the production well test is the following:

$$GVR_{\text{tot,sc}} = \frac{GV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (20)$$

where

$GVR_{\text{tot,sc}}$ is gas volumetric rate total for the production well test, at standard conditions (mscf/d, $10^3 \text{ m}^3/\text{d}$);

$GV_{\text{tot,sc}}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3 m^3);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.4.2.2 Gas Volume Measured at the Multiphase Flow Meter

The equation for calculating the produced gas volume measured at the multiphase flow meter is the following:

$$GV_{\text{mpfm-g,sc}} = GV_{\text{mpfm-g,mc}} \times \frac{1}{B_{\text{g,mpfm}}} \quad (21)$$

where

$GV_{\text{mpfm-g,sc}}$ is gas volume attributed to gas measured at the multiphase flow meter, at standard conditions (mscf, 10^3 m^3);

$GV_{\text{mpfm-g,mc}}$ is gas volume of the multiphase flow meter, at meter conditions (mcf, 10^3 m^3);

$B_{\text{g,mpfm}}$ is gas volume correction factor for multiphase flow meter gas accounting for phase change of produced gas from metering to standard conditions (ft^3/scf , m^3/m^3) (refer to 6.2).

An example calculation is provided in Annex G.

6.4.2.3 Gas Volume Evolved from Oil Measured at the Multiphase Flow Meter

The equation for calculating the produced gas volume evolved from oil measured at the multiphase flow meter is the following:

$$GV_{\text{mpfm-o,sc}} = OV_{\text{mpfm-o,mc}} \times \frac{1}{B_{\text{o,mpfm}}} \times R_{\text{s,mpfm}} \quad (22)$$

where

$GV_{\text{mpfm-o,sc}}$ is gas volume attributed to gas evolved from oil measured at the multiphase flow meter, at standard conditions (mscf, 10^3 m^3);

$OV_{\text{mpfm-o,mc}}$ is oil volume of the multiphase flow meter, at meter conditions (bbl, m^3);

$B_{\text{o,mpfm}}$ is oil volume correction factor for multiphase flow meter oil accounting for phase change of produced oil from meter to standard conditions (bbl/stbbl, m^3/sm^3) (refer to 6.2);

$R_{\text{s,mpfm}}$ is solution GOR of evolved gas (from meter to standard conditions) at standard conditions, per oil volume at standard conditions (mscf/bbl, $10^3 \text{ m}^3/\text{m}^3$) (refer to 6.2).

An example calculation is provided in Annex G.

6.4.2.4 Artificial Lift Gas Lift Gas Volume

Refer to 6.3.2.4.

6.4.3 Oil

6.4.3.1 Total Oil

The equation for calculating total oil production volume for the duration of the production well test is the following:

$$OV_{\text{tot,sc}} = OV_{\text{mpfm-o,sc}} + OV_{\text{mpfm-g,sc}} - OV_{\text{pf,sc}} \quad (23)$$

where

$OV_{\text{tot,sc}}$ is oil volume total for the production well test, at standard conditions (bbl, m³);

$OV_{\text{mpfm-o,sc}}$ is oil volume attributed to oil measured at the multiphase flow meter, at standard conditions (bbl, m³);

$OV_{\text{mpfm-g,sc}}$ is oil volume attributed to oil condensed from gas measured at the multiphase flow meter, at standard conditions (bbl, m³);

$OV_{\text{pf,sc}}$ is oil volume of artificial lift power fluid oil, at standard conditions (bbl, m³).

NOTE The volume of artificial lift power fluid oil, $OV_{\text{pf,sc}}$, refers to oil injected specifically into the well undergoing the production well test. Wells not using an oil-sourced power fluid for artificial lift will not have a $OV_{\text{pf,sc}}$ term in the calculation.

The equation for calculating total oil production rate for the duration of the production well test is the following:

$$OVR_{\text{tot,sc}} = \frac{OV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (24)$$

where

$OVR_{\text{tot,sc}}$ is oil volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

$OV_{\text{tot,sc}}$ is oil volume total for the production well test, at standard conditions (bbl, m³);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.4.3.2 Oil Volume Measured at the Multiphase Flow Meter

The equation for calculating the produced oil volume attributed to oil measured at the multiphase flow meter is the following:

$$OV_{\text{mpfm-o,sc}} = OV_{\text{mpfm-o,mc}} \times \frac{1}{B_{\text{o,mpfm}}} \quad (25)$$

where

$OV_{\text{mpfm-o,sc}}$ is oil volume attributed to oil measured at the multiphase flow meter, at standard conditions (bbl, m³);

$OV_{mpfm-o,mc}$ is oil volume of the multiphase flow meter, at meter conditions (bbl, m³);

$B_{o,mpfm}$ is oil volume correction factor for multiphase flow meter oil accounting for phase change of produced oil from meter to standard conditions (bbl/bbl, m³/m³) (refer to 6.2).

An example calculation is provided in Annex G.

6.4.3.3 Oil Volume Condensed from Gas Measured at the Multiphase Flow Meter

The equation for calculating the produced oil volume attributed to oil condensed from gas measured at the multiphase flow meter is the following:

$$OV_{mpfm-g,sc} = GV_{mpfm-g,mc} \times \frac{1}{B_{g,mpfm}} \times r_{s,mpfm} \quad (26)$$

where

$OV_{mpfm-g,sc}$ is oil volume attributed to oil condensed from gas measured at the multiphase flow meter, at standard conditions (bbl, m³);

$GV_{mpfm-g,mc}$ is gas volume of the multiphase flow meter, at meter conditions (mcf, 10³m³);

$B_{g,mpfm}$ is gas volume correction factor for multiphase flow meter gas accounting for phase change of produced gas from meter to standard conditions (ft³/scf, m³/m³) (refer to 6.2);

$r_{s,mpfm}$ is solution CGR of condensed gas (from meter to standard conditions) at standard conditions, per gas volume at standard conditions (bbl/mscf, m³/10³m³) (refer to 6.2).

An example calculation is provided in Annex G.

6.4.3.4 Artificial Lift Power Fluid (Oil) Volume

Refer to 6.3.3.4.

6.4.4 Water

6.4.4.1 Total Water

The equation for calculating total water production volume for the duration of the production well test is the following:

$$WV_{tot,sc} = WV_{mpfm-w,sc} - WV_{pf,sc} \quad (27)$$

where

$WV_{tot,sc}$ is water volume total for the production well test, at standard conditions (bbl, m³);

$WV_{mpfm-w,sc}$ is water volume measured at the multiphase flow meter, at standard conditions (bbl, m³);

$WV_{pf,sc}$ is water volume of artificial lift power fluid water, at standard conditions (bbl, m³).

NOTE The volume of artificial lift power fluid water, $WV_{pf,sc}$, refers to water injected specifically into the well undergoing the production well test. Wells not using a water-sourced power fluid for artificial lift will not have a $WV_{pf,sc}$ term in the calculation.

The equation for calculating total water production rate for the duration of the production well test is the following:

$$WVR_{\text{tot,sc}} = \frac{WV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (28)$$

where

$WVR_{\text{tot,sc}}$ is water volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

$WV_{\text{tot,sc}}$ is water volume total for the production well test, at standard conditions (bbl, m³);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.4.4.2 Water Volume Measured at the Multiphase Flow Meter

The equation for calculating the produced water volume measured at the multiphase flow meter is the following:

$$WV_{\text{mpfm-w,sc}} = WV_{\text{mpfm-w,mc}} \times \frac{1}{B_{\text{w,mpfm}}} \quad (29)$$

where

$WV_{\text{mpfm-w,sc}}$ is water volume measured at the multiphase flow meter, at standard conditions (bbl, m³);

$WV_{\text{mpfm-w,mc}}$ is water volume of the multiphase flow meter, at meter conditions (bbl, m³);

$B_{\text{w,mpfm}}$ is water volume correction factor for multiphase flow meter water from meter to standard conditions (bbl/bbl, m³/m³) (refer to 6.2).

An example calculation is provided in Annex G.

6.4.4.3 Artificial Lift Power Fluid (Water) Volume

Refer to 6.3.4.4.

6.4.5 Gas–Oil Ratio

Refer to 6.3.5.

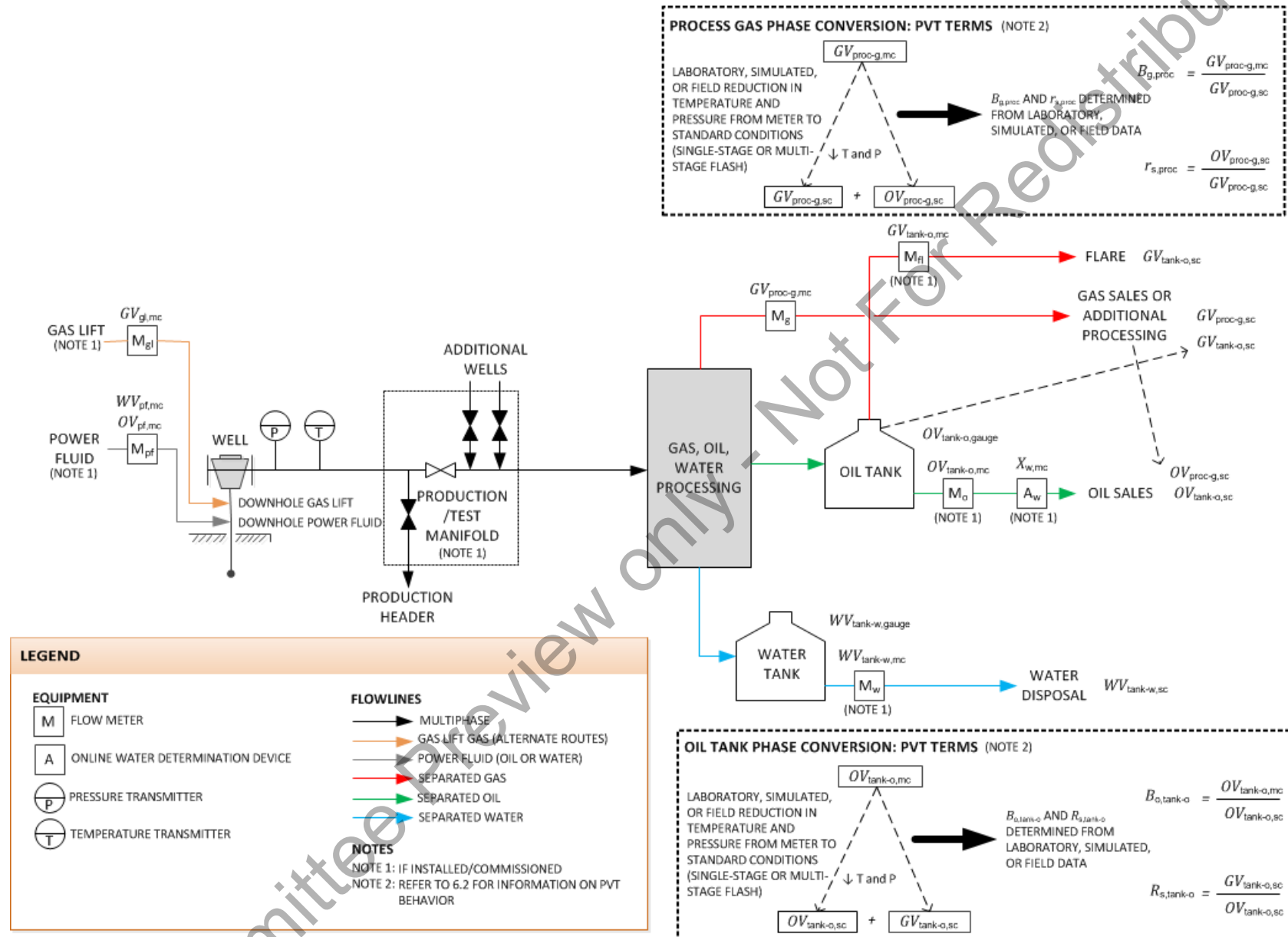
6.4.6 Watercut

Refer to 6.3.6.

6.5 Tank Measurement Systems

6.5.1 Process Flow Diagram

Figure 6 provides a process flow diagram to aid in the calculation of production well test volumes and rates for tank measurement systems.



6.5.2 Gas

6.5.2.1 Total Gas

The equation for calculating total gas production volume for the duration of the production well test is the following:

$$GV_{\text{tot,sc}} = GV_{\text{proc-g,sc}} + GV_{\text{tank-o,sc}} - GV_{\text{gl,sc}} \quad (30)$$

where

$GV_{\text{tot,sc}}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3 m^3);

$GV_{\text{proc-g,sc}}$ is gas volume attributed to gas measured at the process gas outlet, at standard conditions (mscf, 10^3 m^3);

$GV_{\text{tank-o,sc}}$ is gas volume attributed to gas evolved from oil tank (flare), at standard conditions (mscf, 10^3 m^3);

$GV_{\text{gl,sc}}$ is gas volume of artificial lift gas lift gas, at standard conditions (mscf, 10^3 m^3).

NOTE 1 The volume of artificial lift gas lift gas, $GV_{\text{gl,sc}}$, refers to gas injected specifically into the well undergoing the production well test. Wells not using gas lift for artificial lift will not have a $GV_{\text{gl,sc}}$ term in the calculation.

NOTE 2 The volume of gas evolved from the oil tank (flare), $GV_{\text{tank-o,sc}}$, might not be directly measured or determined to contribute significantly to the production well test result. In this case, the $GV_{\text{tank-o,sc}}$ term will not be included in the production well test calculation.

The equation for calculating total gas production rate for the duration of the production well test is the following:

$$GVR_{\text{tot,sc}} = \frac{GV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (31)$$

where

$GVR_{\text{tot,sc}}$ is gas volumetric rate total for the production well test, at standard conditions (mscf/d, $10^3 \text{ m}^3/\text{d}$);

$GV_{\text{tot,sc}}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3 m^3);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.5.2.2 Gas Volume Measured at the Process Gas Outlet

The equation for calculating the produced gas attributed to gas measured at the process gas outlet is the following:

$$GV_{\text{proc-g,sc}} = GV_{\text{proc-g,mc}} \times \frac{1}{B_{\text{g,proc}}} \quad (32)$$

where

$GV_{\text{proc-g,sc}}$ is gas volume attributed to gas measured at the process gas outlet, at standard conditions (mscf, 10^3 m^3);

$GV_{\text{proc-g,mc}}$ is gas volume of the process gas outlet flow meter, at meter conditions (mcf, 10^3m^3)

$B_{\text{g,proc}}$ is gas volume correction factor for process gas accounting for phase change of produced gas from meter to standard conditions (ft^3/scf , m^3/m^3) (refer to 6.2).

NOTE For process gas measurement an indicated volume at meter conditions is used, and not an indicated volume at standard conditions. AGA Report No. 8 or similar EOS developed for gas compressibility that can be programmed into a typical gas meter flow computer are applicable for gas compositions that do not undergo mass transfer (phase conversion) with reduction in temperature and pressure. If process gas is anticipated to experience volumetric change and phase conversion, the application of B_g is necessary. If not, then AGA Report No. 8 or similar EOS can be used and the gas meter can be configured to report at standard conditions (mscf, 10^3m^3).

An example calculation is provided in Annex G.

6.5.2.3 Gas Volume Evolved from Oil Tank

6.5.2.3.1 Direct Gas Measurement

The equation for calculating the produced gas attributed to gas evolved from oil at the oil storage tank is the following:

$$GV_{\text{tank-o,sc}} = GV_{\text{tank-o,mc}} \times \frac{1}{B_{\text{g,tank-o}}} \quad (33)$$

where

$GV_{\text{tank-o,sc}}$ is gas volume attributed to gas evolved from oil tank (flare), at standard conditions (mscf, 10^3m^3);

$GV_{\text{tank-o,mc}}$ is gas volume of the oil tank gas outlet flow meter (flare), at meter conditions (mcf, 10^3m^3);

$B_{\text{g,tank-o}}$ is gas volume correction factor for oil tank gas accounting for phase change of produced gas (flare) from meter to standard conditions (ft^3/scf , m^3/m^3) (refer to 6.2).

NOTE For oil tank gas measurement an indicated volume at meter conditions is used, and not an indicated volume at standard conditions. AGA Report No. 8 or similar EOS developed for gas compressibility that can be programmed into a typical gas meter flow computer are applicable for gas compositions that do not undergo mass transfer (phase conversion) with reduction in temperature and pressure. If oil tank gas is anticipated to experience volumetric change and phase conversion, the application of B_g is necessary. If not, then AGA Report No. 8 or similar EOS can be used and the gas meter can be configured to report at standard conditions (mscf, 10^3m^3).

6.5.2.3.2 Estimate

Alternatively, produced gas attributed to gas evolved from oil at the oil storage tank can be estimated with the following:

$$GV_{\text{tank-o,sc}} = OV_{\text{tank-o,sc}} \times R_{\text{s,tank-o}} \quad (34)$$

where

$GV_{\text{tank-o,sc}}$ is gas volume attributed to gas evolved from oil tank (flare), at standard conditions (mscf, 10^3m^3);

$OV_{\text{tank-o,sc}}$ is oil volume attributed to oil measured at the oil tank, at standard conditions (bbl, m^3) (refer to 6.5.3.2);

$R_{\text{s,tank-o}}$ is solution GOR of evolved gas (from tank to standard conditions) at standard conditions, per oil volume at standard conditions (mscf/bbl, $10^3\text{m}^3/\text{m}^3$) (refer to 6.2).

NOTE This estimation method only applies when the oil tanks are at elevated temperature and pressure with crude oil not fully stabilized.

An example calculation is provided in Annex G.

6.5.2.4 Artificial Lift Gas Lift Gas Volume

Refer to 6.3.2.4.

6.5.3 Oil

6.5.3.1 Total Oil

The equation for calculating total oil production volume for the duration of the production well test is the following:

$$OV_{\text{tot,sc}} = OV_{\text{tank-o,sc}} + OV_{\text{proc-g,sc}} - OV_{\text{pf,sc}} \quad (35)$$

where

$OV_{\text{tot,sc}}$ is oil volume total for the production well test, at standard conditions (bbl, m³);

$OV_{\text{tank-o,sc}}$ is oil volume attributed to oil measured at the oil tank, at standard conditions (bbl, m³);

$OV_{\text{proc-g,sc}}$ is oil volume attributed to oil condensed from gas measured at the process gas outlet, at standard conditions (bbl, m³);

$OV_{\text{pf,sc}}$ is oil volume of artificial lift power fluid oil, at standard conditions (bbl, m³).

NOTE The volume of artificial lift power fluid oil, $OV_{\text{pf,sc}}$, refers to oil injected specifically into the well undergoing the production well test. Wells not using an oil-sourced power fluid for artificial lift will not have a $OV_{\text{pf,sc}}$ term in the calculation.

The equation for calculating total oil production rate for the duration of the production well test is the following:

$$OVR_{\text{tot,sc}} = \frac{OV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (36)$$

where

$OVR_{\text{tot,sc}}$ is oil volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

$OV_{\text{tot,sc}}$ is oil volume total for the production well test, at standard conditions (bbl, m³);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.5.3.2 Oil Volume Measured at the Oil Tank

6.5.3.2.1 Metered Oil Measurement

This calculation approach applies for static sampling methods (e.g. proportional sampling or grab sampling techniques) or inline, continuous water measurements (e.g. online water determination devices) that are used to obtain a representative watercut.

The equation for calculating the produced oil volume attributed to oil measured at the oil tank outlet is the following:

$$OV_{\text{tank-o,sc}} = OV_{\text{tank-o,mc}} \times (1 - X_{w,mc}) \times \frac{1}{B_{o,\text{tank-o}}} \quad (37)$$

where

- $OV_{\text{tank-o,sc}}$ is oil volume attributed to oil measured at the oil tank, at standard conditions (bbl, m³);
- $OV_{\text{tank-o,mc}}$ is oil volume of the oil tank outlet flow meter, at meter conditions (bbl, m³);
- $X_{w,mc}$ is volume fraction of water in the oil/water mixture adjusted to meter conditions (refer to 6.3.4.5);
- $B_{o,\text{tank-o}}$ is oil volume correction factor for oil tank oil accounting for phase change of produced oil from meter to standard conditions (bbl/bbl, m³/m³) (refer to 6.2).

NOTE 1 Tank oil is typically stabilized oil (i.e. processed oil such as sales oil) that does not contain volatile light hydrocarbon components. Therefore, reduction in oil volume from metering to standard conditions due to hydrocarbon phase conversion is not anticipated. In this case, the use of volume correction factors for pressure and temperature (e.g. *CPL* and *CTL*) such as addressed in API MPMS Ch. 11.1 should be used, thus $OV_{\text{tank-o,sc}} = OV_{\text{tank-o,mc}} \times (1 - X_{w,mc}) \times CPL \times CTL$, at standard conditions (bbl, m³).

NOTE 2 It is important that tank outlet measurement for production well test volumes correspond with the calculated gas and water volumes. The timing between beginning and closing oil volumes of the tank (i.e. the production well test oil volume) should align with the volumetric measurements of gas and water.

An example calculation is provided in Annex G.

6.5.3.2.2 Tank Gauging Oil Measurement

Alternatively, the equation for calculating the produced oil volume attributed to oil measured in the oil tank via tank gauging methods (manual or automatic) is the following:

$$OV_{\text{tank-o,sc}} = OV_{\text{tank-o,gauge}} \times (1 - X_{w,sc}) \quad (38)$$

where

- $OV_{\text{tank-o,sc}}$ is oil volume attributed to oil measured at the oil tank, at standard conditions (bbl, m³);
- $OV_{\text{tank-o,gauge}}$ is oil volume of the oil tank determined by tank gauging (manual or automatic), at standard conditions (bbl, m³);
- $X_{w,sc}$ is volume fraction of water in the oil/water mixture at standard conditions.

NOTE It is important that tank gauging for production well test oil volumes correspond with the calculated gas and water volumes. The timing between beginning and closing oil volumes of the tank (i.e. the production well test oil volume) should align with the volumetric measurements of gas and water.

An example calculation is provided in Annex G.

6.5.3.3 Oil Volume Condensed from Gas Measured at the Process Gas Outlet

The equation for calculating the produced oil volume attributed to oil condensed from gas measured at the process gas outlet is the following:

$$OV_{\text{proc-g,sc}} = GV_{\text{proc-g,mc}} \times \frac{1}{B_{\text{g,proc}}} \times r_{\text{s,proc}} \quad (39)$$

where

$OV_{\text{proc-g,sc}}$ is oil volume attributed to oil condensed from gas measured at the process gas outlet, at standard conditions (bbl, m³);

$GV_{\text{proc-g,mc}}$ is gas volume of the process gas outlet flow meter, at meter conditions (mcf, 10³m³);

$B_{\text{g,proc}}$ is gas volume correction factor for process gas accounting for phase change of produced gas from meter to standard conditions (ft³/scf, m³/m³) (refer to 6.2);

$r_{\text{s,proc}}$ is solution CGR of condensed gas (from process to standard conditions) at standard conditions, per gas volume at standard conditions (bbl/mscf, m³/10³m³) (refer to 6.2).

NOTE For process gas measurement an indicated volume at meter conditions is used, and not an indicated volume at standard conditions. AGA Report No. 8 or similar EOS developed for gas compressibility that can be programmed into a typical gas meter flow computer are applicable for gas compositions that do not undergo mass transfer (phase conversion) with reduction in temperature and pressure. If process gas is anticipated to experience volumetric change and phase conversion, the application of B_{g} is necessary. If not, then AGA Report No. 8 or similar EOS can be used and the gas meter can be configured to report at standard conditions (mscf, 10³m³). Additionally, $r_{\text{s,proc}}$ is not used.

An example calculation is provided in Annex G.

6.5.3.4 Artificial Lift Power Fluid (Oil) Volume

Refer to 6.3.3.4.

6.5.4 Water

6.5.4.1 Total Water

The equation for calculating total water production volume for the duration of the production well test is the following:

$$WV_{\text{tot,sc}} = WV_{\text{tank-w,sc}} + WV_{\text{tank-o,sc}} - WV_{\text{pf,sc}} \quad (40)$$

where

$WV_{\text{tot,sc}}$ is water volume total for the production well test, at standard conditions (bbl, m³);

$WV_{\text{tank-w,sc}}$ is water volume measured at the water tank outlet, at standard conditions (bbl, m³);

$WV_{\text{tank-o,sc}}$ is water volume measured at the oil tank, at standard conditions (bbl, m³);

$WV_{\text{pf,sc}}$ is water volume of artificial lift power fluid water, at standard conditions (bbl, m³).

NOTE The volume of artificial lift power fluid water, $WV_{\text{pf,sc}}$, refers to water injected specifically into the well undergoing the production well test. Wells not using a water-sourced power fluid for artificial lift will not have a $WV_{\text{pf,sc}}$ term in the calculation.

The equation for calculating total water production rate for the duration of the production well test is the following:

$$WVR_{\text{tot,sc}} = \frac{WV_{\text{tot,sc}}}{\Delta t \times \left(\frac{1 \text{ day}}{24 \text{ hours}} \right)} \quad (41)$$

where

$WVR_{\text{tot,sc}}$ is water volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

$WV_{\text{tot,sc}}$ is water volume total for the production well test, at standard conditions (bbl, m³);

Δt is duration of production well test (hours).

An example calculation is provided in Annex G.

6.5.4.2 Water Volume Measured at the Water Tank Outlet

6.5.4.2.1 Metered Water Measurement

The equation for calculating the produced water volume measured at the water tank outlet is the following:

$$WV_{\text{tank-w,sc}} = WV_{\text{tank-w,mc}} \times \frac{1}{B_{\text{w,tank-w}}} \quad (42)$$

where

$WV_{\text{tank-w,sc}}$ is water volume measured at the water tank outlet, at standard conditions (bbl, m³);

$WV_{\text{tank-w,mc}}$ is water volume of the separator water outlet flow meter, at meter conditions (bbl, m³);

$B_{\text{w,tank-w}}$ is water volume correction factor for water tank water from meter to standard conditions (bbl/bbl, m³/m³) (refer to 6.2).

An example calculation is provided in Annex G.

6.5.4.2.2 Tank Gauging Water Measurement

Alternatively, the equation for calculating the produced water volume via tank gauging methods (manual or automatic) is the following:

$$WV_{\text{tank-w,sc}} = WV_{\text{tank-w,gauge}} \quad (43)$$

where

$WV_{\text{tank-w,sc}}$ is water volume measured at the water tank outlet, at standard conditions (bbl, m³);

$WV_{\text{tank-w,gauge}}$ is water volume of the tank water determined by tank gauging (manual or automatic), at standard conditions (bbl, m³).

NOTE It is important that tank gauging for production well test water volumes correspond with the calculated gas and oil volumes. The timing between beginning and closing water volumes of the tank (i.e. the production well test water volume) should align with the volumetric measurements of gas and oil.

An example calculation is provided in Annex G.

6.5.4.3 Water Volume Measured at the Oil Tank

6.5.4.3.1 Metered Water Measurement

This calculation approach applies for static sampling methods (e.g. proportional sampling or grab sampling techniques) or inline, continuous water measurements (e.g. online water determination devices) that are used to obtain a representative watercut.

The equation for calculating the produced water volume measured at the oil tank is the following:

$$WV_{\text{tank-o,sc}} = OV_{\text{tank-o,mc}} \times X_{\text{w,mc}} \times \frac{1}{B_{\text{w,tank-o}}} \quad (44)$$

where

$WV_{\text{tank-o,sc}}$ is water volume measured at the oil tank, at standard conditions (bbl, m³);

$OV_{\text{tank-o,mc}}$ is oil volume of the tank oil outlet flow meter, at meter conditions (bbl, m³);

$X_{\text{w,mc}}$ is volume fraction of water in the oil/water mixture adjusted to meter conditions (refer to 6.3.4.5);

$B_{\text{w,tank-o}}$ is water volume correction factor for oil tank water from meter to standard conditions (bbl/bbl, m³/m³) (refer to 6.2).

An example calculation is provided in Annex G.

6.5.4.3.2 Tank Gauging Water Measurement

Alternatively, the equation for calculating the produced water volume attributed to oil measured in the oil tank via tank gauging methods (manual or automatic) is the following:

$$WV_{\text{tank-o,sc}} = OV_{\text{tank-o,gauge}} \times (X_{\text{w,sc}}) \quad (45)$$

where

$WV_{\text{tank-o,sc}}$ is water volume measured at the oil tank, at standard conditions (bbl, m³);

$OV_{\text{tank-o,gauge}}$ is oil volume of the tank oil determined by tank gauging (manual or automatic), at standard conditions (bbl, m³);

$X_{\text{w,sc}}$ is volume fraction of water in the oil/water mixture at standard conditions

NOTE It is important that tank gauging for production well test oil volumes correspond with the calculated gas and water volumes. The timing between beginning and closing oil volumes of the tank (i.e. the production well test oil volume) should align with the volumetric measurements of gas and water.

An example calculation is provided in Annex G.

6.5.4.4 Artificial Lift Power Fluid (Water) Volume

Refer to 6.3.4.4.

6.5.5 Gas–Oil Ratio

Refer to 6.3.5.

6.5.6 Watercut

Refer to 6.3.6.

7 Applying Production Well Test Data for Use in Allocation

7.1 General

Production allocation measurement system design and methodology will dictate if production well test data are used in the allocation calculations for gas, oil, and water. Applying a production well test in an allocation scheme generally consists of either prorating a periodic production well test over a fixed allocation period or using production well test data to update alternative well rate determination methods. In either case, the application of production well test data for use in allocation shall follow the allocation requirements of API MPMS Ch. 20.1.

7.2 Production Well Test Rate Assumed Constant

One method of prorating a production well test over an allocation period consists of using a constant production well test rate with no applied downtime to calculate well production volumes commensurate with the allocation period. Using the production well test volumetric rate terms calculated in 6.3, 6.4, and 6.5, the following equations apply.

NOTE Higher uncertainties associated with the prorated well rates might be realized if well production is not constant throughout the allocation period.

For gas, the prorated gas volume for the allocation period is calculated by the following:

$$GV_{\text{alloc-per,sc}} = GVR_{\text{tot,sc}} \times \frac{1 \text{ day}}{24 \text{ hours}} \times \Delta t \quad (46)$$

where

$GV_{\text{alloc-per,sc}}$ is gas volume for the allocation period, at standard conditions (mscf, 10^3 m^3);

$GVR_{\text{tot,sc}}$ is gas volumetric rate total for the production well test, at standard conditions (mscf/d, $10^3 \text{ m}^3/\text{d}$);

Δt is duration of allocation period (hours);

For oil, the prorated gas volume for the allocation period is calculated by the following:

$$OV_{\text{alloc-per,sc}} = OVR_{\text{tot,sc}} \times \frac{1 \text{ day}}{24 \text{ hours}} \times \Delta t \quad (47)$$

where

$OV_{\text{alloc-per,sc}}$ is oil volume for the allocation period, at standard conditions (bbl, m^3);

$OVR_{\text{tot,sc}}$ is oil volumetric rate total for the production well test, at standard conditions (bbl/d, m^3/d);

Δt is duration of allocation period (hours).

For water, the prorated water volume for the allocation period is calculated by the following:

$$WV_{\text{alloc-per,sc}} = WVR_{\text{tot,sc}} \times \frac{1 \text{ day}}{24 \text{ hours}} \times \Delta t \quad (48)$$

where

$WV_{\text{alloc-per,sc}}$ is water volume for the allocation period, at standard conditions (bbl, m³);

$WVR_{\text{tot,sc}}$ is water volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

Δt is duration of allocation period (hours).

An example calculation is provided in Annex H.

7.3 Production Well Test Rate with Applied Downtime

Another method of prorating a production well test over an allocation period consists of using a constant production well test rate with applied downtime (uptime factor, or UF) to calculate well production volumes commensurate with the allocation period. Using the production well test volumetric rate terms calculated in 6.3, 6.4, and 6.5, the following equations apply.

For gas, the prorated gas volume for the allocation period is calculated by the following:

$$GV_{\text{alloc-per,sc}} = GVR_{\text{tot,sc}} \times \frac{1 \text{ day}}{24 \text{ hours}} \times \Delta t \times UF \quad (49)$$

where

$GV_{\text{alloc-per,sc}}$ is gas volume for the allocation period, at standard conditions (mscf, 10³m³);

$GVR_{\text{tot,sc}}$ is gas volumetric rate total for the production well test, at standard conditions (mscf/d, 10³m³/d);

Δt is duration of allocation period (hours);

UF is uptime factor, ratio of uptime (hours) to duration of allocation period, Δt (hours).

NOTE The uptime factor, UF , can be used to incorporate production ramp-up and ramp-down times during the allocation period. For example, a well producing at half of the gas production well test value during the allocation period can use an UF of 0.50 to account for the reduced production volumes.

For oil, the prorated gas volume for the allocation period is calculated by the following:

$$OV_{\text{alloc-per,sc}} = OVR_{\text{tot,sc}} \times \frac{1 \text{ day}}{24 \text{ hours}} \times \Delta t \times UF \quad (50)$$

where

$OV_{\text{alloc-per,sc}}$ is oil volume for the allocation period, at standard conditions (bbl, m³);

$OVR_{\text{tot,sc}}$ is oil volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

Δt is duration of allocation period (hours);

UF is uptime factor, ratio of uptime (hours) to duration of allocation period, Δt (hours).

NOTE The uptime factor, UF , can be used to incorporate production ramp-up and ramp-down times during the allocation period. For example, a well producing at half of the oil production well test value during the allocation period can use an UF of 0.50 to account for the reduced production volumes.

For water, the prorated water volume for the allocation period is calculated by the following:

$$WV_{\text{alloc-per,sc}} = WVR_{\text{tot,sc}} \times \frac{1 \text{ day}}{24 \text{ hours}} \times \Delta t \times UF \quad (51)$$

where

$WV_{\text{alloc-per,sc}}$ is water volume for the allocation period, at standard conditions (bbl, m³);

$WVR_{\text{tot,sc}}$ is water volumetric rate total for the production well test, at standard conditions (bbl/d, m³/d);

Δt is duration of allocation period (hours);

UF is uptime factor, ratio of uptime (hours) to duration of allocation period, Δt (hours).

NOTE The uptime factor, UF , can be used to incorporate production ramp-up and ramp-down times during the allocation period. For example, a well producing at half of the water production well test value during the allocation period can use an UF of 0.50 to account for the reduced production volumes.

An example calculation is provided in Annex H.

7.4 Production Well Test Rate Validation and Updating of Well Flow Models and Virtual Flow Meters

7.4.1 General

In some allocation scenarios, well flow models or VFMs are used to determine well rates for allocation purposes, with no direct use of a prorated production well test volume. However, in these situations production well test data should be used to validate and update the well flow models and VFMs. Additionally, the concepts for determining volumes and rates previously addressed in Section 6 (e.g. the use of PVT), and the accounting of downtime described in 7.3, also apply for well flow models and VFMs supplying production well volumes for use in an allocation scheme.

7.4.2 Well Flow Models

Well flow models are mathematical equations, correlations, or algorithms relating well physical parameters or data to flow. With pressure and temperature data, well flow models can be used to estimate well multiphase flow rates, even as production chokes or well pressures change. Well flow models that are commonly used include the following.

- *Steady-state, First Principles Nodal Analysis.* These models are usually based on well inflow performance relationships (IPRs), vertical lift performance (VLP), or choke behavior (or a combination thereof). For well rate estimation using nodal analysis, measured pressures and temperatures are input into a nodal analysis program and matched with flow correlations resulting in an estimated multiphase rate. Uncertainty may be reduced by increasing the number of pressure and temperature sensors available (nodes) and with updated data on the composition or properties of the fluid flowing through the system.
- *Non-steady-state (Dynamic), First Principles Transient Behavior.* These models represent transient multiphase behavior in a well, such as unloading or slugging. VFM systems using first principles transient models might also be used to predict instantaneous rates, pressures, and temperatures of flow streams using known or estimated variables at various points (nodes) along the flow stream, from the sand face to the separators. These models are expected to be more accurate compared to static models during transient behavior. However, since transient models depend on the past history of the flow, they might be difficult to tune.

- *Statistical Data Validation and Reconciliation of Mass Balances.* These models integrate wells and the overall production network inclusive of downstream processes (including single-phase measurement points). The fundamental principles applied are the conservation of mass across a production network, and reconciliation based on the expected relative uncertainties of the input data measurements or estimated outputs. The challenge with this approach is in using appropriate measurement uncertainties, and in minimizing localized errors in one part of the production network from affecting the rate estimates for all of the wells in the network.
- *Curve-fitting or Regressions (Data-driven).* These VFM models are typically constructed from periodically conducted physical well tests at multiple rates and generally require less well-level engineering information to set up. Appropriately designed data-driven models with clear basis in the physical understanding of well flow processes are expected to be well suited for interpolating well production between well tests.

Well flow models and associated data are typically deployed through computer software, although the models are manually accessed for updates and validation. Individual well flow models should be calibrated or tuned following each validated production well test. The models should include documentation on the measured parameters used within the model, along with underlying assumptions used in the generation of the well rate estimates (e.g. if GOR, watercut, or reservoir pressure is assumed constant or to decline as a function of production).

7.4.3 VFM Systems

7.4.3.1 Overview

VFM is a real-time computer-based well rate determination method that utilizes well flow models in conjunction with real-time well/process sensor and instrumentation data for continuous multiphase well rate estimation. Well rate estimates can be generated at up to 1-minute intervals. In some cases, the maintenance of the well flow models is partly automated, with the VFM directly accessing production well test data via production data historians.

The predominant application for VFM well rate estimation has been real-time well surveillance and continuous production monitoring and allocation in support of reservoir management and production optimization activities. VFM well rate estimates are generally intended as an enhancement to or a backup for the physical measurement systems used in periodic (e.g. test separator) or continuous (e.g. multiphase flow meter, or dedicated separation) well rate determination. In lieu of physical measurement system failure or unavailability, and provided sufficient sensor and instrumentation input data are still available, VFMs can be applied for well rate determination use to satisfy regulatory or commercial agreement requirements.

Details of VFM systems used for well production allocation should be documented, including the underlying models and algorithms used, how the models are tuned, updated, and validated, and the sensitivity of models to inaccurate input data. Additionally, contingencies in the event of inaccurate input data should be developed.

7.4.3.2 Real-time, Measured Data Inputs

The real-time data inputs to VFM systems are most commonly pressure and temperature sensors and valve or artificial lift equipment set points. Inaccurate or unreliable inputs to VFM systems result in inaccurate well rate estimates. VFM systems should include capabilities for detecting input signal dropouts, flat-lines, data outliers, and other gross errors, and provide alerts for these scenarios along with the ability to suitably condition input signals.

7.4.3.3 VFM Software and Models

The effectiveness or otherwise of VFMs is strongly influenced by the well flow models used, how well the models are updated, and how sensitive the models are to inaccurate data inputs (both measured data and model parameters).

The modeling techniques used in VFMs include the well flow models summarized in 7.4.2. The well flow models are realized as computer software algorithms that receive real-time sensor and instrumentation data inputs and are run at regular intervals to provide multiphase well rate estimates. The software algorithms and databases for VFMs should execute in real-time reliably and be robust to input data and model convergence issues. The software also shall support system validation and model update work processes.

7.4.3.4 System Validation and Model Calibration Processes

The VFM validation and model calibration work process seeks to ensure that the models are properly updated to account for input sensor or instrumentation data, well inflow, vertical lift, or flowline property changes and that the overall system is fit for well rate estimation.

Validation of VFM system output is commonly achieved through comparison against periodic production well tests for the online wells and the reconciliation factor applied to the continuous commingled measurement system. The reconciliation factor is obtained by comparing the sum of the VFM well rate estimates with downstream single-phase meter total flows as follows:

$$\text{Reconciliation Factor} = \frac{\text{Total Production Volume for Period (from Meter)}}{\text{Sum of VFM Estimated Well Production Volumes for Period}} \quad (52)$$

The agreement between the downstream single-phase meter total flows and the sum of the VFM well rate estimates can be monitored in real time and during transient events.

All VFM models shall be periodically updated. Model calibration and update of the VFM system involves the periodic re-tuning of key model parameters such that the VFM well rate estimates match a reference periodic production well test or continuous measurement system result.

7.4.4 Recommendations

7.4.4.1 General

In general, any VFM system is designed to be fit-for-purpose, incorporating relevant input data with processes in place to assure the validity of the estimated well rates. The exact details of implementation and utilization of a VFM system for multiphase well rate estimation will be site and case specific and depend on multiple factors that might or might not be unique to the setup. The following recommendations are offered as guidance on the design and operation of a VFM and are categorized into two basic themes:

- VFM system design,
- VFM operational assurance.

7.4.4.2 VFM System Design Recommendations

- If available, phase sensors such as densitometers and online water determination devices should be used as real-time measured data inputs to the VFM. Unlike multiphase flow meters that have dedicated phase sensors (e.g. densitometers), VFM systems often only use common pressure and temperature sensors as input sources. For such VFM systems—even with detailed multiphase models and very accurate correlations—it will be very difficult to obtain good estimates of watercut or GLRs, as these values change over time [most VFMs require an estimate of watercut and GOR, or CGR and water–gas ratio (WGR) as an input parameter]. This can be attributed to limitations on inherent accuracies normally possible from the pressure and temperature sensors and the numerical conditioning issues associated with inverting models.
- Depending on the type of VFM model used and the extent to which it is set up, other flow measurement sources such as single-phase meters or multiphase flow meters should be used as inputs or as reference points during model update or VFM system validation activities.

- If necessary for the particular VFM model framework to be used, the operator should obtain and utilize all of the valid information on the physical layout and dimensions of the well and/or process, including (but not limited to) the well completions diagram, deviation survey, mechanical and process flow diagrams (with the applicable flowlines, risers, manifolds, topside equipment, etc.), and input data sensor tags. If applicable, the operator should also include any specific equipment operational characteristics such as laboratory-validated choke valve curves or pump curves.
- If necessary for the particular VFM model framework to be used, the operator should obtain and utilize all of the valid information on the fluid properties and PVT behavior for the applicable wells.
- If available and sufficiently reliable, the use of downhole measured input data should be incorporated, particularly pressure (to enable the use of greater pressure drops in the VFM model).

NOTE VFM estimated well rates can be as frequent as one estimate per minute, at the same frequency as the data historian, to once every hour. If deemed necessary, high frequency estimates will be more consistent with a VFM's ability to mimic physical flow meters and will allow detection of transient well behavior such as slugging. However, higher frequency estimates are more computationally demanding and are supported only by some types of VFM models.

7.4.4.3 VFM Operational Assurance Recommendations

- A quality check and sensitivity analysis on both the measured input data and parameters used in the VFM model (this might be initially limited in some green field applications where input data might not be readily available at the time of start-up) should be conducted. VFMs are significantly dependent on the accuracy and availability of measured input data, along with assumptions on certain model parameters. An evaluation of the input quality and a sensitivity analysis that assesses various uncertainties assigned to the measured inputs and model parameters can quantify the impact on the VFM's estimated well rates. Due to unique operating ranges and well flow characteristics, a site-specific analysis is most beneficial.
- Regardless of the specific type of VFM model used, a network-wide flow balance and reconciliation process (whether incorporated as part of the base well rate estimation capability or as part of the VFM system validation) should be applied. Performing a balance and reconciliation can be a useful diagnostic exercise that can be configured to provide alerts against predetermined thresholds on model performance. This in turn can be used to determine model update and VFM system validation frequencies.
- The VFM model shall be periodically tuned or updated with data from physical measurement systems. This can be from either periodic (e.g. production well testing) or continuous (e.g. multiphase flow meter) measurement sources, and includes current fluid property and PVT data for the applicable well. The VFM model calibration frequency will ultimately be determined by evaluation of the VFM model performance and expectations of the operator.
- VFM system alerts should be incorporated for notification when input data are missing or likely incorrect (e.g. input signal flat-lines and communication failures).
- VFM system alerts should be incorporated for notification when input data are indicating operation outside the model operating envelopes (e.g. VFM detection of wells not flowing or flowing at unusually low rates).
- The operator should reference and utilize the methods of uncertainty determination and evaluation as recommended in API RP 85, particularly if there is multiple flow measurement points incorporated within the process.
- The operator should establish a VFM system assurance policy with clear accountabilities for the fit-for-purpose performance of the VFM system, including the processes and procedures for checking reconciliation, updating models, fixing input instrumentation, and acquiring well test/validation data.

7.5 Production Well Test Volume Adjustment of Gas Well Continuous Measurement with Single-phase Meters

7.5.1 General

In some allocation scenarios continuous measurement of gas wells using single-phase meters is used to determine well rates for allocation purposes, with no direct use of a prorated production well test volume. However, in these situations production well test data should be used to validate and update applied meter correction factors for the well continuous measurement system determination of gas and liquid rates. Additionally, the concepts for determining volumes and rates previously addressed in Section 6 (e.g. the use of PVT), and the accounting of downtime described in 7.3, also apply for single-phase gas meters supplying production well volumes for use in an allocation scheme.

7.5.2 Process Flow Diagram

Figure 7 provides a process flow diagram showing gas wells continuously measured with single-phase meters and the ability to be aligned with a production well test system.

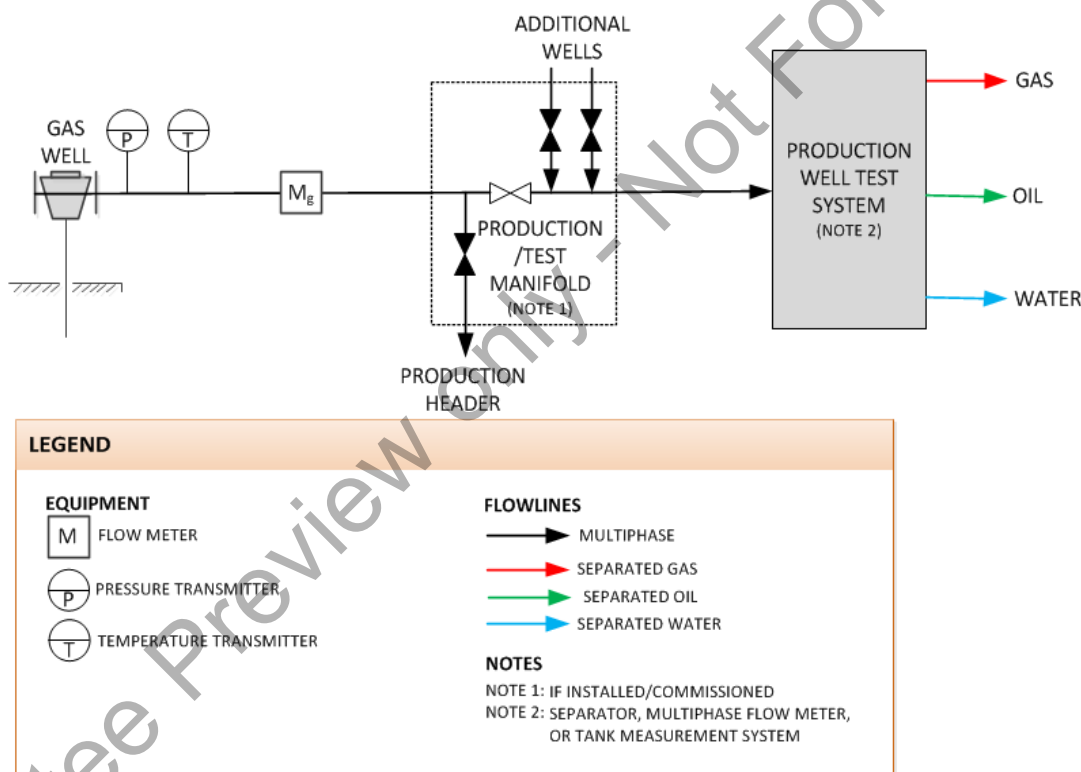


Figure 7—Gas Wells Continuously Measured with Single-phase Meters with the Ability to Align with a Production Well Test System

7.5.3 Well Rate Determination

Gas wells continuously measured with single-phase meters can have reported volumes of gas, oil (condensate), and water used as a well rate determination method in production allocation measurement. The single-phase meters do not directly measure liquid (condensate or water) in the gas flow, and depending on the single-phase meter type and flow rate conditions (e.g. liquid entrainment in the gas, flow regime), the measured gas rates are typically an over-read of the actual gas flow rate. However, using an applied correction for the gas over-read and assigning condensate and water volumetric rates based on the well CGR and WGR, respectively, gas, condensate, and water rates can be estimated for the well.

NOTE It is not the intent of this document to address single-phase meter performance in wet gas flows or over-read correction correlations. For more information, refer to ASME MFC-19G^[6].

7.5.4 Applying Production Well Test Derived Meter Correction Factors

Updating the estimated gas, condensate, and water rates for a single-phase metered gas well using a production well test is accomplished with the application of meter correction factors derived from production well test data. Using the production well test volume terms calculated in 6.3, 6.4, and 6.5, the following equations apply.

NOTE The following production well test derived correction factors are applied with the assumption that relative changes between gas, condensate, and water are ignored with adjustments in well production (i.e. choke changes or dynamic well behavior). For example, CGRs and WGRs are assumed constant for variable well production rates.

For gas, the derived meter correction factor is calculated after the production well test by the following:

$$MCF_g = \frac{GV_{tot,sc}}{GV_{well-test,sc}} \quad (53)$$

where

MCF_g is meter correction factor for gas;

$GV_{tot,sc}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3m^3);

$GV_{well-test,sc}$ is gas volume of the gas well flow meter for the duration of the production well test, at standard conditions (mscf, 10^3m^3).

NOTE 1 For gas well single-phase meter measurement, an indicated volume at meter conditions or at standard conditions can be used. What is important is consistency in use of one volume over the other. The MCF_g derived with a gas well meter volume at standard conditions should only be applied to a gas well meter volume at standard conditions for the necessary adjustment. Conversely, the MCF_g derived with a gas well meter volume at meter conditions should only be applied to gas well meter volumes at meter conditions.

NOTE 2 In some locations a gas equivalent volume is reported. The gas equivalent volume incorporates produced condensate with the produced gas, using a value to convert the liquid volume to gas volume (e.g. 1.1 mscf/bbl). This presents an alternative calculation, whereby $GEV_{tot,sc}$ (gas equivalent volume total for the production well test, at standard conditions) is substituted for $GV_{tot,sc}$ and $GEV_{well-test,sc}$ (gas equivalent volume of the gas well flow meter for the duration of the production well test, at standard conditions) is substituted for $GV_{well-test,sc}$.

Applying the meter correction factor provides a production well test adjusted gas volume:

$$AGV_{well,sc} = GV_{well,sc} \times MCF_g \quad (54)$$

where

$AGV_{well,sc}$ is adjusted gas volume of the gas well flow meter, at standard conditions (mscf, 10^3m^3);

$GV_{\text{well,sc}}$ is gas volume of the gas well flow meter, at standard conditions (mscf, 10^3m^3);

MCF_g is meter correction factor for gas.

For condensate, the derived meter correction factor (based on the production well test measured CGR) is calculated after the production well test by the following:

$$MCF_o = \frac{OV_{\text{tot,sc}}}{GV_{\text{tot,sc}}} \quad (55)$$

where

MCF_o is meter correction factor for oil (condensate) (bbl/mscf, $\text{m}^3/10^3\text{m}^3$);

$OV_{\text{tot,sc}}$ is oil (condensate) volume total for the production well test, at standard conditions (bbl, m^3);

$GV_{\text{tot,sc}}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3m^3).

Applying the meter correction factor provides a production well test adjusted condensate volume:

$$AOV_{\text{well,sc}} = AGV_{\text{well,sc}} \times MCF_o \quad (56)$$

where

$AOV_{\text{well,sc}}$ is adjusted oil (condensate) volume attributed to the gas volume, at standard conditions (bbl, m^3);

$AGV_{\text{well,sc}}$ is adjusted gas volume of the gas well flow meter, at standard conditions (mscf, 10^3m^3);

MCF_o is meter correction factor for oil (condensate) (bbl/mscf, $\text{m}^3/10^3\text{m}^3$).

For water, the derived meter correction factor (based on the production well test measured WGR) is calculated after the production well test by the following:

$$MCF_w = \frac{WV_{\text{tot,sc}}}{GV_{\text{tot,sc}}} \quad (57)$$

where

MCF_w is meter correction factor for water (bbl/mscf, $\text{m}^3/10^3\text{m}^3$);

$WV_{\text{tot,sc}}$ is water volume total for the production well test, at standard conditions (bbl, m^3);

$GV_{\text{tot,sc}}$ is gas volume total for the production well test, at standard conditions (mscf, 10^3m^3).

Applying the meter correction factor provides a production well test adjusted water volume:

$$AWV_{\text{well,sc}} = AGV_{\text{well,sc}} \times MCF_w \quad (58)$$

where

$AWV_{\text{well,sc}}$ is adjusted water volume attributed to the gas volume, at standard conditions (bbl, m^3);

$AGV_{\text{well,sc}}$ is adjusted gas volume of the gas well flow meter, at standard conditions (mscf, 10^3m^3);

MCF_w is meter correction factor for water (bbl/mscf, $\text{m}^3/10^3\text{m}^3$).

An example calculation is provided in Annex H.

7.6 Special Case: Continuous Measurement

Continuous measurement of a well's production affords the operator the opportunity to apply continuous well rate determination input into the production allocation process. The well's measured production is representative of the well parameters for that operational period. To ensure a proper accounting of the well's performance with respect to the operational conditions of the well and continuous well measurement system, the operator should routinely conduct fluid verifications (refer to 5.2.2), production verifications (refer to 5.2.3), and equipment verifications (refer to 5.2.4) and document any changes.

NOTE Documenting all changes that can impact well performance creates an audit trail for the production allocation and can be used to describe any well rate determination discrepancies.

Calculating production well volumes and rates for use in upstream measurement and allocation should follow the process outlined in Section 6, including the application of the applicable PVT and continuous measurement system material balance (e.g. inclusion of gas lift gas if warranted).

Annex A

(informative)

Types of Oil and Gas Well Tests

A.1 Oil Well Tests

A.1.1 General

Oil well tests are made for numerous reasons, and the type of test required can vary. However, these tests are generally classified as follows:

- production well test;
- potential well test;
- GOR well test;
- productivity well test.

A.1.2 Production Well Test

The production well test is the most frequently performed, periodically conducted at some specified interval, usually monthly. The test requires the measurement of gas, oil, and water. It can be used for allocation purposes in commingled production facilities or to allow the operator to keep accurate records of production from the individual wells. These are the well tests that field personnel and engineers use in analyzing well problems and predicting future well performance.

A.1.3 Potential Well Test

The potential well test is a measurement of the amount of oil and gas a well will produce during a specified period of time, under conditions fixed by regulatory bodies. The oil and gas measurements obtained from these well tests are used in assigning a producing allowable of the well.

A potential well test normally is required on a newly completed well. Other situations that can necessitate such a test are when a well is reworked into a new reservoir, when a reworked well has had its allowable cancelled, when a limited-capability well has had its allowable cancelled, and when tests are ordered by the regulatory authorities.

It is not practical to list in detail all the requirements for conducting a potential well test because all fields do not operate under the same rules. The choke size, the adjustment of rate of flow, the duration of test, and other requirements (such as packer-leakage test during potential tests on dually completed wells) vary.

A.1.4 GOR Well Test

GOR reports are required by most state authorities at periodic intervals for all wells. The GOR well test is made to determine the volume of gas produced per barrel of oil so as to ascertain whether or not a well, in making its allowable, is producing gas in excess of the permissible limit. The permissible limit may be, for example, 2000 cubic feet of gas per barrel of oil (ft^3/bbl). Wells that produce in excess of 2000 ft^3/bbl are allowed to produce that quantity of gas obtained by multiplying 2000 by the unpenalized daily oil allowable. The penalized oil allowable is then determined by the well's allowed gas production divided by its GOR.

The procedure for making a GOR well test is the same regardless of whether it is taken for a survey period or a special test between surveys. Although the equipment used in making GOR well tests is the same as that

used for a potential well test, the purpose is different because it is used to establish when the GOR exceeds the permissible limit. The volume of gas used in computing GORs and reported as being produced during a test (except tests on gas lift or jetting wells) is typically the total volume of gas produced from the well during a 24-hour test period. The total volume of gas produced through tubing and casing is generally included, except in dually completed wells.

An example would be an oil well produced 175 bbl of oil and 70,000 standard cubic feet of gas during the 24-hour test period.

What is the GOR?

$$\text{GOR} = \frac{70,000 \text{ scf}}{175 \text{ bbls}} = 400 \frac{\text{scf}}{\text{bbl}}$$

GOR behavior of wells is used in evaluating well and reservoir performance. The GOR is sometimes used as a basis for recombining oil and gas samples obtained at the surface for establishing the reservoir fluid composition. The properties of the reservoir fluid can then be determined.

A.1.5 Productivity Well Test

The purpose of the productivity well test is to determine the effects different flow rates have on the pressure within the producing zone of the well and thereby establishing producing characteristics of the producing formations. In this manner the maximum potential rate of flow can be calculated without risking possible damage to the well that might occur if the well was produced at its maximum possible flow rate. This test is helpful in designing artificial lift equipment.

The first step in conducting a productivity well test is to measure the closed-in bottomhole pressure of the well, and then the well is opened and produced at several stabilized rates of flow. The quantities of fluids are measured and recorded along with the flowing bottomhole pressure at each flow rate. The shut-in bottomhole pressure, flowing bottomhole pressures, and oil flow rates are used to plot the back-pressure curve. From this point, an absolute open flow potential of the well can be estimated when bottomhole pressures are used.

A.2 Gas Well Tests

A.2.1 General

Gas well tests are made for numerous reasons, and the type of test required can vary. However, these tests are generally classified as follows:

- production well test,
- special well test,
- back-pressure well test.

A.2.2 Production Well Test

Periodic measurement of gas, condensate, and water production are considered a production well test. For many wells, gas production is continuously metered for the individual well. This means that these wells are being continuously tested because their gas production rates and cumulative production of the gas and liquids are continuously measured. It can be used for allocation purposes in commingled production facilities or to allow the operator to keep accurate records of production from the individual wells. These are the well tests that field personnel and engineers use in analyzing well problems and predicting future well performance.

Since gas production is normally delivered above a certain specified pressure to a pipeline, it is necessary periodically to measure the wellhead flowing pressure so the time at which compressors will be required in the

system to increase the pressure above the pipeline pressure can be estimated. It is also necessary to measure the shut-in wellhead pressure because the ability of a well to produce depends upon the available pressure drawdown (difference between the shut-in pressure and flowing pressure). Periodic measurements of shut-in pressures also permit the updating of the estimated reserves. More accurate shut-in pressures are taken with a bottomhole pressure gauge rather than the pressure measured at the wellhead, although it is common practice to calculate the bottomhole pressures from the measured wellhead pressure. The wellhead pressure measured depends on the type of completion. If producing through both annulus and tubing(s) (i.e. multi-zone completion), both tubing(s) and annulus surface pressures are measured.

A.2.3 Special Well Test

There are many different types of special well tests that can be performed on gas wells. These well tests are usually performed after some significant change in well performance has been noticed. Some special well tests are required by a few government agencies. Special well testing can determine such things as well bore damage and permeability of the reservoir. Special testing of wells is very important when for economic reasons a decision is to be made whether a well is to be permanently completed or abandoned.

When a well is not produced into a pipeline, the only way to dispose of the gas produced during the test is by burning. This is a waste, and therefore some special well tests are designed such that a minimum amount of gas is wasted in getting the desired information about the reservoir and well.

A.2.4 Back-pressure Well Test

All back-pressure well test procedures involve the determination of a shut-in pressure, flowing pressure, and gas rates corresponding to the flowing pressures. The pressures can be wellhead or bottomhole. Bottomhole pressures can be measured with a pressure gauge or calculated from wellhead pressures. Back-pressure curves based on wellhead pressures are used for determining deliverability into pipelines. Back-pressure curves based on bottomhole pressures are used for determining reservoir deliverability and, in some states, for establishing allowables.

Test procedures are directed toward determining the stabilized back-pressure curve. A shut-in gas well requires a period of time before final constant (stabilized) pressure is reached. A flowing gas well requires a period of time before a final constant flowing pressure and a constant flowing rate are reached. The time required to achieve stabilized pressures and rates can vary considerably. Generally the lower the permeability of the formation, the longer it takes to achieve stabilized conditions. If long periods of time are required to attain stabilized conditions, special arbitrary rules are set up in regard to when the data should be taken. For example, the stabilized shut-in pressure can be considered attained when the rate of pressure change per day does not exceed 1 % of the shut-in pressure. Under flow conditions, the pressures can be considered stabilized, e.g. when they do not vary more than 0.1 % of wellhead shut-in pressure during a 15-minute interval.

Quite often, for economic reasons, it is not feasible to obtain stabilized flowing data. In these cases, the procedure is to obtain flowing data after a short period of time—2 hours to 4 hours—with each test being conducted for the same period of time. The multi-rate back-pressure well test of constant duration for each rate with associated data points is satisfactory for establishing the back-pressure performance of a well. If low permeability is a predominant factor, it can be necessary to run each point with a shut-in period between rates to allow the shut-in pressure to build up to essentially the initial shut-in pressure.

The several rates of flow, usually four, are then evenly distributed over the test range. If possible, the largest flow rate typically lowers the wellhead pressure significantly below the shut-in wellhead pressure (e.g. ≥ 25 %). The shut-in pressures, flowing pressures, and gas flow rates are used to plot the back-pressure curve. From this point, an absolute open flow potential of the well can be estimated when bottomhole pressures are used.

Annex B (informative)

Description of the Production Well Test System

B.1 General

The traditional production well test is characterized by the isolation of single well flow into a specialized test separator, bulk production vessel, or stock tank, whereby the acquisition of fluid measurement data during a specified time frame constitutes a production well test. In some circumstances a multiphase flow meter is used in lieu of a separator designated for testing, with the desired outcome the same as with separation-based measurement systems.

Production well testing systems are often viewed simply as a test separator, multiphase meter or stock tank operated as a standalone piece of equipment. In reality, production well testing requires a complementary and interdependent system that extends from the reservoir to the final measurement point. Failure of any component or process within this system can compromise the results of the production well test. Moreover, failure to understand the system and all of the internal physical interactions can also have a detrimental result on the outcome of the production well test. It thus becomes prudent to not only comprehend the production well testing system in its entirety, but also the individual components and mechanisms.

Figure B.1 depicts the complete production well test system, which consists of five major categories: the reservoir, the well, flow delivery, separation, and fluid measurement. Each one of these categories encompasses several components or mechanisms that can have a direct impact on the results of a production well test.

Each production well test scenario is different, and the degree to which each category influences the test can vary. However, an understanding of the entire system will allow an operator to concentrate efforts on the most important variables affecting the production well test on a well by well basis.

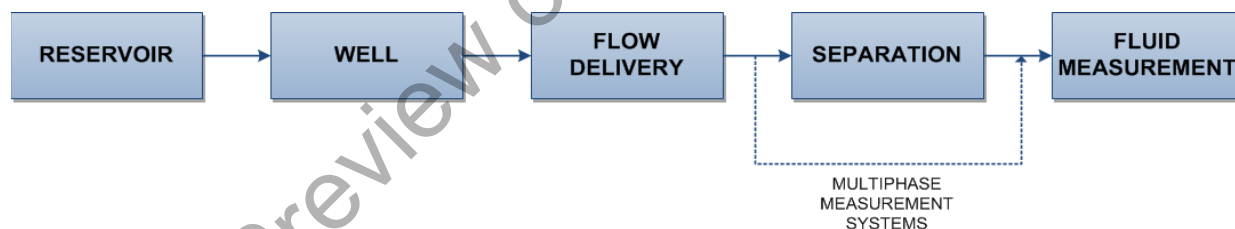


Figure B.1—The Complete Production Well Test System

B.2 Reservoir

B.2.1 General

A reservoir is a hydrocarbon accumulation contained within a porous and permeable rock formation, confined within a geological trap consisting of impermeable rock or water barriers. Reservoirs have a single natural pressure (reservoir pressure) and are classified by the major fluid type that is present in the hydrocarbon accumulation. Reservoirs can be described as:

- conventional crude oil (black oil);
- volatile oil;
- near-critical fluid (a highly volatile oil or very rich gas condensate);

- gas condensate;
- wet gas;
- dry gas.

Figure B.2 illustrates the different reservoir fluid types with phase diagrams based on pressure and temperature for each reservoir fluid.

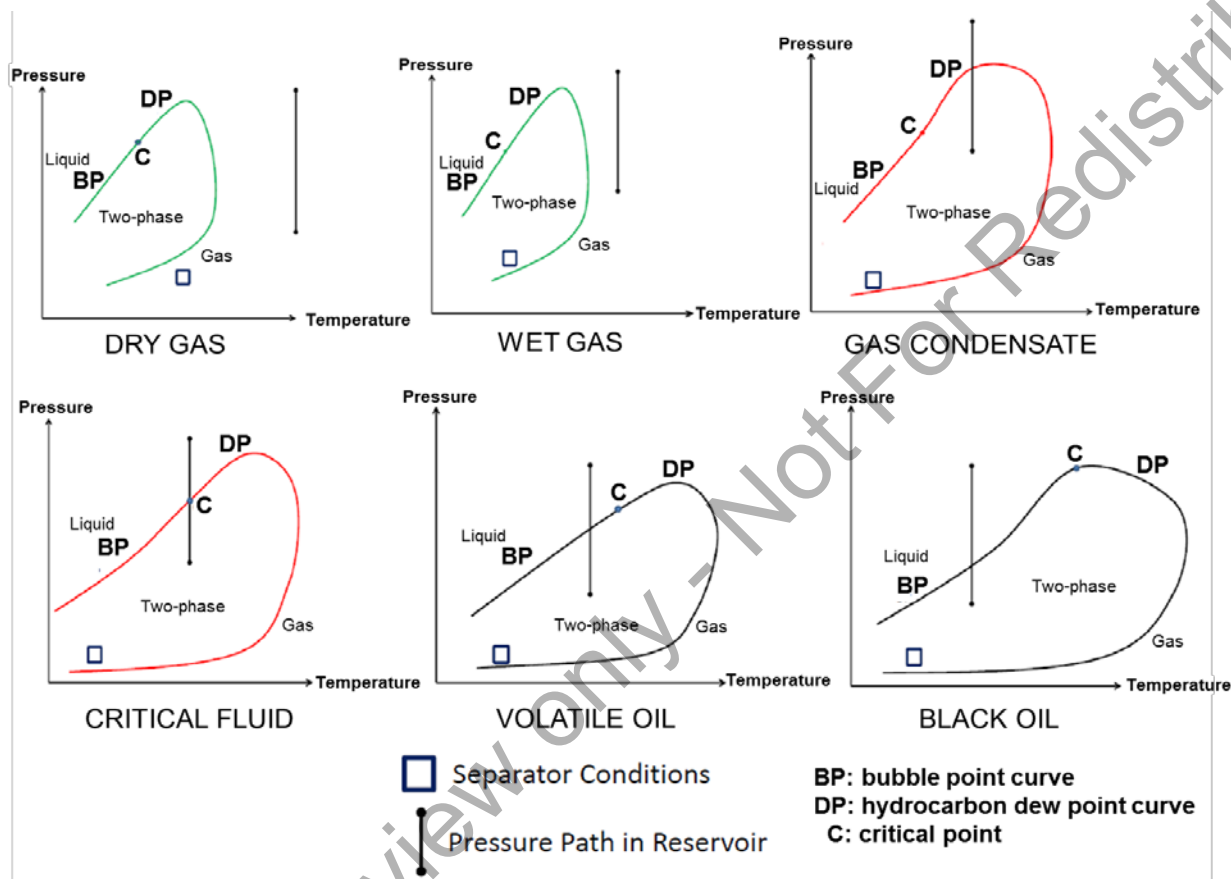


Figure B.2—Reservoir Fluid Types

Water production from a reservoir can be water vapor associated with the gas at the reservoir temperature and pressure or free water.

Depending on the type of reservoir fluid, the reservoir recovery mechanism, and the pressure depletion path followed in the reservoir during production, produced reservoir fluids can drastically change through time. The changing reservoir fluids can alter the fluid compositions, fluid properties, and flow conditions of the producing wells, and if not properly understood can negatively impact production well testing.

B.2.2 Fluid Properties and Flow Conditions

B.2.2.1 General

The type of reservoir fluids (as described in B.2.1) will typically influence the design of the production well testing infrastructure (along with all of the processing facilities). This can include size, location, material, and the choice of measurement system. Conducting production well tests benefits from a basic understanding of the applicable reservoir fluid properties and flow conditions, particularly since changes are anticipated over time.

Reservoir fluid properties of interest to production well testing can include fluid compositions, densities, and viscosities. Depending on the method of fluid measurement, production well testing operations can also utilize reservoir PVT data to develop models to characterize the fluid properties as a function of temperature and pressure. Understanding of reservoir fluid properties during production well testing can also be used to inform any production chemistry or flow assurance issues (e.g. paraffins or wax, asphaltenes, hydrates, sand) that can negatively impact the performance or result of the production well test.

Oil reservoirs above the bubble point curve and dry gas, wet gas, or gas condensate reservoirs producing above the hydrocarbon dew point curve produce single-phase fluids (refer to the “BP” and “DP” curves illustrated in Figure B.2). However, if reservoir pressures reduce to a point where either the bubble point curve or hydrocarbon dew point curve is encountered, two-phase fluid production of liquid and gas hydrocarbon within the reservoir ensues. Particularly for gas condensate fluids, two-phase fluids in the reservoir fundamentally alter the hydrocarbon composition of the fluids produced in the well and subsequently change the fluid properties. Production well testing with outdated fluid property information (e.g. fluid compositions, densities) will not yield representative production well test data. Sampling and analysis of the produced fluids is typically conducted to update the fluid property information used in the production well test, and is informed by an understanding of the phase behavior of the reservoir fluids (B.2.2.2 provides a brief overview and description of reservoir fluid classifications and phase behavior). Moreover, a more comprehensive sampling and PVT analysis (for production well test phase behavior application data) of the reservoir fluids is warranted if prior PVT analysis is no longer representative of the reservoir fluids (as can be the case in two-phase gas condensate reservoirs).

Fluid properties of the produced reservoir fluids can also change as a result of EOR mechanisms in place for the reservoir. For example, miscible gas injection alters the composition of the produced hydrocarbons.

Reservoir phase change from single-phase hydrocarbons to gas and liquids can introduce flow regimes and conditions that influence the wellbore hydraulics, which in turn can influence the production well test. Situations can arise where two-phase flow in the near wellbore region leads to two-phase flow in the wellbore, with possible well slugging or liquid loading (particularly for gas wells). Previously steady producing wells can exhibit drastically different characteristics and can be difficult to stabilize for production well testing. In scenarios such as this, production well testing on stabilized well flowing conditions might need to be modified to “representative” well flowing conditions.

NOTE “Representative” flow conditions refer to flow conditions that are representative of normal well operating conditions (i.e. the observed well slugging or cyclical behavior during the production well test is similar to that observed during normal operations).

An additional reservoir flow condition to consider results from low permeability, or “tight-gas” reservoirs where steep decline rates in production typically occur. Production well testing earlier in the life of the well can be more beneficial than later in well life, as frequent production information is more important early in well life to accurately represent the decline of the well. Furthermore, some production wells are operated in a cyclical manner, whereby the wells are periodically shut-in to allow an increase of reservoir pressure prior to the next well production cycle. Well production declines and dynamic GORs are apparent in these cases and can impact production well testing operations of cyclical wells.

B.2.2.2 Reservoir Phase Behavior

From a technical perspective, fluids are classified into four phase regions:

- liquid;
- gas or vapor;
- dense phase or supercritical fluid;
- two-phase (liquid and gas).

The liquid phase region has a definite volume but no definite shape. It will assume the shape of the container in which it is placed but will not necessarily fill that container. The liquid phase region exhibits low fluid compressibility and high mass density values.

A gas or vapor phase region has no definite volume or shape and will completely fill the container in which it is placed. The gas phase region exhibits high fluid compressibility and low mass density values.

Assuming a constant composition, the mass density of a gas is lower than the mass density of a liquid.

A dense or supercritical phase region has no definite volume or shape and will completely fill the container in which it is placed. The dense phase region is in the single phase and exhibits high fluid compressibility and high mass density values. These values vary as a function of the fluid's pressure and temperature values. The dense phase region is defined as the region where pressure exceeds the critical value (i.e. critical pressure).

The two-phase region has no definite volume or shape and will completely fill the container in which it is placed. The two-phase region contains fluid in both gas and liquid states simultaneously.

Referring to Figure B.3, the following statements apply.

- The bubble point curve is the curve separating the liquid region from the two-phase region. The bubble point curve represents the true vapor pressure (TVP) for a liquid. The equilibrium vapor pressure (P_e) is the TVP at a specified temperature on the bubble point curve.
- The hydrocarbon dew point curve is the curve separating the dense phase and gas regions from the two-phase region for a fluid.
- The two curves (bubble point and dew point) intersect at the fluid's critical point. These curves define the two-phase envelope for the fluid (simultaneous presence of liquid and gas).
- The phase envelope defines the region between two-phase and single-phase fluids. The phase diagram may be plotted as a function of pressure and temperature or as a function of pressure and enthalpy. For multiple component fluids, the two-phase envelope varies as a function of pressure, temperature, and composition.
- Critical point is the pressure (P_c) and temperature (T_c) at which the properties of the bubble point curve and dew point curves intersect.
- Cricondenbar is the maximum pressure of the phase envelope. For single component compositions, or pure fluids, the cricondenbar and the critical pressure are identical.
- Cricondenthem is the maximum temperature of the phase envelope.
- Retrograde region is the area inside the phase envelope where condensation of liquid occurs by lowering pressure or increasing temperature. For single component compositions, or pure fluids, a retrograde region does not exist.

Gas reservoirs are classified as dry, wet, or condensate depending on the path of depletion (pressure and temperature). For dry gas reservoirs, no hydrocarbon liquids are formed in the reservoir, wellbore, flowline, or production processing facilities because the path of depletion is outside of the two-phase envelope. For wet gas reservoirs, no liquids are condensed in the reservoir, but may fall out in the wellbore, flowline, and production processing facilities because the pressure and temperature fall within the two-phase envelope. For gas-condensate reservoirs, as the reservoir pressure is reduced, retrograde condensate forms in the reservoir when the reservoir pressure and temperature fall below the dew point line.

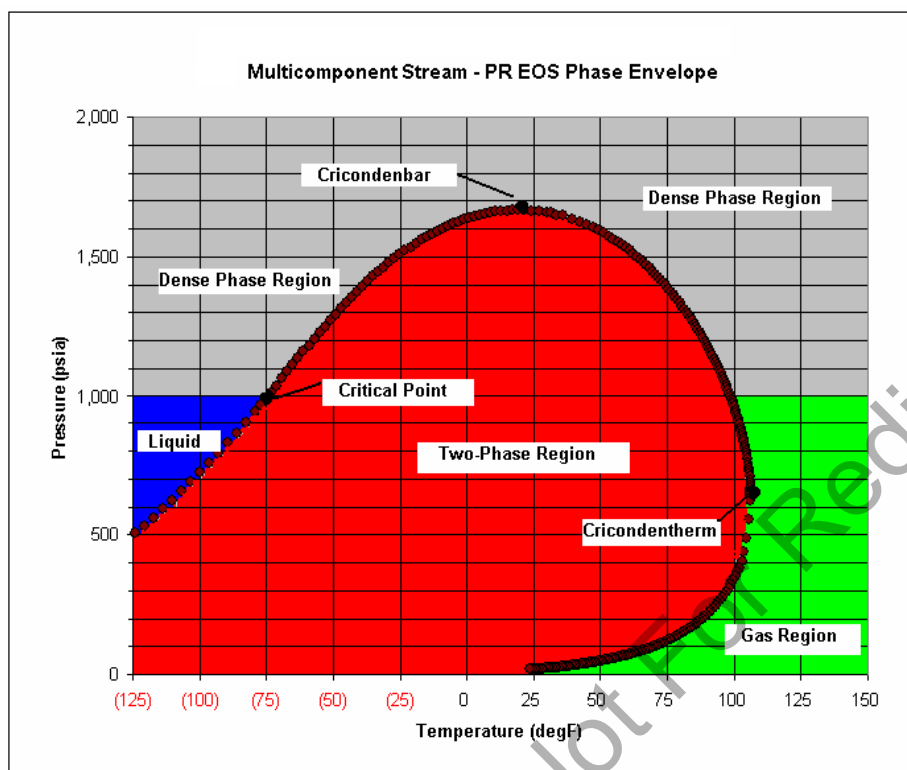


Figure B.3—Example Hydrocarbon Phase Envelope

B.2.3 Reservoir Recovery Mechanisms

B.2.3.1 General

The driving forces (both naturally occurring and artificially created) that combine to move fluids in a reservoir are referred to as recovery mechanisms. For oil reservoirs, the volume of oil recovered is governed by the recovery mechanism. Production well test data are used to understand these driving forces and inform decisions to initiate programs to effect the recovery mechanisms of a reservoir that can result in large economic gains.

There are four distinct natural recovery mechanisms, primarily for oil reservoirs:

- solution-gas drive;
- gas-cap drive;
- water drive;
- gravity drainage.

These recovery mechanisms can all be applicable to gas reservoirs. However, the predominant natural driving forces are typically a gas-cap drive (for gas reservoirs containing gas and liquid hydrocarbons only) and combination water gas-cap drive (for gas reservoirs containing water along with the gas and liquid hydrocarbons).

B.2.3.2 contains descriptions of each recovery mechanism and examples where production well testing can provide information on recovery mechanisms used to inform reservoir management strategies.

Artificial recovery mechanisms consist of injecting fluids into a reservoir as a method of improving recovery of hydrocarbons. These fluid-injection projects are generally referred to as EOR. EOR methods are divided into two broad categories: miscible processes and thermal processes.

Miscible processes include:

- waterflooding;
- chemical injection (e.g. surfactants, alkaline or caustic);
- gas injection (e.g. CO₂, produced gas, miscible gas).

Thermal processes include:

- steam flooding;
- cyclic steam injection;
- fire flooding or in situ combustion.

The injection of fluids into the reservoir as part of an EOR project can alter the fluid properties of production wells (e.g. miscible gas injection, refer to B.2.2.1). Fluid sampling might be required to update fluid property information used in production well testing. In addition, water production can greatly increase (such as during an EOR waterflood), thereby increasing the water observed during a production well test.

Production well testing might also require periodic sampling of reservoir fluids for EOR data, such as chemical tracers used in evaluating reservoir EOR performance. Consideration for EOR sampling requirements is useful in the production well testing process, as accurate production well test data along with EOR evaluation data can be leveraged to increase reservoir recovery.

Depending on the reservoir recovery mechanism and any applied EOR processes, a producing well can follow a production trajectory that drastically changes over the life of the well. A production well test system maintained and operated in a manner that reflects the changes in the reservoir, and the subsequent well production over time, will provide the best opportunity at representative data.

B.2.3.2 Recovery Mechanism Descriptions

B.2.3.2.1 Solution-gas Drive

In this type of recovery mechanism, the oil is moved to the producing wells through the energy of the gas dissolved in the oil (refer to Figure B.4). As a well is produced, the pressure around the wellbore is reduced below the pressure in the formation. The loss of pressure causes gas to come out of solution (reservoir pressure falls inside the two-phase envelope), and this expansion of gas propels oil and gas to the wellbore. Such wells are usually recognized by little or no water production and an increasing GOR. This type of recovery mechanism is very inefficient, yielding recoveries generally less than 25 % of the oil originally in the reservoir.

Production well test data can indicate solution-gas drive very early in the producing life of the reservoir, when GORs are increasing and pressures around the wellbores are decreasing. Early detection of this type of very inefficient drive can permit the installation of a pressure maintenance program that can more than double the recovery from the reservoir.

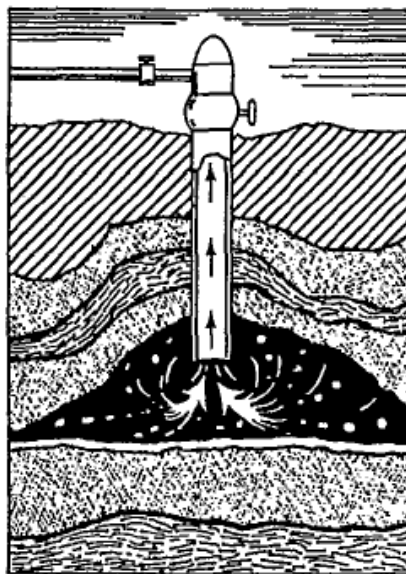


Figure B.4—Solution-gas Drive

B.2.3.2.2 Gas-cap Drive

If a quantity of free gas overlies oil in a reservoir, this is called a “gas cap.” Recovery is aided by the gas cap expanding into the oil zone as oil is produced, thus tending to maintain reservoir pressure (refer to Figure B.5). Gas-cap drive is generally more efficient than solution-gas drive, and oil recovery can be as high as 40 %.

Wells producing from this type of reservoir behave much like those in a solution-gas drive, with the exception that productivity does not decline as rapidly.

If gas production is not accurately reported by accurate production well testing, wells might be drilled into a gas cap unknowingly. This is an undesirable situation, because the gas cap ordinarily must be conserved as long as commercial oil production is possible. By not producing the gas cap, energy is conserved, and the recovery of a greater amount of oil is possible.

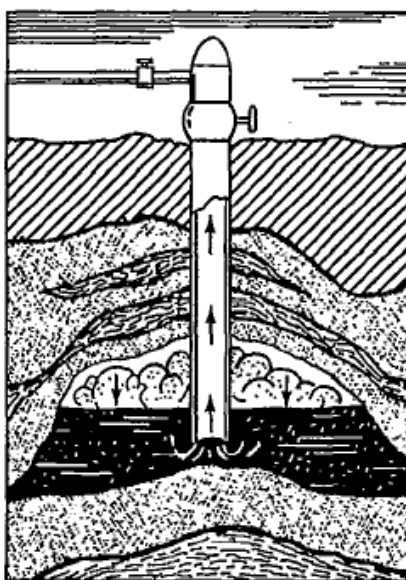


Figure B.5—Gas-cap Drive

B.2.3.2.3 Water Drive

When oil is recovered through water drive, water displaces the oil as it is withdrawn from the reservoir (refer to Figure B.6). The efficiency of this mechanism varies greatly. Recovery may be as high as 80 % of the oil-in-place, but is sometimes lower than 40 %. Water percentages increase in wells produced in this manner and water production ultimately is high.

Production well test data can indicate water moving up-dip in the reservoir. Without sufficient production well testing, the water movement may not be detected, and in such circumstances, a waterflood might be commenced with the same results as in solution-gas drives. If water production is not reported or sufficiently monitored, unprofitable wells might be drilled into the water-out portion of the reservoir.

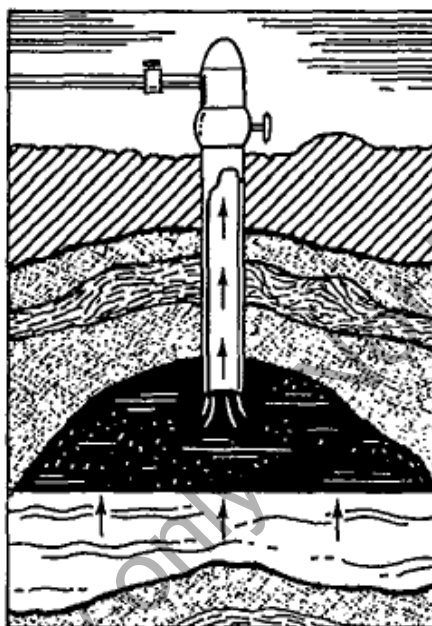


Figure B.6—Water Drive

B.2.3.2.4 Gravity Drainage

In a reservoir, gravity forces can work to separate oil and gas as the reservoir is depleted, with gas going to the top of the structure and oil going to lower portions (refer to Figure B.7). This type of mechanism is highly efficient, with oil recoveries of 70 % sometimes obtained.

Production well test data can indicate that wells high on the structure go to gas and the wells low on the structure remain low GOR producers. The progress of the down-structure movement of oil can be traced by noting when wells go to gas. These observations permit a calculation of recovery efficiency, which in many cases is so high that it would not pay to waterflood. Without accurate production well testing, the change of the GORs of individual wells might not be reliably determined. A wrong conclusion might be reached that could initiate an expensive waterflood that would not increase oil recovery.

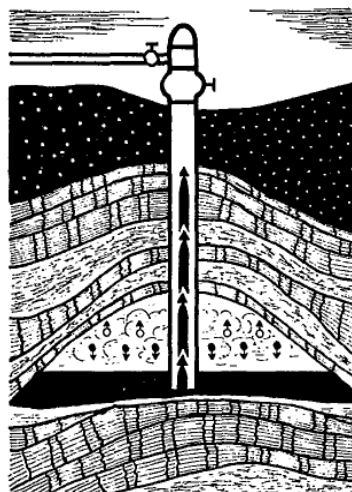


Figure B.7—Gravity Drainage

B.3 Well

B.3.1 General

Oil and gas production wells can be drilled, completed, and produced in a variety of ways. Wells can have vertical, deviated, or horizontal trajectories and various completion types across multiple downhole production zones, with multiple laterals or production strings. Wells vary in location from onshore to offshore (topsides and subsea) and are operated and maintained according to the reservoir, well, and facility constraints of the system.

Depending on the type of well and the fluids produced, and the production environment, various factors can influence production well testing. Wellbore hydraulics, well flow patterns, well workovers, and chemical treatments can all introduce dynamic or altered fluid flow behaviors that can significantly impact the results of a production well test.

B.3.2 Wellbore Hydraulics

The pressure differential between the reservoir and the bottomhole of the wellbore (pressure drawdown) creates the motive of force for fluid flow from the reservoir into the well. Fluid flow hydraulics up the wellbore and into the production system are a function of numerous variables, including well trajectory, completion type, pressure, temperature, fluid type, and any deployed artificial lift methods.

Production well testing operations are typically interested in any change that can alter the wellbore hydraulics and thus alter the performance of the well. Wellbore configuration changes (e.g. a new side-track or lateral drilled in an existing well), new completions (e.g. a velocity string to increase vertical lift or opening of a new production zone downhole), and changes in reservoir pressure or fluid properties all contribute to alter the fluid flow environment within the wellbore. This in turn affects the wellbore hydraulics and flow performance of the well.

Depending on the completion type, there might be drawdown limitations imposed on a producing well (e.g. to minimize water breakthrough or sand production). Choke settings can also influence wellbore hydraulics, particularly when choke setting adjustments are necessary to re-establish wellhead or downhole pressures to values similar to normal producing pressures after moving wells in and out of production well test systems. These choke changes can temporarily introduce scenarios where the wellbore hydraulics create transient dynamic flow regimes that require time to stabilize. The pre-stabilization period prior to a production well test can be greatly influenced by any temporary wellbore hydraulic-induced instability.

Cyclical changes of producing rate and well pressures can also result from liquid accumulating in the wellbore and then periodically unloading. This problem usually occurs in low producing gas wells with high liquid–gas ratios and is indicated by wide variations in observed pressures. This can be alleviated with higher production rates or the use of artificial lift.

Artificial lift methods are generally used to either stabilize wellbore hydraulics (in the case of slugging wells) or create the motive force for lifting production fluids up the wellbore. These methods are divided into two broad categories: pumps and immiscible fluid displacements.

Pumping methods include:

- rod pumping;
- plungers;
- electrical submersible pumping (centrifugal or screw type);
- subsurface hydraulic piston pumping;
- subsurface hydraulic jet pumping (oil or water-based power fluid).

Immiscible fluid displacement methods include:

- gas lift.

Artificial lift fluids introduced into the production well (e.g. power fluid or gas) are generally at volumes sufficient to warrant inclusion in the accounting of the production well test.

B.3.3 Well Flow Patterns

Well flow patterns are closely related to wellbore hydraulics in that both are influenced by pipe geometry, fluid types, pressures and temperatures, and any deployed artificial lift methods. Whereas wellbore hydraulics define flow in the wellbore, well flow patterns are the observable well flow regime at the measurement point.

A separate distinction between wellbore hydraulics and well flow patterns at the measurement point does need to be made, as distances between the well and the measurement point can create scenarios where wellbore and measurement point flow regimes are not similar. For example, minimal or minor wellbore slugging can manifest into severe slugging at the measurement point. Conversely, very stable flow conditions at the well can be observed at the measurement point as slugging or erratic, if flowline geometries and topologies between the well and the measurement point introduce hydraulic conditions favorable for dynamic flow behavior (e.g. offshore-riser-induced slugging). In addition, production well test separators can operate in a manner that induces flow variability at the measurement point (refer to B.5.4).

The flow regimes that define well flow patterns range from single-phase hydrocarbon flows (oil or gas) to multiphase mixtures of hydrocarbon and water. Flow regimes vary depending on operating conditions, fluid properties, flow rates, and the orientation and geometry of the pipe through which the fluids flow. The transition between different flow regimes may be a gradual process or instantaneous.

As mentioned in B.2.2.1, reservoir fluid properties and flow conditions can have a large impact on the observable well flow pattern. Evaluating and understanding well flow patterns prior to and during production well testing thus becomes important. This allows both an understanding on how to measure the flow (particularly important for measuring multiphase flow) and what activities can be evaluated to mitigate potentially difficult well flow patterns for production well testing (e.g. efficient test separator operations).

NOTE For detailed information on multiphase flow regimes, the operator is referred to API *MPMS* Ch. 20.3.

Well flow patterns can vary from intermittent slugging to more reproducible volumetric cycles. On a broader timescale, well flow patterns can be interpreted as the cyclical nature of some wells (refer to B.2.2.1). Increased water production (liquid production in general, for gas wells) can alter the flow hydraulics in the wellbore or flowline, leading to slug flow regimes that can adversely affect production well test stabilization periods.

Other factors that can impact well flow patterns relate to solid (sand) production from the well or any production chemistry or flow assurance issues such as hydrate formation, paraffin or wax accumulation, asphaltene precipitation, or scale deposition.

B.3.4 Well Workovers

Well workovers are typically implemented to either increase the economic recovery of a reservoir (increased access to reserves, e.g. perforation of a new zone or drilling of a side-track lateral) or resolve a wellbore constraint (e.g. downhole scale) that is inhibiting production. In either case, the resultant production from the well can be significantly different than the previous production. It is essential that production well testing is always performed in a manner that is aware of any previous well workovers, with recognition for the potential impact of changed well performance.

Well workovers typically include:

- wellbore cleanouts (e.g. scale, asphaltenes, paraffins);
- new perforations;
- recompletions (e.g. new tubing, velocity strings);
- side-track drilling, new laterals;
- artificial lift (e.g. new systems or changeouts).

Well workovers can alter the wellbore hydraulics and well flow patterns previously discussed. Depending on the type of workover, produced fluid properties and phase behavior can change and influence the production well test on the worked-over well.

NOTE Well workovers are usually a motivation to retest the producing well, as there is an expectation that flow rates will have changed.

B.3.5 Well Chemical Treatments

Chemical treatment of producing wells is often necessary to mitigate or prevent production chemistry or flow assurance threats to production. Additionally, chemicals might be introduced to aid in gas, oil, and water separation or reduce the effect of biological organisms. Depending on the chemical treatment program and the degree to which it is implemented, produced fluid properties and well flow patterns can change. It is important that production well testing is performed with an awareness of the various chemical treatment programs and the potential impact on produced well flow.

Typical producing well chemical treatment programs can include:

- anti-flocculation (paraffin or wax);
- biocides or fungicides (bacteria or fungus);
- methanol (hydrates);
- de-emulsifier (water–oil separation);

- foam breaker (liquid foaming);
- pour point suppressant (crude oil);
- scale inhibition (scale);
- corrosion inhibitors (internal corrosion);
- oxygen scavengers (corrosion);
- H₂S treatment.

B.4 Flow Delivery

B.4.1 General

The delivery of reservoir fluid flow from the wellhead to the production processing facilities and production well test measurement point (i.e. separator, multiphase flow meter, or tank battery) requires the use of flowlines that can be extensive and varied. For subsea applications, multiple wells can be commingled into single subsea flowlines (e.g. subsea tie-back), where flowline elevation changes and long lengths can introduce challenging flow regimes for both production processing and measurement.

Production well testing operations are concerned with the isolation of well flow between the well and the measurement point. The dynamics of flow between the well and the measurement point can represent one of the most challenging aspects of production well testing, and careful evaluation is usually important when situations are present that can influence well flow patterns (refer to B.3.3).

B.4.2 Flow Isolation

Isolation of well flow during a production well test is important such that the measured well flow is representative of the well under test and does not include flow from other sources. Flow isolation is imperative to production well testing, and it is important to verify that the production well testing system is capable of isolation of single well flow. This can include zero-rate testing of the production well testing system (i.e. a no-flow test of the system to ensure no volumetric flow is measured) where flow diverter valves to a well test header are closed and the measurement system is monitored for a flow rate. Depending on the flow delivery architecture between the well and the measurement point, other system checks can be necessary to evaluate the integrity of isolated flow.

In some circumstances, production wells do not have the energy to flow in isolation to the measurement point. In particular, this can be the case for low rate wells or small wells flowing in large subsea tie-back flowlines. It can also be the case for wells that exhibit severe slugging or oscillations at the measurement point such that flow stabilization is impossible or slugging flow is detrimental to the production measurement system equipment. In these circumstances, isolating the well for a production well test is not possible, and the production well test is conducted as a by-difference production well test.

B.4.3 Flowline Dynamics

Fluid flow in flowlines can be distributed in a variety of flow regimes that result in well flow patterns exhibiting numerous characteristics. Flow regimes for hydrocarbon liquid and gas systems (including water) are generally defined by the following variables:

- gas and liquid flow rates;
- flowline diameter and inclination angles (terrain effects);
- physical properties of the fluids (e.g. densities, viscosities, surface tension);

- transient effects (e.g. valve openings or closures);
- flowline pigging.

When the measurement point is some distance away from the producing well (e.g. subsea tie-back), the flowline can act as a liquid accumulator, permitting gas slip to increase along with increased liquid slug development and frequency. Flowline elevation and geometry changes can amplify this effect and adversely impact the well flow pattern (refer to B.3.3).

In the absence of transients effects, a steady-state (or quasi steady-state in the case of slugging flow) flow regime will eventually develop that can still include intermittent or variable flow. Additionally, localized accumulation of liquids (liquid hold-up) or gas (gas line pack) can be created in the flowline. In cases where the measurement point (e.g. test separator or multiphase flow meter) is located essentially at the wellhead (e.g. onshore or dry-tree offshore installations), liquid hold-up and gas line pack are generally not a major influence on production well test results. However, in cases where there is a substantial distance between the wellhead and measurement point (e.g. remotely located separators, long subsea tie-backs), liquid hold-up or gas line pack can affect the production well test results. Particularly during a transient period in a long flowline (well alignment, valve opening or closure), liquid hold-up is a variable that can have a very long period, leading to extended time before the flow reverts to some equilibrium value (with some characteristic periodic variability). This time can be on the order of days, depending on the length and topology of the flowline.

Flowline dynamics can also be influenced by production chemistry and flow assurance threats in the flowline and can include:

- flocculation (wax formation or paraffin deposition);
- asphaltene deposition;
- scale deposition;
- gas hydrates (particularly for high-pressure gas wells);
- flowline corrosion;
- flowline rouge;
- erosional effects due to flow velocities (particularly gas) or entrained particulates (primarily sand).

The formation and deposition of paraffins, asphaltenes, scale, hydrates, or corrosion by-products can make it difficult to obtain reliable production well test data and might require equipment changes or chemical additions to eliminate the problem. Equipment changes might include the necessary addition of heaters upstream of a high-pressure separator or the use of a low-temperature separator (e.g. for hydrate mitigation). Chemical treatments as described in B.3.5 might also be administered.

B.5 Separation

B.5.1 General

The challenge of measuring multiphase well flow has traditionally been addressed with phase separation of the flow into single-phase gas and liquids (or single-phase gas, oil, and water) with the application of single-phase meters or tank gauging for fluid measurement. Separators of various sizes and types are designed and operated to achieve the necessary phase separation, and to a large extent can affect production well testing operations. The separator technology, size, operation, and efficiency all contribute to the relative quality of the single-phase fluids available for single-phase flow measurement or tank battery volumetric measurement.

NOTE The application of multiphase flow measurement systems precludes the use of separators, as the desire to separate the fluids prior to measurement has been removed. Alternatively, some partial separation systems (refer to B.5.2) can use multiphase meters as the source of measurement on the separated flows.

B.5.2 Separator Technology

The fluid properties and flow rates of the produced reservoir fluids, along with operating process conditions, typically inform the design of the separation system used in production well testing including type, size, and to a certain degree location. Production well testing separators can be either bulk production vessels or separators dedicated for use only in well testing and can be designed and operated as two-phase or three-phase vessels. Two-phase separators separate multiphase well fluids into two discrete phases of liquid and gas at the operating pressure and temperature of the separator, where three-phase separators add hydrocarbon liquid and water separation. For either separation approach, the multiphase flow is separated into single-phase flows that are appropriate for measurement by single-phase flow measurement devices (or tank level measurement).

Separators work on the basis of gravity or centrifugal segregation of the produced fluids. In gravity separation, liquid droplets settle out of a gas phase if the gravitational force acting on the droplet is greater than the drag force of the gas. Similarly, water droplets will separate from the oil due to the density differences in the two fluids. In cyclonic or centrifugal separation, centrifugal forces separate the fluid phases based on the difference in momentum (as relates to density) of the fluids.

Separation vessels can be either vertical or horizontal and typically consist of five major sections:

- inlet device;
- gas gravity separation section;
- liquid gravity separation section (some three-phase separators include a weir to skim the crude oil from the free water);
- mist extraction section;
- control system (liquid level control, liquid dump and back-pressure valve, gas back-pressure valve, safety relief valve).

NOTE For more information on separators used in liquid/gas and gas, oil, and water separation, refer to API Specification 12J^[7].

Bulk separators and test separators might have automated control systems, with sophisticated liquid level, flow, and back-pressure control, or the separators might be manually controlled. This is an important distinction, and useful to know and understand during production well testing operations.

Depending on the infrastructure and operation, there can be different variations of production separation vessels used for production well testing. Horizontal separators are generally used for liquid dominant production (oil wells), and vertical separators are generally used for high gas producers (gas wells). Heater-treaters can be used in lieu of separators and can be placed in series after free-water knockout vessels if necessary.

NOTE Heater-treaters are generally used where the addition of heat is required to aid in the separation process. Free-water knockout vessels are utilized for removing excess water prior to separation of the remaining bulk fluids in the heater-treater. In some low gas production or low pressure cases, propane blankets (an addition of gas into the treater) can be added to provide pressure support for the separation process.

Some oil installations utilize tank batteries for hydrocarbon liquid collection and storage following production separation, or multiple separation vessels in series to produce stabilized crude oil prior to measurement. Some gas installations utilize two separators (high- and low-pressure separators), low temperature separators,

and fractioning towers (i.e. stabilizers) that can all be included in the production well test system. Regardless of the vessels involved or the pressure reduction of the system, the goal of phase separation suitable for single-phase measurement in production well testing remains the same.

NOTE Separation can be achieved through the use of portable separators, which can be skid mounted in a variety of sizes for temporary use.

Not all separation systems available for use in production well testing are designed and operated for complete phase separation of the produced reservoir fluids. Some systems consist of partial separation technology, where gassy liquids and wet gas are the intended phase splits. Separation vessels using both gravity and centrifugal forces can be used in partial separation systems, with the intent to maximize bulk separation as much as possible without the size or cost of a traditional separator. Partial separation systems tend to be small or compact, and are usually seen as advantageous in this regard (e.g. cyclonic).

B.5.3 Separator Size

Separator design and configuration is generally based on three parameters:

- gas capacity;
- liquid capacity;
- operability.

Gas capacity determines the cross-sectional area necessary for gravitational force to remove the liquid from the gas, while liquid capacity determines the volume required to provide adequate residence time to de-gas the liquid or to allow immiscible liquid phase (free water and oil) to separate. Operability factors include the ability of the separator to handle solids, unsteady flow, liquid slugging, wax (paraffins), hydrates, scale deposition, well flow rate ranges, pressure, temperature, and fluid compositions.

Test separators are typically sized to separate liquid (oil and water) and gas phases from single producing wells, where bulk separators are typically designed to separate large amounts of produced fluids from several wells simultaneously. If production well tests are conducted in separation vessels not properly sized for the specific well flow, separator efficiency can be compromised (refer to B.5.4), leading to limitations in the ability to measure the outlet fluid flows (refer to B.6.2) along with nonrepresentative well flow.

B.5.4 Separator Efficiency and Operation

Separator efficiency is directly related to the residence time necessary for phase separation. Several factors influence the residence time and include:

- separator size;
- fluid flow rates;
- fluid properties (e.g. density, viscosity, emulsion forming tendencies);
- temperature and pressure;
- sand or particulate fill in the separator;
- separator liquid level;
- separator operability (liquid level control, temperature and pressure control).

Residence times are generally on the order of minutes, with three-phase separator residence times typically longer in comparison to two-phase separators. Residence times can vary widely depending on the factors

previously mentioned, and are not easily manipulated once process conditions are set (vessel size, well flow rates, fluid properties). However, for production well testing, some latitude on the residence time can be gained through the use of chemicals (e.g. de-emulsifiers or emulsion breakers) or heat. Moreover, periodic vessel cleaning is typically implemented if sand production is significant.

NOTE Some separator designs include sand jetting or sand cleanout systems for periodic removal of the sand, typically through the water outlet of a three-phase separator.

Production well testing separators operate in the two-phase envelope of the produced reservoir fluids, with the gas outlet flow at temperature and pressure corresponding to the hydrocarbon dew point curve and the liquid (oil) outlet flow at temperature and pressure corresponding to the bubble point curve (as shown in Figure B.8). Operation of the production test separator with liquid or gas outlet temperatures and pressures within the two-phase curve can introduce two-phase conditions at the separator outlets if not operated within the separator operating envelope (gas carry-under, liquid carry-over), which can negatively impact flow measurement (refer to B.6.2).

To handle flow variations with incoming flow rates, separator liquid level sensors and control valves are typically included in the design and operation of a production well test separator. The liquid level sensors and separator controls are critical for safe, efficient, and effective separator performance and efficiency. In particular, the sensors and valves can minimize entrained liquids in the gas outlet and entrained gas in the liquid outlet, which can adversely affect flow measurement performance (refer to B.6.2).

NOTE Liquid sensors in combination with a dump or back-pressure control valve on the separator liquid outlet and a control valve on the separator gas outlet can work in conjunction to adjust the separator response to variable incoming flows. For example, if a separator fills with a slug of liquid carrying little gas, then the gas outlet control valve closes and the liquid control valve opens to increase the rate of liquid discharge.

Separation efficiency and operation is especially important when well fluids form emulsions. Emulsions that cannot be separated through normal retention time may require additional heat and/or chemicals (e.g. de-emulsifiers) for sufficient separation. This can impact production well test operations, particularly for production well test systems that test several wells and might need to adjust between the various producing scenarios.

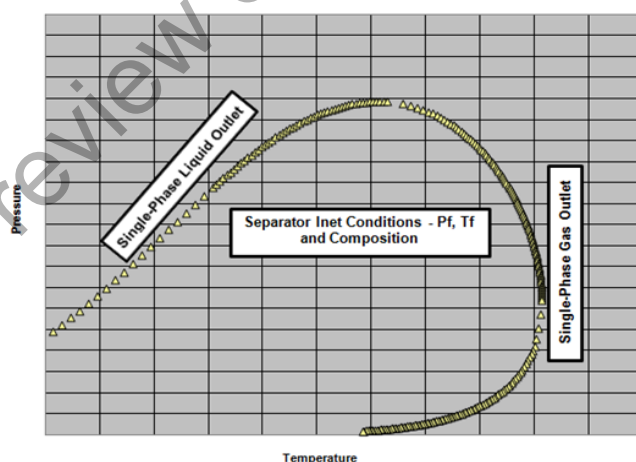


Figure B.8—Example Phase Envelope for Separator Operations

B.6 Fluid Measurement

B.6.1 General

Production well testing fluid measurement systems are used for determining gas, oil, and water volumes to within acceptable uncertainty tolerances for use in production allocation measurement. The challenges

inherent to production well testing fluid measurement include changing well flow regimes and fluid properties, and operational constraints that create a potential for dynamic measurement conditions.

Fluid measurement in production well testing is a combination of flow metering or tank gauging, fluid quality (sampling and analysis), and the application of phase behavior (PVT properties). Production well testing systems can include the use of various measurement systems for single-phase and multiphase fluids, along with sampling equipment to obtain information about the produced flow. In obtaining fluid flow information during a production well test, it is imperative that there is a full accounting of all fluids entering (e.g. gas lift gas, power fluid) and exiting (final gas, oil, and water outlets) the production well testing system.

NOTE Chemical additives are not generally accounted for during a production well test. Gas lift gas and jet pump power fluids are usually introduced at high enough volumes such that the material balance of the system would be significantly impacted if those volumes were not accounted for. Chemicals such as methanol or corrosion inhibitor are not dosed at volumes significant in comparison to the well flow rates.

B.6.2 Flow Metering

Metering systems used in production well testing consist of:

- single-phase meters (on single-phase fluids downstream of separation);
- online water determination devices (on oil and water liquid flows);
- multiphase flow meters (on multiphase full well flows).

There are several types of single-phase flow meters, multiphase flow meters, and online water determination devices that are available for use in production well testing. It is important that metering systems be capable of measuring the flow within the operator's acceptable tolerances for flow measurement. This can include highly variable flow rates (in relative comparison between wells with different flow rates that are tested with the same production well test system) and dynamic flow conditions due to the various fluid properties and flow regimes at the measurement point.

B.6.3 Tank Measurement

In some production well testing applications, the measurement of produced oil and water is accomplished in stock tanks following separation. The tank liquid measurement systems used in production well testing consist of:

- manual tank gauging;
- automatic tank gauging.

There are several methods of manual tank gauging and types of automatic tank gauging systems available for production well testing. It is important that manual tank gauging methods or automatic tank gauging systems be capable of measuring the liquid volume within the operator's acceptable tolerances for volumetric measurement. This also includes free water and S&W determination.

B.6.4 Fluid Quality

Fluid quality encompasses the sampling and analysis of produced reservoir fluids that is necessary for the application of flow measurement in production well testing and generally can include:

- fluid compositions;
- fluid densities;
- fluid viscosities;

- B_o , B_g , B_w , R_s , and r_s ;
- watercut.

Fluid quality systems used in production well testing consist of:

- sampling systems;
- online water determination devices (on both oil–water liquid flows and multiphase flows).

NOTE Additional sampling and analysis for reservoir, production chemistry, or flow assurance reasons can be conducted during sampling and analysis activities for production well testing and used to inform the operator on potential changes or threats that might influence production well test operations (refer to B.2.2.1).

The specific fluid quality requirements for the production well test system metering depends on the choice of metering device (single-phase or multiphase), the fluid under measurement (gas, oil, oil–water, water, multiphase), and the extent that fluid property information is required (e.g. fluid property information might be required over a range of operating temperatures and pressures, thus requiring PVT sampling and analysis). Obtaining representative fluid information to address the fluid quality requirements often contributes the highest uncertainty in the flow measurement result, due to the challenges inherent to sampling and analysis of production fluids in the upstream environment. Additionally, it is important that online water determination devices be capable of measuring the full range of expected watercuts.

Production well testing might also incorporate additional fluid quality requirements separate from the requirements for the flow metering system. In this case, coordination of sampling and analysis activities is useful in maintaining consistency in both data collection and results.

NOTE For more information on fluid property requirements for single-phase meters, refer to the applicable single-phase meter API standard or manufacturer recommendations. For multiphase flow meters, refer to API *MPMS* Ch. 20.3 or manufacturer recommendations.

B.6.5 Phase Behavior Application

Phase behavior is the PVT characterization of the physical changes reservoir fluids undergo through a production process prior to becoming stabilized oil and gas. Production well testing flow measurements are generally obtained on unstable fluids with the flow metering results calculated at the measurement point process conditions (i.e. temperature and pressure). However, reporting production well test results typically requires conversion to standard conditions. To accomplish this conversion, an application of phase behavior to the line condition result is applied.

NOTE Depending on the production well test system equipment, oil and gas may be completely separated to standard conditions, thus negating the need for an application of phase behavior.

Annex C (informative)

Example Analysis for Establishing Production Well Test Duration During Nonstable Flow Conditions

NOTE The following is merely an example for illustration purposes only. It is not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

C.1 General

Flow variability at a production well test measurement point (i.e. through a flow meter) generally leads to nonrepresentative production well test volumes if sufficient data are not collected to “average” out the flow variability. Sources of flow variability at the measurement point typically include the following:

- slugging or dynamically unstable wells;
- slugging or dynamically unstable flowlines or risers;
- artificial lift systems that produce a pulsed flow output from the well (e.g. plungers or rod pumps);
- inefficient or improperly operated separator level or interface control;
- batch “dump” cycles through the meter.

In these cases, production well test data can be evaluated to establish a production well test duration using start and stop times that enable sufficient data collection to “average” out the flow variability. An example process is provided in this annex.

C.2 Procedure

- 1) *Characterize the Flow Variability.* Many variable flow conditions at the measurement point exhibit periodicity and repeatability that can be useful in determining production well test duration. For example, a separator dump cycle every 10 minutes or a well producing a liquid slug every 20 minutes can be observed as a periodic rise and fall in measured volume. Characterizing the flow variability allows the operator to determine if snapshots of well production can be representative of overall production. Some key questions to ask include the following.
 - a) Is the flow variability repeatable over time?
 - b) If so, what is the frequency and periodicity of observed flow variability (cycles)?
 - c) If the flow variability is observed as measurement spikes, are the spikes uniform in size (volume)?
 - d) Are any of the phase rate (gas, oil, water) variances correlated?
 - e) Is it just liquids that are variable?
- 2) *Perform an Extended Production Well Test.* Typically a 24-hour production well test is sufficient to observe enough data to “average” out the flow variability. However, depending on the flow dynamics, more or less time might be warranted. At least six cycles corresponding to the flow variability is generally sufficient for data analysis.

- 3) *Analyze Flow Variability Relative to Different Production Well Test Durations Through Use of Several Data Subsets of the Production Well Test.* The data from the production well test can be divided up into any number of smaller well test data sets and analyzed for an optimal production well test duration (e.g. minimum number of variable flow cycles). Statistical methods can be used.
- 4) *Establish Minimum Flow Variability Criteria for Comparison of Data Subsets.* This step can be performed prior to the data analysis, during, or after. At the operator's discretion, minimum flow variability criteria are established that allow for relative comparison of the data subsets (e.g. $\pm 5\%$ uncertainty of measurement due to flow variability for each phase rate).
- 5) *Compare Data Subsets to Minimum Flow Variability Criteria and Determine Optimal Production Well Test Start and Stop Times (Duration).* The data subsets are examined relative to the minimum flow variability criteria and the shortest production well test time that obtains accurate, representative information is determined. Additionally, the optimal duration is reviewed against production well test operational limitations and constraints that might have to be accounted for when advising on the recommended production well test duration.

C.3 Example

Consider the production well test information from an offshore well plotted in Figure C.1.

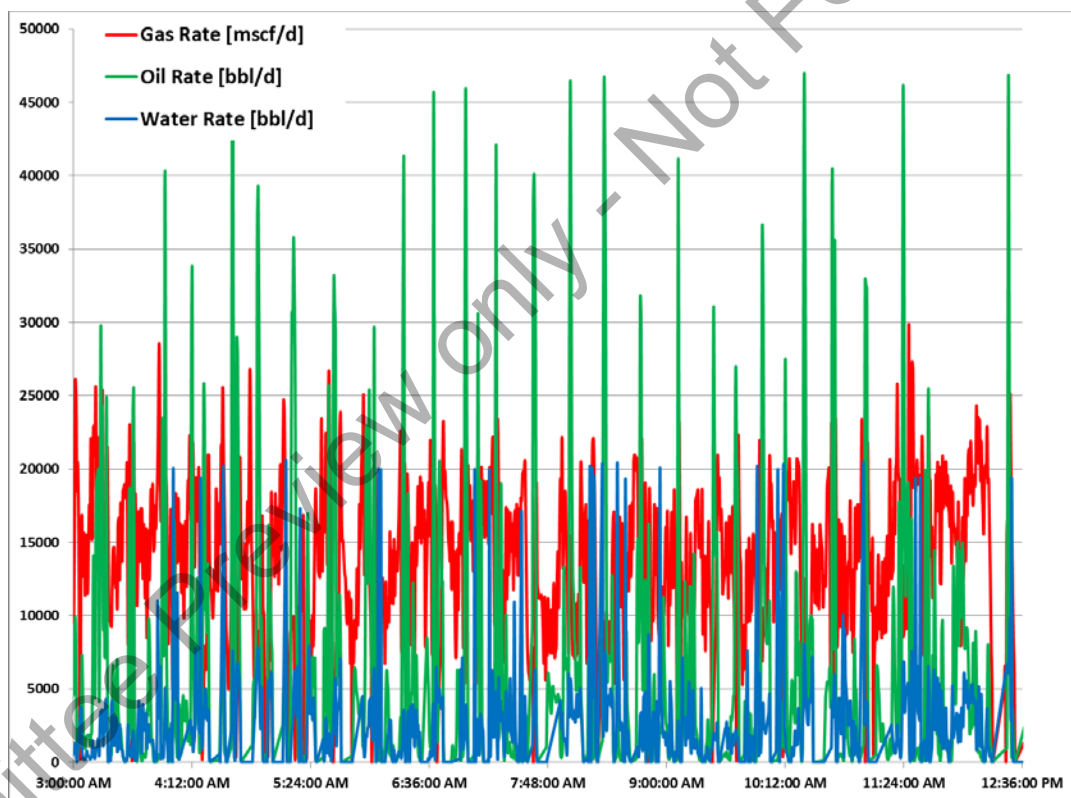


Figure C.1—Production Well Test Data Showing Flow Variability at the Measurement Points

- 1) *Characterize the Flow Variability.*

For this example, flow variability at the measurement points for gas, oil, and water are evident over a 9-hour period that data were collected for the production well test. However, it is observed that the variable flow rates demonstrate repeatability, with gas and oil rates cycling in 20-minute to 30-minute swings, with oil lagging gas. Additionally, water slugs are observed to nominally follow the oil slugs, albeit with more variability.

2) Perform an Extended Production Well Test.

In this example, a 9-hour extended production well test was deemed the maximum allowable duration for a test, due to the resultant production deferrals (other wells were shut-in for the test) and stabilization times associated with a subsea well.

3) Analyze Flow Variability Relative to Different Production Well Test Durations Through Use of Several Data Subsets of the Production Well Test.

For this example, a simple statistical analysis on different production well test lengths was evaluated to determine the optimal production well test length in the 9-hour data interval.

First, the 9-hour production well test was divided up into 841 permutations of 2-hour tests, and each test evaluated for gas, oil, and water rates (refer to Table C.1).

NOTE 1 The gas, oil, and water rates calculated in Table C.1 are not the instantaneous meter rates. The rates are calculated from the cumulative production measured during the production well test and adjusted for a daily rate.

NOTE 2 30-second data from the data historian was used, allowing for 841 different 2-hour production well tests during the 9-hour period of data. The more permutations the better, but to be statistically significant only 7 permutations are required.

Table C.1—Uncertainty Result for 2-hour Production Well Test

Permutation	Time Start	Time Stop	Test Duration (hr)	Test Gas Rate (mscf/d)	Test Oil Rate (bbl/d)	Test Water Rate (bbl/d)
1	03:00:00	05:00:00	2	14,208	6235	2290
2	03:00:30	05:00:30	2	14,230	6245	2297
3	03:01:00	05:01:00	2	14,228	6218	2294
—	—	—	—	—	—	—
—	—	—	—	—	—	—
—	—	—	—	—	—	—
840	09:59:30	11:59:30	2	14,452	5978	2807
841	10:00:00	12:00:00	2	14,463	5987	2807
				$\mu =$	13,102	5909
				$\sigma =$	542	423
				$U =$	1061	829
				$U \% =$	$\pm 8.1 \%$	$\pm 14.0 \%$
						$\pm 26.3 \%$
NOTE 1 μ = mean; σ = standard deviation; U = uncertainty = 1.96σ (95 % confidence level).						
NOTE 2 2-hour well tests at 841 different permutations.						
NOTE 3 Rates are cumulative volumes during the test, adjusted for well test length.						

Second, the mean (μ) production well test rate for each phase was calculated from the 2-hour tests, followed by the standard deviation (σ). From the standard deviation, an uncertainty (U) was calculated. The uncertainty of the flow measurement result is attributable to the variance in flow only, and not any other source. Simply stated, any 2-hour well test conducted in the 9-hour data period has a $\pm 8.1 \%$ uncertainty for gas, $\pm 14.0 \%$ uncertainty for oil, and $\pm 26.3 \%$ uncertainty for water, due entirely to the variability in the flow rates.

The statistical analysis was repeated for 601 permutations of 4-hour production well tests during the 9-hour data period, 361 permutations of 6-hour tests, and 121 permutations of 8-hour tests. The results are shown in Table C.2.

Table C.2—Combined Uncertainty Results for 2-, 4-, 6-, and 8-hour Production Well Tests

Duration	Gas Rate Uncertainty	Oil Rate Uncertainty	Water Rate Uncertainty
2	±8.1 %	±14.0 %	±26.3 %
4	±3.6 %	±8.9 %	±13.9 %
6	±3.0 %	±4.0 %	±2.9 %
8	±0.7 %	±2.2 %	±3.7 %

4) *Establish Minimum Flow Variability Criteria for Comparison of Data Subsets.*

For this example, the minimum flow variability criteria were established as ±5 % on each phase rate.

5) *Compare Data Subsets to Minimum Flow Variability Criteria and Determine Optimal Production Well Test Start and Stop Times (Duration).*

Table C.2 shows that both the 6-hour and the 8-hour production well test durations yielded individual phase rates within the uncertainty tolerance of ±5 %. Thus, either duration would be sufficient to achieve acceptable rates (relative to the flow variability observed at the measurement point) for production well testing. For this example, 6 hours was chosen such that production deferrals were minimized.

To summarize, for the well depicted in this example producing at conditions similar to the observed flow variance in Figure C.1, a 6-hour production well test is sufficient to obtain representative flow rates of gas, oil, and water with minimal impact from the flow variability.

Annex D (informative)

Example Production Well Test Report

NOTE This form is merely an example for illustration purposes only. Each company should develop its own approach. It is not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

Date: _____		EXAMPLE PRODUCTION WELL TEST REPORT		1 of 2
WELL INFORMATION				
Operator Company:		Lease:	Location:	
Contact Information:		Well Identifier:	Field / Zone:	
Operator Company Representative:		Facility:	Well Description:	
Contact Information:				
PRODUCTION WELL TEST INFORMATION				
Test Start (mm/dd/yyyy, hh:mm):		Choke Position (1/64 in):	Standard Pressure (psia):	
Test End (mm/dd/yyyy, hh:mm):		Average Wellhead Flowing Pressure (psig):	Standard Temperature (°F):	
Stabilization/Purge Duration Prior to Test (hh:mm):		Average Wellhead Flowing Temperature (°F):	Chemical Treatments:	
Test Duration (hh:mm):		Average Bottomhole Flowing Pressure (psig):		
Test System:		Average Bottomhole Flowing Temperature (°F):		
Additional Information and Data (e.g., artificial lift settings, incorporated attachments, logs, etc.):				
GAS MEASUREMENT DATA				
Meter Information	Correction Factors (applied PVT)		Sample Information	Sample Results
Tag No:	Gas Volume Correction Factor, B_g (ft ³ /scf):		Identification No.:	Gas Density (lbm/ft ³):
Type:	Solution Gas-Oil Ratio, R_s (mcf/bbl):		Date (mm/dd/yyyy):	Energy Content (Btu/scf):
	Sample ID / date (mm/dd/yyyy):		Time (hh:mm):	Gas Compressibility:
Size (in):	Volume and Rate		Method:	Composition (mol%):
Average Pressure (psig):	Uncorrected Meter Gas Volume (mcf):		Location:	
Average Temperature (°F):	Corrected Meter Gas Volume (mcf):			
Average Differential Pressure (psig):	Total Gas Volume* (mcf):			
	Total Gas Volumetric Rate (mcf/d):			
Counter Total (#):	* Corrected meter volume + evolved gas from oil - gas lift		Pressure (psig):	
			Temperature (°F):	
OIL MEASUREMENT DATA				
Meter Information	Correction Factors (applied PVT)		Sample Information	Sample Results
Tag No:	Oil Volume Correction Factor, B_o (bbl/bbl):		Identification No.:	Oil Gravity (*API @ 60 °F):
Type:	Solution Condensate-Gas Ratio, r_s (bbl/mcf):		Date (mm/dd/yyyy):	Oil Density (lbm/ft ³):
	Sample ID / date (mm/dd/yyyy):		Time (hh:mm):	Oil Viscosity (cP):
Size (in):	Volume and Rate		Method:	Water Content (%):
Average Pressure (psig):	Uncorrected Net Meter Oil Volume (bbl):		Location:	Color:
Average Temperature (°F):	Corrected Net Meter Oil Volume (bbl):			
Meter Factor:	Total Oil Volume* (bbl):			
Counter Total (#):	Total Oil Volumetric Rate (bbl/d):			
	* Corrected net meter volume + condensed oil from gas - oil power fluid		Pressure (psig):	
			Temperature (°F):	
WATER MEASUREMENT DATA				
Meter Information	Correction Factors (applied PVT)		Sample Information	Sample Results
Tag No:	Water Volume Correction Factor, B_w (bbl/bbl):		Identification No.:	Water Gravity:
Type:	Sample ID / date (mm/dd/yyyy):		Date (mm/dd/yyyy):	Oil Content (%):
Size (in):	Volume and Rate		Time (hh:mm):	Total suspended solids (mg/L):
Average Pressure (psig):	Uncorrected Meter Water Volume (bbl):		Method:	
Average Temperature (°F):	Corrected Meter Water Volume (bbl):		Location:	
Average Differential Pressure (psig):	Total Water Volume* (bbl):		Pressure (psig):	
	Total Water Volumetric Rate (bbl/d):		Temperature (°F):	
Counter Total (#):	* Corrected meter water volume + water % in oil - water power fluid			

Date: _____

EXAMPLE PRODUCTION WELL TEST REPORT

2 of 2

GAS LIFT MEASUREMENT DATA		POWER FLUID MEASUREMENT DATA	
Meter Information	Correction Factors (applied PVT)	Meter Information	Correction Factors (applied PVT)
Tag No:	Gas Volume Correction Factor For Gas Lift, B_g (ft ³ /scf):	Tag No:	Oil Volume Correction Factor For Power Fluid Oil, B_o (bbl/bbl):
Type:		Type:	
Size (in):	Sample ID / date (mm/dd/yyyy):	Size (in):	Water Volume Correction Factor For Power Fluid Water, B_w (bbl/bbl):
Average Pressure (psig):	Volume and Rate	Average Pressure (psig):	Sample ID / date (mm/dd/yyyy):
Average Temperature (°F):	Uncorrected Meter Gas Volume (mcf):	Average Temperature (°F):	Volume and Rate
Average Differential Pressure (psig):	Corrected Meter Gas Volume (mscf):	Average Differential Pressure (psig):	Uncorrected Meter Volume (bbl):
Counter Total (#):		Counter Total (#):	Corrected Meter Volume (bbl):

PRODUCTION WELL TEST RESULTS	NOTES
Total Volumetric Gas Rate at Standard Conditions* (mscf/d):	
Total Volumetric Oil Rate at Standard Conditions† (bbl/d):	
Total Volumetric Water Rate at Standard Conditions‡ (bbl/d):	
Gas-Oil Ratio (scf/bbl):	
Watercut (%):	
Shrinkage Factor, 1/ B_o (bbl/bbl):	
* Formation gas rate: Corrected meter rate + evolved gas from oil - gas lift	
† Formation oil rate: Corrected net meter rate + condensed oil from gas - oil power fluid	
‡ Formation water rate: Corrected meter water rate + water % in oil - water power fluid	

CONTROLLED OPERATIONAL CONDITIONS VALIDATION		
Parameter Acceptance Criteria	Criteria Achieved? (Y/N)	Comments
Wellhead Flowing Pressure (psig):		
Wellhead Flowing Temperature (°F):		
Bottomhole Flowing Pressure (psig):		
Bottomhole Flowing Temperature (°F):		
Gas Rate (mscf/d):		
Oil Rate (bbl/d):		
Water Rate (bbl/d):		
Gas-Oil Ratio (scf/bbl):		
Watercut (%):		
Minimum Stable Flow (hh:mm):		

PRODUCTION SIGNATURE VALIDATION		
Parameter Acceptance Criteria	Criteria Achieved? (Y/N)	Comments
Choke Position (1/64 in):		
Wellhead Flowing Pressure (psig):		
Bottomhole Flowing Pressure (psig):		
Gas Rate (mscf/d):		
Oil Rate (bbl/d):		
Water Rate (bbl/d):		
Gas-Oil Ratio (scf/bbl):		
Watercut (%):		
Gas Compositions (mol%):		
Oil Gravity (°API @ 60 °F):		
Stabilization/Purge Duration (hh:mm):		
Test Duration (hr:mm):		

Test Accepted? (Y/N):

Annex E (informative)

Field Determination of Oil Volume Correction Factor

- 1) Obtain a representative, pressurized sample of the fluid at metering conditions.
- 2) Determine the pressure and temperature of the sampled fluid when the sample was obtained, and record.
- 3) Record the initial total volume of the sample in the sample cylinder (V_i).
- 4) With the pressurized sample cylinder in an upright position, slowly bleed the sample into a clear calibrated graduated cylinder that is open to atmospheric pressure. Ensure the graduated cylinder is large enough to contain the entire sample.
- 5) Allow the sample to stabilize until no gas bubbles are visible.
- 6) Record the final total volume of the sample remaining in the graduated cylinder (V_f). Record the temperature of the sample.
- 7) If water is present in the final sample, determine the watercut using a recognized method (refer to API RP 87).
- 8) Obtain a sample of water free hydrocarbon and determine the API gravity at 60 °F or density in kg/m^3 at 15 °C.
- 9) Compute the oil volume correction factor (inverse of the shrinkage factor) using the following equation:

$$B_o = \frac{(V_i - (V_i \times X_w)) \times CTL_i}{(V_f - (V_f \times X_w)) \times CTL_f}$$

where

- | | |
|---------|--|
| B_o | is oil volume correction factor for oil accounting for phase change of produced oil from meter to standard conditions (bbl/bbl, m^3/m^3); |
| V_i | is total volume of initial sample in the sample cylinder; |
| V_f | is total volume of final sample in the graduated cylinder; |
| X_w | is volume fraction of water in the final sample; |
| CTL_i | is temperature correction factor based on temperature during sampling (refer to API MPMS Ch. 11.1 for procedure); |
| CTL_f | is temperature correction factor based on temperature of final sample (refer to API MPMS Ch. 11.1 for procedure). |

Annex F (informative)

Calculation of Water Volume Correction Factor

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

$$B_w = \frac{\rho_{w,sc}}{\rho_{w,mc}}$$

where

- B_w is water volume correction factor for water from meter to standard conditions (bbl/bbl, m³/m³);
- $\rho_{w,sc}$ is density of produced water at standard conditions (lbm/scf, kg/m³);
- $\rho_{w,mc}$ is density of produced water meter conditions (lbm/ft³, kg/m³).

If the information required in the equation above is not available, then the following curve fit equation can be used.

For customary units and standard temperature of 60 °F:

$$B_w = 1 / \left[1 - (1.0312 \times 10^{-4} + 7.1568 \times 10^{-6} \times B) \times \Delta T - (1.2701 \times 10^{-6} - 4.4641 \times 10^{-8} \times B) \times (\Delta T)^2 + (1.2333 \times 10^{-9} - 2.2436 \times 10^{-11} \times B) \times (\Delta T)^3 \right]$$

where

- B is % salinity by weight. If ρ_{60} is known, B can also be calculated using the formula:

$$B = (\rho_{60} - 999.0) / 7.2;$$
- ΔT is $T - 60$;
- T is water temperature in °F.

This correction is valid for produced water with salinity up to 14 % by weight and temperatures from 60 °F to 280 °F (7.2 kg/m³ = 1 % salinity).

For SI units and standard temperature of 15 °C:

$$B_w = 1 / \left[1 - (1.8562 \times 10^{-4} + 1.2882 \times 10^{-5} \times B) \times \Delta T - (4.1151 \times 10^{-6} - 1.4464 \times 10^{-7} \times B) \times (\Delta T)^2 + (7.1926 \times 10^{-9} - 1.3085 \times 10^{-10} \times B) \times (\Delta T)^3 \right]$$

where

- B is % salinity by weight. If ρ_{15} is known, B can also be calculated using the formula:

$$B = (\rho_{15} - 999.0) / 7.2;$$
- ΔT is $T - 15$;
- T is water temperature in °C.

This correction is valid for produced water with salinity up to 14 % by weight and temperatures from 15 °C to 138 °C (7.2 kg/m³ = 1 % salinity).

Annex G (informative)

Example Calculations of Production Well Test Rates

NOTE The following is merely an example for illustration purposes only. It is not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

G.1 Separator Measurement System

G.1.1 General

This example shows a calculation of total gas, oil, and water production volume and rate for the duration of a production well test associated with a three-phase separator measurement system (refer to the calculation procedure detailed in 6.3). In this example, an oil well with gas lift is evaluated.

G.1.2 Customary Units

G.1.2.1 Measured Quantities

- Gas volume of the separator gas outlet flow meter, at meter conditions ($GV_{\text{sep-g,mc}}$): 40 mcf.
- Oil volume of the separator oil outlet flow meter, at meter conditions ($OV_{\text{sep-o,mc}}$): 400 bbl.
- Water volume of the separator water outlet flow meter, at meter conditions ($WV_{\text{sep-w,mc}}$): 150 bbl.
- Gas volume of the gas lift gas flow meter, at meter conditions ($GV_{\text{gl,mc}}$): 6 mcf.
- Volume fraction of water in the oil/water mixture at standard conditions, obtained from sample analysis ($X_{\text{w,sc}}$): 0.01.
- Duration of production well test (Δt): 6 hours.

G.1.2.2 Known Parameters

- Gas volume correction factor for separator gas accounting for phase change of produced gas from meter to standard conditions ($B_{\text{g,sep}}$): 0.06468 ft³/scf.
- Oil volume correction factor for separator oil accounting for phase change of produced oil from meter to standard conditions ($B_{\text{o,sep}}$): 1.042 bbl/bbl.
- Water volume correction factor for separator water from meter to standard conditions ($B_{\text{w,sep}}$): 1.005 bbl/bbl.
- Solution GOR of evolved gas (from separator to standard conditions) at standard conditions, per oil volume at standard conditions ($R_{\text{s,sep}}$): 0.06965 mscf/bbl.
- Solution CGR of condensed gas (from separator to standard conditions) at standard conditions, per gas volume at standard conditions ($r_{\text{s,sep}}$): 0.0 bbl/mscf.
- Gas volume correction factor for gas lift gas accounting for phase change of gas lift gas from meter to standard conditions ($B_{\text{g,gl}}$): 0.01261 ft³/scf.
- Pressure of 14.696 psia at standard conditions.

- Temperature of 60 °F at standard conditions.
- Separator pressure at 232 psig.
- Separator temperature at 92 °F.

G.1.2.3 Calculation

The volume fraction of water in the oil/water mixture at the separator oil outlet adjusted to meter conditions ($X_{w,mc}$) is calculated from Equation (16):

$$X_{w,mc} = \frac{0.01 \times 1.005 \text{ bbl/bbl}}{0.01 \times 1.005 \text{ bbl/bbl} + (1 - 0.01) \times 1.042 \text{ bbl/bbl}} = 0.009652$$

The oil volume attributed to oil measured at the separator oil outlet at standard conditions ($OV_{sep-o,sc}$) is calculated from Equation (8):

$$OV_{sep-o,sc} = 400 \text{ bbl} \times (1 - 0.009652) \times \frac{1}{1.042 \text{ bbl/bbl}} = 380.3 \text{ bbl}$$

The oil volume attributed to oil condensed from gas measured at the separator gas outlet at standard conditions ($OV_{sep-g,sc}$) is calculated from Equation (9):

$$OV_{sep-g,sc} = 40 \text{ mcf} \times \frac{1}{0.06468 \text{ ft}^3/\text{scf}} \times 0 \frac{\text{bbl}}{\text{mscf}} = 0 \text{ bbl}$$

The oil volume total for the production well test at standard conditions ($OV_{tot,sc}$) is calculated from Equation (6) with oil volume of artificial lift power fluid oil at standard conditions ($OV_{pf,sc}$) equal to zero:

$$OV_{tot,sc} = 380.3 \text{ bbl} + 0 \text{ bbl} - 0 \text{ bbl} = 380.3 \text{ bbl}$$

The oil volumetric rate total for the production well test at standard conditions ($OVR_{tot,sc}$) is calculated from Equation (7):

$$OVR_{tot,sc} = \frac{380.3 \text{ bbl}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 1521 \text{ bbl/d}$$

The gas volume of artificial lift gas lift gas at standard conditions ($GV_{gl,sc}$) is calculated from Equation (5):

$$GV_{gl,sc} = 6 \text{ mcf} \times \frac{1}{0.01261 \text{ ft}^3/\text{scf}} = 476 \text{ mscf}$$

The gas volume attributed to gas measured at the separator gas outlet at standard conditions ($GV_{sep-g,sc}$) is calculated from Equation (3):

$$GV_{sep-g,sc} = 40 \text{ mcf} \times \frac{1}{0.06468 \text{ ft}^3/\text{scf}} = 618.4 \text{ mscf}$$

The gas volume attributed to gas evolved from oil measured at the separator oil outlet at standard conditions ($GV_{sep-o,sc}$) is calculated from Equation (4):

$$GV_{sep-o,sc} = 400 \text{ bbl} \times (1 - 0.009652) \times \frac{1}{1.042 \text{ bbl/bbl}} \times 0.06965 \text{ mscf/bbl} = 26.49 \text{ mscf}$$

The gas volume total for the production well test at standard conditions ($GV_{\text{tot,sc}}$) is calculated from Equation (1):

$$GV_{\text{tot,sc}} = 618.4 \text{ mscf} + 26.49 \text{ mscf} - 476 \text{ mscf} = 168.9 \text{ mscf}$$

The gas volumetric rate total for the production well test at standard conditions ($GVR_{\text{tot,sc}}$) is calculated from Equation (2):

$$GVR_{\text{tot,sc}} = \frac{168.9 \text{ mscf}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 675.5 \text{ mscf/d}$$

The water volume measured at the separator oil outlet at standard conditions ($WV_{\text{sep-o,sc}}$) is calculated from Equation (14):

$$WV_{\text{sep-o,sc}} = 400 \text{ bbl} \times 0.009652 \times \frac{1}{1.005 \text{ bbl/bbl}} = 3.841 \text{ bbl}$$

The water volume measured at the separator water outlet at standard conditions ($WV_{\text{sep-w,sc}}$) is calculated from Equation (13):

$$WV_{\text{sep-w,sc}} = 150 \text{ bbl} \times \frac{1}{1.005 \text{ bbl/bbl}} = 149.3 \text{ bbl}$$

The water volume total for the production well test at standard conditions ($WV_{\text{tot,sc}}$) is calculated from Equation (11) with water volume of artificial lift power fluid water at standard conditions ($WV_{\text{pf,sc}}$) equal to zero:

$$WV_{\text{tot,sc}} = 149.3 \text{ bbl} + 3.841 \text{ bbl} + 0 \text{ bbl} = 153.1 \text{ bbl}$$

The water volumetric rate total for the production well test at standard conditions ($WVR_{\text{tot,sc}}$) is calculated from Equation (12):

$$WVR_{\text{tot,sc}} = \frac{153.1 \text{ bbl}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 612.4 \text{ bbl/d}$$

The GOR for the production well test at standard conditions (GOR) is calculated from Equation (17):

$$GOR = \frac{168.9 \text{ mscf}}{380.3 \text{ bbl}} \times 1000 = 444 \text{ scf/bbl}$$

The watercut for the production well test at standard conditions (WC_{sc}) is calculated from Equation (18):

$$WC_{\text{sc}} = \frac{153.1 \text{ bbl}}{153.1 \text{ bbl} + 380.3 \text{ bbl}} \times 100 \% = 28.7 \%$$

G.1.3 SI Units

G.1.3.1 Measured Quantities

- Gas volume of the separator gas outlet flow meter, at meter conditions ($GV_{\text{sep-g,mc}}$): $1.133 \times 10^3 \text{ m}^3$.
- Oil volume of the separator oil outlet flow meter, at meter conditions ($OV_{\text{sep-o,mc}}$): 63.59 m^3 .
- Water volume of the separator water outlet flow meter, at meter conditions ($WV_{\text{sep-w,mc}}$): 23.85 m^3 .

- Gas volume of the gas lift gas flow meter, at meter conditions ($GV_{gl,mc}$): $0.1699 \times 10^3 \text{ m}^3$.
- Volume fraction of water in the oil/water mixture at standard conditions, obtained from sample analysis ($X_{w,sc}$): 0.01.
- Duration of production well test (Δt): 6 hours.

G.1.3.2 Known Parameters

- Gas volume correction factor for separator gas accounting for phase change of produced gas from meter to standard conditions ($B_{g,sep}$): $0.06468 \text{ m}^3/\text{m}^3$.
- Oil volume correction factor for separator oil accounting for phase change of produced oil from meter to standard conditions ($B_{o,sep}$): $1.042 \text{ m}^3/\text{m}^3$.
- Water volume correction factor for separator water from meter to standard conditions ($B_{w,sep}$): $1.005 \text{ m}^3/\text{m}^3$.
- Solution GOR of evolved gas (from separator to standard conditions) at standard conditions, per oil volume at standard conditions ($R_{s,sep}$): $0.01234 \times 10^3 \text{ m}^3/\text{m}^3$.
- Solution CGR of condensed gas (from separator to standard conditions) at standard conditions, per gas volume at standard conditions ($r_{s,sep}$): $0.0 \text{ m}^3/10^3 \text{ m}^3$.
- Gas volume correction factor for gas lift gas accounting for phase change of gas lift gas from meter to standard conditions ($B_{g,gl}$): $0.01261 \text{ m}^3/\text{m}^3$.
- Pressure of 1.013 bara at standard conditions.
- Temperature of 15 °C at standard conditions.
- Separator pressure at 16 barg.
- Separator temperature at 33 °C.

G.1.3.3 Calculation

The volume fraction of water in the oil/water mixture adjusted to meter conditions ($X_{w,mc}$) is calculated from Equation (16):

$$X_{w,mc} = \frac{0.01 \times 1.005 \text{ m}^3/\text{m}^3}{0.01 \times 1.005 \text{ m}^3/\text{m}^3 + (1 - 0.01) \times 1.042 \text{ m}^3/\text{m}^3} = 0.009652$$

The oil volume attributed to oil measured at the separator oil outlet at standard conditions ($OV_{sep-o,sc}$) is calculated from Equation (8):

$$OV_{sep-o,sc} = 63.59 \text{ m}^3 \times (1 - 0.009652) \times \frac{1}{1.042 \text{ m}^3/\text{m}^3} = 60.46 \text{ m}^3$$

The oil volume attributed to oil condensed from gas measured at the separator gas outlet at standard conditions ($OV_{sep-g,sc}$) is calculated from Equation (9):

$$OV_{sep-g,sc} = 1.133 \times 10^3 \text{ m}^3 \times \frac{1}{0.06468 \text{ m}^3/\text{m}^3} \times 0 \frac{\text{m}^3}{10^3 \text{ m}^3} = 0 \text{ m}^3$$

The oil volume total for the production well test at standard conditions ($OV_{\text{tot,sc}}$) is calculated from Equation (6) with oil volume of artificial lift power fluid oil at standard conditions ($OV_{\text{pf,sc}}$) equal to zero:

$$OV_{\text{tot,sc}} = 60.46 \text{ m}^3 + 0 \text{ m}^3 - 0 \text{ m}^3 = 60.46 \text{ m}^3$$

The oil volumetric rate total for the production well test at standard conditions ($OVR_{\text{tot,sc}}$) is calculated from Equation (7):

$$OVR_{\text{tot,sc}} = \frac{60.46 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 241.8 \text{ m}^3/\text{d}$$

The gas volume of artificial lift gas lift gas at standard conditions ($GV_{\text{gl,sc}}$) is calculated from Equation (5):

$$GV_{\text{gl,sc}} = 0.1699 \text{ } 10^3 \text{ m}^3 \times \frac{1}{0.01261 \text{ m}^3/\text{m}^3} = 13.48 \text{ } 10^3 \text{ m}^3$$

The gas volume attributed to gas measured at the separator gas outlet at standard conditions ($GV_{\text{sep-g,sc}}$) is calculated from Equation (3):

$$GV_{\text{sep-g,sc}} = 1.133 \text{ } 10^3 \text{ m}^3 \times \frac{1}{0.06468 \text{ m}^3/\text{m}^3} = 17.52 \text{ } 10^3 \text{ m}^3$$

The gas volume attributed to gas evolved from oil measured at the separator oil outlet at standard conditions ($GV_{\text{sep-o,sc}}$) is calculated from Equation (4):

$$GV_{\text{sep-o,sc}} = 63.59 \text{ m}^3 \times (1 - 0.009652) \times \frac{1}{1.042 \text{ m}^3/\text{m}^3} \times 0.01234 \text{ } 10^3 \text{ m}^3/\text{m}^3 = 0.7461 \text{ } 10^3 \text{ m}^3$$

The gas volume total for the production well test at standard conditions ($GV_{\text{tot,sc}}$) is calculated from Equation (1):

$$GV_{\text{tot,sc}} = 17.52 \text{ } 10^3 \text{ m}^3 + 0.7461 \text{ } 10^3 \text{ m}^3 - 13.48 \text{ } 10^3 \text{ m}^3 = 4.784 \text{ } 10^3 \text{ m}^3$$

The gas volumetric rate total for the production well test at standard conditions ($GVR_{\text{tot,sc}}$) is calculated from Equation (2):

$$GVR_{\text{tot,sc}} = \frac{4.784 \text{ } 10^3 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 19.13 \text{ } 10^3 \text{ m}^3/\text{d}$$

The water volume measured at the separator oil outlet at standard conditions ($WV_{\text{sep-o,sc}}$) is calculated from Equation (14):

$$WV_{\text{sep-o,sc}} = 63.59 \text{ m}^3 \times 0.009652 \times \frac{1}{1.005 \text{ m}^3/\text{m}^3} = 0.6107 \text{ m}^3$$

The water volume measured at the separator water outlet at standard conditions ($WV_{\text{sep-w,sc}}$) is calculated from Equation (13):

$$WV_{\text{sep-w,sc}} = 23.85 \text{ m}^3 \times \frac{1}{1.005 \text{ m}^3/\text{m}^3} = 23.73 \text{ m}^3$$

The water volume total for the production well test at standard conditions ($WV_{\text{tot,sc}}$) is calculated from Equation (11) with water volume of artificial lift power fluid water at standard conditions ($WV_{\text{pf,sc}}$) equal to zero:

$$WV_{\text{tot,sc}} = 23.73 \text{ m}^3 + 0.6107 \text{ m}^3 + 0 \text{ m}^3 = 24.34 \text{ m}^3$$

The water volumetric rate total for the production well test at standard conditions ($WVR_{\text{tot,sc}}$) is calculated from Equation (12):

$$WVR_{\text{tot,sc}} = \frac{24.34 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 97.37 \text{ m}^3/\text{d}$$

The GOR for the production well test at standard conditions is calculated from Equation (17):

$$\text{GOR} = \frac{4.784 \times 10^3 \text{ m}^3}{60.46 \text{ m}^3} \times 1000 = 79.12 \text{ m}^3/\text{m}^3$$

The watercut for the production well test at standard conditions (WC_{sc}) is calculated from Equation (18):

$$WC_{\text{sc}} = \frac{24.34 \text{ m}^3}{24.34 \text{ m}^3 + 60.46 \text{ m}^3} \times 100 \% = 28.7 \%$$

G.2 Multiphase Measurement System

G.2.1 General

This example shows a calculation of total gas, oil, and water production volume and rate for the duration of a production well test associated with a multiphase measurement system (refer to the calculation procedure detailed in 6.4). In this example, a wet gas well is evaluated.

G.2.2 Customary Units

G.2.2.1 Measured Quantities

- Gas volume of the multiphase flow meter, at meter conditions ($GV_{\text{mpfm-g,mc}}$): 500 mcf.
- Oil volume of the multiphase flow meter, at meter conditions ($OV_{\text{mpfm-o,mc}}$): 600 bbl.
- Water volume of the multiphase flow meter, at meter conditions ($WV_{\text{mpfm-w,mc}}$): 30 bbl.
- Duration of production well test (Δt): 6 hours.

G.2.2.2 Known Parameters

- Gas volume correction factor for multiphase flow meter gas accounting for phase change of produced gas from meter to standard conditions ($B_{\text{g,mpfm}}$): 0.0110 ft³/scf.
- Oil volume correction factor for multiphase flow meter oil accounting for phase change of produced oil from meter to standard conditions ($B_{\text{o,mpfm}}$): 1.289 bbl/bbl.
- Water volume correction factor for multiphase flow meter water from meter to standard conditions ($B_{\text{w,mpfm}}$): 1.032 bbl/bbl.
- Solution GOR of evolved gas (from meter to standard conditions) at standard conditions, per oil volume at standard conditions ($R_{\text{s,mpfm}}$): 0.4488 mscf/bbl.

- Solution CGR of condensed gas (from meter to standard conditions) at standard conditions, per gas volume at standard conditions ($r_{s,mpfm}$): 0.0021 bbl/mscf.
- Pressure of 14.696 psia at standard conditions.
- Temperature of 60 °F at standard conditions.
- Multiphase flow meter pressure at 1523 psig.
- Multiphase flow meter temperature at 198 °F.

G.2.2.3 Calculation

The gas volume attributed to gas measured at the multiphase flow meter at standard conditions ($GV_{mpfm-g,sc}$) is calculated from Equation (21):

$$GV_{mpfm-g,sc} = 500 \text{ mcf} \times \frac{1}{0.0110 \text{ ft}^3/\text{scf}} = 45,517 \text{ mscf}$$

The gas volume attributed to gas evolved from oil measured at the multiphase flow meter at standard conditions ($GV_{mpfm-o,sc}$) is calculated from Equation (22):

$$GV_{mpfm-o,sc} = 600 \text{ bbl} \times \frac{1}{1.289 \text{ bbl/bbl}} \times 0.4488 \text{ mscf/bbl} = 209.0 \text{ mscf}$$

The gas volume total for the production well test at standard conditions ($GV_{tot,sc}$) is calculated from Equation (19) with gas volume of artificial lift gas lift gas at standard conditions ($GV_{gl,sc}$) equal to zero:

$$GV_{tot,sc} = 45,517 \text{ mscf} + 209.0 \text{ mscf} - 0 \text{ mscf} = 45,726 \text{ mscf}$$

The gas volumetric rate total for the production well test at standard conditions ($GVR_{tot,sc}$) is calculated from Equation (20):

$$GVR_{tot,sc} = \frac{45,726 \text{ mscf}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 182,904 \text{ mscf/d}$$

The oil volume attributed to oil measured at the multiphase flow meter at standard conditions ($OV_{mpfm-o,sc}$) is calculated from Equation (25):

$$OV_{mpfm-o,sc} = 600 \text{ bbl} \times \frac{1}{1.289 \text{ bbl/bbl}} = 465.7 \text{ bbl}$$

The oil volume attributed to oil condensed from gas measured at the multiphase flow meter at standard conditions ($OV_{mpfm-g,sc}$) is calculated from Equation (26):

$$OV_{mpfm-g,sc} = 500 \text{ mcf} \times \frac{1}{0.0110 \text{ ft}^3/\text{scf}} \times 0.0021 \text{ bbl/mscf} = 97.33 \text{ bbl}$$

The oil volume total for the production well test at standard conditions ($OV_{tot,sc}$) is calculated from Equation (23) with oil volume of artificial lift power fluid oil at standard conditions ($OV_{pf,sc}$) equal to zero:

$$OV_{tot,sc} = 465.7 \text{ bbl} + 97.33 \text{ bbl} - 0 \text{ bbl} = 563.0 \text{ bbl}$$

The oil volumetric rate total for the production well test at standard conditions ($OVR_{tot,sc}$) is calculated from Equation (24):

$$OVR_{tot,sc} = \frac{563.0 \text{ bbl}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 2251 \text{ bbl/d}$$

The water volume measured at the multiphase flow meter at standard conditions ($WV_{mpfm-w,sc}$) is calculated from Equation (29):

$$WV_{mpfm-w,sc} = 30 \text{ bbl} \times \frac{1}{1.032 \text{ bbl/bbl}} = 29.07 \text{ bbl}$$

The water volume total for the production well test at standard conditions ($WV_{tot,sc}$) is calculated from Equation (27) with water volume of artificial lift power fluid water at standard conditions ($WV_{pf,sc}$) equal to zero:

$$WV_{tot,sc} = 29.07 \text{ bbl} + 0 \text{ bbl} - 0 \text{ bbl} = 29.07 \text{ bbl}$$

The water volumetric rate total for the production well test at standard conditions ($WVR_{tot,sc}$) is calculated from Equation (28):

$$WVR_{tot,sc} = \frac{29.07 \text{ bbl}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 116.3 \text{ bbl/d}$$

The GOR for the production well test at standard conditions is calculated from Equation (17):

$$GOR = \frac{45,726 \text{ mscf}}{563 \text{ bbl}} \times 1000 = 81,222 \text{ scf/bbl}$$

The watercut for the production well test at standard conditions (WC_{sc}) is calculated from Equation (18):

$$WC_{sc} = \frac{29.07 \text{ bbl}}{29.07 \text{ bbl} + 563 \text{ bbl}} \times 100 \% = 4.9 \%$$

G.2.3 SI Units

G.2.3.1 Measured Quantities

- Gas volume of the multiphase flow meter, at meter conditions ($GV_{mpfm-g,mc}$): $14.16 \times 10^3 \text{ m}^3$.
- Oil volume of the multiphase flow meter, at meter conditions ($OV_{mpfm-o,mc}$): 95.40 m^3 .
- Water volume of the multiphase flow meter, at meter conditions ($WV_{mpfm-w,mc}$): 4.770 m^3 .
- Duration of production well test (Δt): 6 hours.

G.2.3.2 Known Parameters

- Gas volume correction factor for multiphase flow meter gas accounting for phase change of produced gas from meter to standard conditions ($B_{g,mpfm}$): $0.0110 \text{ m}^3/\text{m}^3$.
- Oil volume correction factor for multiphase flow meter oil accounting for phase change of produced oil from meter to standard conditions ($B_{o,mpfm}$): $1.289 \text{ m}^3/\text{m}^3$.

- Water volume correction factor for multiphase flow meter water from meter to standard conditions ($B_{w,mpfm}$): $1.032 \text{ m}^3/\text{m}^3$.
- Solution GOR of evolved gas (from meter to standard conditions) at standard conditions, per oil volume at standard conditions ($R_{s,mpfm}$): $0.07950 \text{ m}^3/\text{m}^3$.
- Solution CGR of condensed gas (from meter to standard conditions) at standard conditions, per gas volume at standard conditions ($r_{s,mpfm}$): $0.01210 \text{ m}^3/10^3 \text{ m}^3$.
- Pressure of 1.013 bara at standard conditions.
- Temperature of 15°C at standard conditions.
- Multiphase flow meter pressure at 105 barg.
- Multiphase flow meter temperature at 92°C .

G.2.3.3 Calculation

The gas volume attributed to gas measured at the multiphase flow meter at standard conditions ($GV_{mpfm-g,sc}$) is calculated from Equation (21):

$$GV_{mpfm-g,sc} = 14.16 \text{ } 10^3 \text{ m}^3 \times \frac{1}{0.0110 \text{ m}^3/\text{m}^3} = 1289 \text{ } 10^3 \text{ m}^3$$

The gas volume attributed to gas evolved from oil measured at the multiphase flow meter at standard conditions ($GV_{mpfm-o,sc}$) is calculated from Equation (22):

$$GV_{mpfm-o,sc} = 95.40 \text{ m}^3 \times \frac{1}{1.289 \text{ m}^3/\text{m}^3} \times 0.07950 \text{ m}^3/\text{m}^3 = 5.887 \text{ } 10^3 \text{ m}^3$$

The gas volume total for the production well test at standard conditions ($GV_{tot,sc}$) is calculated from Equation (19) with gas volume of artificial lift gas lift gas at standard conditions ($GV_{gl,sc}$) equal to zero:

$$GV_{tot,sc} = 1289 \text{ } 10^3 \text{ m}^3 + 5.887 \text{ } 10^3 \text{ m}^3 - 0 \text{ } 10^3 \text{ m}^3 = 1295 \text{ } 10^3 \text{ m}^3$$

The gas volumetric rate total for the production well test at standard conditions ($GVR_{tot,sc}$) is calculated from Equation (20):

$$GVR_{tot,sc} = \frac{1295 \text{ } 10^3 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 5179 \text{ } 10^3 \text{ m}^3/\text{d}$$

The oil volume attributed to oil measured at the multiphase flow meter at standard conditions ($OV_{mpfm-o,sc}$) is calculated from Equation (25):

$$OV_{mpfm-o,sc} = 95.40 \text{ m}^3 \times \frac{1}{1.289 \text{ m}^3/\text{m}^3} = 74.03 \text{ m}^3$$

The oil volume attributed to oil condensed from gas measured at the multiphase flow meter at standard conditions ($OV_{mpfm-g,sc}$) is calculated from Equation (26):

$$OV_{mpfm-g,sc} = 14.16 \text{ } 10^3 \text{ m}^3 \times \frac{1}{0.0110 \text{ m}^3/\text{m}^3} \times 0.0121 \text{ m}^3 / 10^3 \text{ m}^3 = 15.55 \text{ m}^3$$

The oil volume total for the production well test at standard conditions ($OV_{\text{tot,sc}}$) is calculated from Equation (23) with oil volume of artificial lift power fluid oil at standard conditions ($OV_{\text{pf,sc}}$) equal to zero:

$$OV_{\text{tot,sc}} = 74.03 \text{ m}^3 + 15.55 \text{ m}^3 - 0 \text{ m}^3 = 89.58 \text{ m}^3$$

The oil volumetric rate total for the production well test at standard conditions ($OVR_{\text{tot,sc}}$) is calculated from Equation (24):

$$OVR_{\text{tot,sc}} = \frac{89.58 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 358.3 \text{ m}^3/\text{d}$$

The water volume measured at the multiphase flow meter at standard conditions ($WV_{\text{mpfm-w,sc}}$) is calculated from Equation (29):

$$WV_{\text{mpfm-w,sc}} = 4.770 \text{ m}^3 \times \frac{1}{1.032 \text{ m}^3/\text{m}^3} = 4.622 \text{ m}^3$$

The water volume total for the production well test at standard conditions ($WV_{\text{tot,sc}}$) is calculated from Equation (27) with water volume of artificial lift power fluid water at standard conditions ($WV_{\text{pf,sc}}$) equal to zero:

$$WV_{\text{tot,sc}} = 4.622 \text{ m}^3 + 0 \text{ m}^3 - 0 \text{ m}^3 = 4.622 \text{ m}^3$$

The water volumetric rate total for the production well test at standard conditions ($WVR_{\text{tot,sc}}$) is calculated from Equation (28):

$$WVR_{\text{tot,sc}} = \frac{4.622 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 18.49 \text{ m}^3/\text{d}$$

The GOR for the production well test at standard conditions is calculated from Equation (17):

$$\text{GOR} = \frac{1,295 \text{ m}^3}{89.58 \text{ m}^3} \times 1000 = 14,453 \text{ m}^3/\text{m}^3$$

The watercut for the production well test at standard conditions (WC_{sc}) is calculated from Equation (18):

$$WC_{\text{sc}} = \frac{4.622 \text{ m}^3}{4.622 \text{ m}^3 + 89.58 \text{ m}^3} \times 100 \% = 4.9 \%$$

G.3 Tank Measurement System

G.3.1 General

This example shows a calculation of total gas, oil, and water production volume and rate for the duration of a production well test associated with a tank measurement system (refer to the calculation procedure detailed in 6.5). In this example, an oil well with jet pump artificial lift (water) is evaluated.

NOTE In this example, oil is metered at the oil tank outlet, and water is metered at the water tank outlet. Gas volume evolved from oil tank oil is estimated and not metered.

G.3.2 Customary Units

G.3.2.1 Measured Quantities

— Gas volume of the process gas outlet flow meter, at meter conditions ($GV_{\text{proc-g,mc}}$): 3.000 mcf.

- Oil volume of the oil tank outlet flow meter, at meter conditions ($OV_{\text{tank-o,mc}}$): 75.00 bbl.
- Water volume of the water tank outlet flow meter, at meter conditions ($WV_{\text{tank-w,mc}}$): 315.0 bbl.
- Water volume of the artificial lift power fluid (water) flow meter, at meter conditions ($WV_{\text{pf,mc}}$): 300.0 bbl.
- Volume fraction of water in the oil/water mixture at standard conditions, obtained from sample analysis ($X_{\text{w,sc}}$): 0.01.
- Duration of production well test (Δt): 6 hours.

G.3.2.2 Known Parameters

- Gas volume correction factor for process gas accounting for phase change of produced gas from meter to standard conditions ($B_{\text{g,proc}}$): 0.06470 ft³/scf.
- Oil volume correction factor for oil tank oil accounting for phase change of produced oil from meter to standard conditions ($B_{\text{o,tank-o}}$): 1.004 bbl/bbl.
- Water volume correction factor for oil tank water from meter to standard conditions ($B_{\text{w,tank-o}}$): 1.001 bbl/bbl.
- Water volume correction factor for water tank water from meter to standard conditions ($B_{\text{w,tank-w}}$): 1.001 bbl/bbl.
- Solution GOR of evolved gas (from separator to standard conditions) at standard conditions, per oil volume at standard conditions ($R_{\text{s,tank-o}}$): 0.0001 mscf/bbl.
- Solution CGR of condensed gas (from process to standard conditions) at standard conditions, per gas volume at standard conditions ($r_{\text{s,proc}}$): 0.0000 bbl/mscf.
- Water volume correction factor for artificial lift power fluid water from meter to standard conditions ($B_{\text{w,pf}}$): 1.002 bbl/bbl.
- Pressure of 14.696 psia at standard conditions.
- Temperature of 60 °F at standard conditions.
- Oil tank pressure at 16 psig.
- Oil tank temperature at 78.8 °F.
- Process pressure (gas meter) at 232 psig.
- Process temperature (gas meter) at 91.8 °F.
- Water tank pressure at 14.7 psig.
- Water tank temperature at 78.8 °F.

G.3.2.3 Calculation

The volume fraction of water in the oil/water mixture at the oil tank outlet adjusted to meter conditions ($X_{\text{w,mc}}$) is calculated from Equation (16), substituting $B_{\text{w,tank-o}}$ (water volume correction factor for oil tank water from meter to standard conditions) for $B_{\text{w,sep}}$ and $B_{\text{o,tank-o}}$ (oil volume correction factor for oil tank oil accounting for phase change of produced oil from meter to standard conditions) for $B_{\text{o,sep}}$:

$$X_{\text{w,mc}} = \frac{0.01 \times 1.001 \text{ bbl/bbl}}{0.01 \times 1.001 \text{ bbl/bbl} + (1 - 0.01) \times 1.004 \text{ bbl/bbl}} = 0.0100$$

The oil volume attributed to oil measured at the oil tank outlet at standard conditions ($OV_{\text{tank-o,sc}}$) is calculated from Equation (37):

$$OV_{\text{tank-o,sc}} = 75.00 \text{ bbl} \times (1 - 0.0100) \times \frac{1}{1.004 \text{ bbl/bbl}} = 73.96 \text{ bbl}$$

The oil volume attributed to oil condensed from gas measured at the process gas outlet at standard conditions ($OV_{\text{proc-g,sc}}$) is calculated from Equation (39):

$$OV_{\text{proc-g,sc}} = 3.000 \text{ mcf} \times \frac{1}{0.06470 \text{ ft}^3/\text{scf}} \times 0 \frac{\text{bbl}}{\text{mscf}} = 0 \text{ bbl}$$

The oil volume total for the production well test at standard conditions ($OV_{\text{tot,sc}}$) is calculated from Equation (35) with oil volume of artificial lift power fluid oil at standard conditions ($OV_{\text{pf,sc}}$) equal to zero:

$$OV_{\text{tot,sc}} = 73.96 \text{ bbl} + 0 \text{ bbl} - 0 \text{ bbl} = 73.96 \text{ bbl}$$

The oil volumetric rate total for the production well test at standard conditions ($OVR_{\text{tot,sc}}$) is calculated from Equation (36):

$$OVR_{\text{tot,sc}} = \frac{73.96 \text{ bbl}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 295.8 \text{ bbl/d}$$

The gas volume attributed to gas measured at the process gas outlet at standard conditions ($GV_{\text{proc-g,sc}}$) is calculated from Equation (32):

$$GV_{\text{proc-g,sc}} = 3.000 \text{ mcf} \times \frac{1}{0.06470 \text{ ft}^3/\text{scf}} = 46.38 \text{ mscf}$$

The gas volume attributed to gas evolved from the oil tank at standard conditions ($GV_{\text{tank-o,sc}}$) is calculated from Equation (34):

$$GV_{\text{tank-o,sc}} = 73.96 \text{ bbl} \times 0.0001 \text{ mscf/bbl} = 0.0095 \text{ mscf}$$

The gas volume total for the production well test at standard conditions ($GV_{\text{tot,sc}}$) is calculated from Equation (30) with gas volume of artificial lift gas lift gas at standard conditions ($GV_{\text{gl,sc}}$) equal to zero:

$$GV_{\text{tot,sc}} = 46.38 \text{ mscf} + 0.0095 \text{ mscf} - 0 \text{ mscf} = 46.39 \text{ mscf}$$

The gas volumetric rate total for the production well test at standard conditions ($GVR_{\text{tot,sc}}$) is calculated from Equation (31):

$$GVR_{\text{tot,sc}} = \frac{46.39 \text{ mscf}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 185.6 \text{ mscf/d}$$

The water volume measured at the oil tank outlet at standard conditions ($WV_{\text{tank-o,sc}}$) is calculated from Equation (44):

$$WV_{\text{tank-o,sc}} = 75.00 \text{ bbl} \times 0.0100 \times \frac{1}{1.001 \text{ bbl/bbl}} = 0.7470 \text{ bbl}$$

The water volume measured at the water tank outlet at standard conditions ($WV_{\text{tank-w,sc}}$) is calculated from Equation (42):

$$WV_{\text{tank-w,sc}} = 315.0 \text{ bbl} \times \frac{1}{1.001 \text{ bbl/bbl}} = 314.7 \text{ bbl}$$

The water volume of artificial lift power fluid water at standard conditions ($WV_{\text{pf,sc}}$) is calculated from Equation (15):

$$WV_{\text{pf,sc}} = 300 \text{ bbl} \times \frac{1}{1.002 \text{ bbl/bbl}} = 299.4 \text{ bbl}$$

The water volume total for the production well test at standard conditions ($WV_{\text{tot,sc}}$) is calculated from Equation (40):

$$WV_{\text{tot,sc}} = 314.7 \text{ bbl} + 0.7470 \text{ bbl} - 299.4 \text{ bbl} = 16.00 \text{ bbl}$$

The water volumetric rate total for the production well test at standard conditions ($WVR_{\text{tot,sc}}$) is calculated from Equation (41):

$$WVR_{\text{tot,sc}} = \frac{16.00 \text{ bbl}}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 64.01 \text{ bbl/d}$$

The GOR for the production well test at standard conditions is calculated from Equation (17):

$$\text{GOR} = \frac{46.39 \text{ mscf}}{73.96 \text{ bbl}} \times 1000 = 627 \text{ scf/bbl}$$

The watercut for the production well test at standard conditions (WC_{sc}) is calculated from Equation (18):

$$WC_{\text{sc}} = \frac{16.00 \text{ bbl}}{16.00 \text{ bbl} + 73.96 \text{ bbl}} \times 100 \% = 17.8 \%$$

G.3.3 SI Units

G.3.3.1 Measured Quantities

- Gas volume of the process gas outlet flow meter, at meter conditions ($GV_{\text{proc-g,mc}}$): $0.0850 \times 10^3 \text{ m}^3$.
- Oil volume of the oil tank outlet flow meter, at meter conditions ($OV_{\text{tank-o,mc}}$): 11.92 m^3 .
- Water volume of the water tank outlet flow meter, at meter conditions ($WV_{\text{tank-w,mc}}$): 50.08 m^3 .
- Water volume of the artificial lift power fluid (water) flow meter, at meter conditions ($WV_{\text{pf,mc}}$): 47.70 m^3 .
- Volume fraction of water in the oil/water mixture at standard conditions, obtained from sample analysis ($X_{\text{w,sc}}$): 0.01.
- Duration of production well test (Δt): 6 hours.

G.3.3.2 Known Parameters

- Gas volume correction factor for process gas accounting for phase change of produced gas from meter to standard conditions ($B_{\text{g,proc}}$): $0.06470 \text{ m}^3/\text{m}^3$.

- Oil volume correction factor for oil tank oil accounting for phase change of produced oil from meter to standard conditions ($B_{o,tank-o}$): $1.004 \text{ m}^3/\text{m}^3$.
- Water volume correction factor for oil tank water from meter to standard conditions ($B_{w,tank-o}$): $1.001 \text{ m}^3/\text{m}^3$.
- Water volume correction factor for water tank water from meter to standard conditions ($B_{w,tank-w}$): $1.001 \text{ m}^3/\text{m}^3$.
- Solution GOR of evolved gas (from separator to standard conditions) at standard conditions, per oil volume at standard conditions ($R_{s,tank-o}$): $0.00002 \text{ } 10^3 \text{ m}^3/\text{m}^3$.
- Solution CGR of condensed gas (from process to standard conditions) at standard conditions, per gas volume at standard conditions ($r_{s,proc}$): $0.0000 \text{ m}^3/10^3 \text{ m}^3$.
- Water volume correction factor for artificial lift power fluid water from meter to standard conditions ($B_{w,pf}$): $1.002 \text{ m}^3/\text{m}^3$.
- Pressure of 1.013 bara at standard conditions.
- Temperature of 15.56 °C at standard conditions.
- Oil tank pressure at 1.104 barg.
- Oil tank temperature at 26.0 °C.
- Process pressure (gas meter) at 15.99 barg.
- Process temperature (gas meter) at 33.2 °C.
- Water tank pressure at 1.013 barg.
- Water tank temperature at 26.0 °C.

G.3.3.3 Calculation

The volume fraction of water in the oil/water mixture at the oil tank outlet adjusted to meter conditions ($X_{w,mc}$) is calculated from Equation (16), substituting $B_{w,tank-o}$ (water volume correction factor for oil tank water from meter to standard conditions) for $B_{w,sep}$ and $B_{o,tank-o}$ (oil volume correction factor for oil tank oil accounting for phase change of produced oil from meter to standard conditions) for $B_{o,sep}$:

$$X_{w,mc} = \frac{0.01 \times 1.001 \text{ m}^3/\text{m}^3}{0.01 \times 1.001 \text{ m}^3/\text{m}^3 + (1 - 0.01) \times 1.004 \text{ m}^3/\text{m}^3} = 0.0100$$

The oil volume attributed to oil measured at the oil tank outlet at standard conditions ($OV_{tank-o,sc}$) is calculated from Equation (37):

$$OV_{tank-o,sc} = 11.92 \text{ m}^3 \times (1 - 0.0100) \times \frac{1}{1.004 \text{ m}^3/\text{m}^3} = 11.76 \text{ m}^3$$

The oil volume attributed to oil condensed from gas measured at the process gas outlet at standard conditions ($OV_{proc-g,sc}$) is calculated from Equation (39):

$$OV_{proc-g,sc} = 0.0850 \text{ } 10^3 \text{ m}^3 \times \frac{1}{0.06470 \text{ m}^3/\text{m}^3} \times 0 \text{ m}^3 / 10^3 \text{ m}^3 = 0 \text{ m}^3$$

The oil volume total for the production well test at standard conditions ($OV_{tot,sc}$) is calculated from Equation (35) with oil volume of artificial lift power fluid oil at standard conditions ($OV_{pf,sc}$) equal to zero:

$$OV_{tot,sc} = 11.76 \text{ m}^3 + 0 \text{ m}^3 - 0 \text{ m}^3 = 11.76 \text{ m}^3$$

The oil volumetric rate total for the production well test at standard conditions ($OVR_{tot,sc}$) is calculated from Equation (36):

$$OVR_{tot,sc} = \frac{11.76 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 47.03 \text{ m}^3/\text{d}$$

The gas volume attributed to gas measured at the process gas outlet at standard conditions ($GV_{proc-g,sc}$) is calculated from Equation (32):

$$GV_{proc-g,sc} = 0.0850 \text{ } 10^3 \text{ m}^3 \times \frac{1}{0.06470 \text{ m}^3/\text{m}^3} = 1.313 \text{ } 10^3 \text{ m}^3$$

The gas volume attributed to gas evolved from the oil tank at standard conditions ($GV_{tank-o,sc}$) is calculated from Equation (34):

$$GV_{tank-o,sc} = 11.76 \text{ m}^3 \times 0.00002 \text{ } 10^3 \text{ m}^3/\text{m}^3 = 0.0003 \text{ } 10^3 \text{ m}^3$$

The gas volume total for the production well test at standard conditions ($GV_{tot,sc}$) is calculated from Equation (30) with gas volume of artificial lift gas lift gas at standard conditions ($GV_{gl,sc}$) equal to zero:

$$GV_{tot,sc} = 1.313 \text{ } 10^3 \text{ m}^3 + 0.0003 \text{ } 10^3 \text{ m}^3 - 0 \text{ } 10^3 \text{ m}^3 = 1.313 \text{ } 10^3 \text{ m}^3$$

The gas volumetric rate total for the production well test at standard conditions ($GVR_{tot,sc}$) is calculated from Equation (31):

$$GVR_{tot,sc} = \frac{1.313 \text{ } 10^3 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 5.254 \text{ } 10^3 \text{ m}^3/\text{d}$$

The water volume measured at the oil tank outlet at standard conditions ($WV_{tank-o,sc}$) is calculated from Equation (44):

$$WV_{tank-o,sc} = 11.92 \text{ m}^3 \times 0.0100 \times \frac{1}{1.001 \text{ m}^3/\text{m}^3} = 0.1188 \text{ m}^3$$

The water volume measured at the water tank outlet at standard conditions ($WV_{tank-w,sc}$) is calculated from Equation (42):

$$WV_{tank-w,sc} = 50.08 \text{ m}^3 \times \frac{1}{1.001 \text{ m}^3/\text{m}^3} = 50.03 \text{ m}^3$$

The water volume of artificial lift power fluid water at standard conditions ($WV_{pf,sc}$) is calculated from Equation (15):

$$WV_{pf,sc} = 47.70 \text{ m}^3 \times \frac{1}{1.002 \text{ bbl}/\text{bbl}} = 47.60 \text{ m}^3$$

The water volume total for the production well test at standard conditions ($WV_{\text{tot,sc}}$) is calculated from Equation (40):

$$WV_{\text{tot,sc}} = 50.03 \text{ m}^3 + 0.1188 \text{ m}^3 - 47.60 \text{ m}^3 = 2.544 \text{ m}^3$$

The water volumetric rate total for the production well test at standard conditions ($WVR_{\text{tot,sc}}$) is calculated from Equation (41):

$$WVR_{\text{tot,sc}} = \frac{2.544 \text{ m}^3}{6 \text{ hours} \times \frac{1 \text{ day}}{24 \text{ hours}}} = 10.18 \text{ m}^3/\text{d}$$

The GOR for the production well test at standard conditions is calculated from Equation (17):

$$\text{GOR} = \frac{1.313 \cdot 10^3 \text{ m}^3}{11.76 \text{ m}^3} \times 1000 = 112 \text{ m}^3/\text{m}^3$$

The watercut for the production well test at standard conditions (WC_{sc}) is calculated from Equation (18):

$$WC_{\text{sc}} = \frac{2.544 \text{ m}^3}{2.544 \text{ m}^3 + 11.76 \text{ m}^3} \times 100 \% = 17.8 \%$$

Annex H (informative)

Example Calculations of Production Well Test Use in Allocation

NOTE The following is merely an example for illustration purposes only. It is not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

H.1 Production Well Test Rate Assumed Constant

H.1.1 General

This example shows a calculation of allocated total gas, oil, and water production volume for the duration of an allocation period, based on a constant production well test rate with no applied downtime.

H.1.2 Customary Units

H.1.2.1 Measured Quantities

- Gas volumetric rate total for the production well test at standard conditions ($GVR_{tot,sc}$): 676 mscf/d.
- Oil volumetric rate total for the production well test at standard conditions ($OVR_{tot,sc}$): 1521 bbl/d.
- Water volumetric rate total for the production well test at standard conditions ($WVR_{tot,sc}$): 612 bbl/d.
- Duration of the allocation period (Δt): 744 hours.

H.1.2.2 Calculation

The prorated gas volume for the allocation period at standard conditions ($GV_{alloc-per,sc}$) is calculated from Equation (46):

$$GV_{alloc-per,sc} = 676 \text{ mscf/d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} = 20,942 \text{ mscf}$$

The prorated oil volume for the allocation period at standard conditions ($OV_{alloc-per,sc}$) is calculated from Equation (47):

$$OV_{alloc-per,sc} = 1521 \text{ bbl/d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} = 47,156 \text{ bbl}$$

The prorated water volume for the allocation period at standard conditions ($WV_{alloc-per,sc}$) is calculated from Equation (48):

$$WV_{alloc-per,sc} = 612 \text{ bbl/d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} = 18,983 \text{ bbl}$$

H.1.3 SI Units

H.1.3.1 Measured Quantities

- Gas volumetric rate total for the production well test at standard conditions ($GVR_{tot,sc}$): $19 \times 10^3 \text{ m}^3/\text{d}$.
- Oil volumetric rate total for the production well test at standard conditions ($OVR_{tot,sc}$): $242 \text{ m}^3/\text{d}$.

- Water volumetric rate total for the production well test at standard conditions ($WVR_{tot,sc}$): 97 m³/d.
- Duration of the allocation period (Δt): 744 hours.

H.1.3.2 Calculation

The prorated gas volume for the allocation period at standard conditions ($GV_{alloc-per,sc}$) is calculated from Equation (46):

$$GV_{alloc-per,sc} = 19 \text{ } 10^3 \text{ m}^3/\text{d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} = 593 \text{ } 10^3 \text{ m}^3$$

The prorated oil volume for the allocation period at standard conditions ($OV_{alloc-per,sc}$) is calculated from Equation (47):

$$OV_{alloc-per,sc} = 242 \text{ m}^3/\text{d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} = 7497 \text{ m}^3$$

The prorated water volume for the allocation period at standard conditions ($WV_{alloc-per,sc}$) is calculated from Equation (48):

$$WV_{alloc-per,sc} = 97 \text{ m}^3/\text{d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} = 3018 \text{ m}^3$$

H.2 Production Well Test Rate with Applied Downtime

H.2.1 General

This example shows a calculation of allocated total gas, oil, and water production volume for the duration of an allocation period, based on a constant production well test rate with applied downtime.

H.2.2 Customary Units

H.2.2.1 Measured Quantities

- Gas volumetric rate total for the production well test at standard conditions ($GVR_{tot,sc}$): 676 mscf/d.
- Oil volumetric rate total for the production well test at standard conditions ($OVR_{tot,sc}$): 1521 bbl/d.
- Water volumetric rate total for the production well test at standard conditions ($WVR_{tot,sc}$): 612 bbl/d.
- Duration of the allocation period (Δt): 744 hours.
- Uptime factor (UF): 0.85.

H.2.2.2 Calculation

The prorated gas volume for the allocation period at standard conditions ($GV_{alloc-per,sc}$) is calculated from Equation (49):

$$GV_{alloc-per,sc} = 676 \text{ mscf/d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} \times 0.85 = 17,801 \text{ mscf}$$

The prorated oil volume for the allocation period at standard conditions ($OV_{\text{alloc-per,sc}}$) is calculated from Equation (50):

$$OV_{\text{alloc-per,sc}} = 1521 \text{ bbl/d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} \times 0.85 = 40,083 \text{ bbl}$$

The prorated water volume for the allocation period at standard conditions ($WV_{\text{alloc-per,sc}}$) is calculated from Equation (51):

$$WV_{\text{alloc-per,sc}} = 612 \text{ bbl/d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} \times 0.85 = 16,136 \text{ bbl}$$

H.2.3 SI Units

H.2.3.1 Measured Quantities

- Gas volumetric rate total for the production well test at standard conditions ($GVR_{\text{tot,sc}}$): $19 \times 10^3 \text{ m}^3/\text{d}$.
- Oil volumetric rate total for the production well test at standard conditions ($OVR_{\text{tot,sc}}$): $242 \text{ m}^3/\text{d}$.
- Water volumetric rate total for the production well test at standard conditions ($WVR_{\text{tot,sc}}$): $97 \text{ m}^3/\text{d}$.
- Duration of the allocation period (Δt): 744 hours.
- Uptime factor (UF): 0.85.

H.2.3.2 Calculation

The prorated gas volume for the allocation period at standard conditions ($GV_{\text{alloc-per,sc}}$) is calculated from Equation (49):

$$GV_{\text{alloc-per,sc}} = 19 \times 10^3 \text{ m}^3/\text{d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} \times 0.85 = 504 \times 10^3 \text{ m}^3$$

The prorated oil volume for the allocation period at standard conditions ($OV_{\text{alloc-per,sc}}$) is calculated from Equation (50):

$$OV_{\text{alloc-per,sc}} = 242 \text{ m}^3/\text{d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} \times 0.85 = 6372 \text{ m}^3$$

The prorated water volume for the allocation period at standard conditions ($WV_{\text{alloc-per,sc}}$) is calculated from Equation (51):

$$WV_{\text{alloc-per,sc}} = 97 \text{ m}^3/\text{d} \times \frac{1 \text{ day}}{24 \text{ hours}} \times 744 \text{ hours} \times 0.85 = 2566 \text{ m}^3$$

H.3 Production Well Test Volume Adjustment of Gas Well Continuous Measurement with Single-Phase Meter

H.3.1 General

This example shows a calculation of adjusted production well test gas, oil, and water volumes using production well test information for a gas well continuous measurement with a single-phase meter.

H.3.2 Customary Units

H.3.2.1 Measured Quantities

- Gas volume total for the production well test at standard conditions ($GV_{\text{tot,sc}}$): 45,726 mscf.
- Oil volume total for the production well test at standard conditions ($OV_{\text{tot,sc}}$): 563 bbl.
- Water volume total for the production well test at standard conditions ($WV_{\text{tot,sc}}$): 29 bbl.
- Gas volume of the gas well single-phase flow meter for the duration of the production well test at standard conditions ($GV_{\text{well-test,sc}}$): 48,000 mscf.
- Gas volume of the gas well single-phase flow meter at standard conditions ($GV_{\text{well,sc}}$): 44,000 mscf (this is an example volume, e.g. for one particular day during the allocation period).

H.3.2.2 Calculation

The derived meter correction factor for gas (MCF_g) is calculated following the production well test from Equation (53):

$$MCF_g = \frac{45,726 \text{ mscf}}{48,000 \text{ mscf}} = 0.953$$

The adjusted gas volume of the gas well single-phase flow meter at standard conditions ($AGV_{\text{well,sc}}$) is calculated from Equation (54):

$$AGV_{\text{well,sc}} = 44,000 \text{ mscf} \times 0.953 = 41,915 \text{ mscf}$$

The derived meter correction factor for oil (MCF_o) is calculated following the production well test from Equation (55):

$$MCF_o = \frac{563 \text{ bbl}}{45,726 \text{ mscf}} = 0.012 \text{ bbl/mscf}$$

The adjusted oil volume attributed to the gas volume of the gas well single-phase flow meter at standard conditions ($AOV_{\text{well,sc}}$) is calculated from Equation (56):

$$AOV_{\text{well,sc}} = 41,915 \text{ mscf} \times 0.012 \text{ bbl/mscf} = 516 \text{ bbl}$$

The derived meter correction factor for water (MCF_w) is calculated following the production well test from Equation (57):

$$MCF_w = \frac{29 \text{ bbl}}{45,726 \text{ mscf}} = 0.0006 \text{ bbl/mscf}$$

The adjusted water volume attributed to the gas volume of the gas well single-phase flow meter at standard conditions ($AWV_{\text{well,sc}}$) is calculated from Equation (58):

$$AWV_{\text{well,sc}} = 41,915 \text{ mscf} \times 0.0006 \text{ bbl/mscf} = 27 \text{ bbl}$$

H.3.3 SI Units

H.3.3.1 Measured Quantities

- Gas volume total for the production well test at standard conditions ($GV_{\text{tot,sc}}$): 1295 10^3 m^3 .

- Oil volume total for the production well test at standard conditions ($OV_{\text{tot,sc}}$): 90 m^3 .
- Water volume total for the production well test at standard conditions ($WV_{\text{tot,sc}}$): 5 m^3 .
- Gas volume of the gas well single-phase flow meter for the duration of the production well test at standard conditions ($GV_{\text{well-test,sc}}$): $1359 \text{ } 10^3 \text{ m}^3$.
- Gas volume of the gas well single-phase flow meter at standard conditions ($GV_{\text{well,sc}}$): $1246 \text{ } 10^3 \text{ m}^3$ (this is an example volume, e.g. for one particular day during the allocation period).

H.3.3.2 Calculation

The derived meter correction factor for gas (MCF_g) is calculated following the production well test from Equation (53):

$$MCF_g = \frac{1295 \text{ } 10^3 \text{ m}^3}{1359 \text{ } 10^3 \text{ m}^3} = 0.953$$

The adjusted gas volume of the gas well single-phase flow meter at standard conditions ($AGV_{\text{well,sc}}$) is calculated from Equation (54):

$$AGV_{\text{well,sc}} = 1246 \text{ } 10^3 \text{ m}^3 \times 0.953 = 1187 \text{ } 10^3 \text{ m}^3$$

The derived meter correction factor for oil (MCF_o) is calculated following the production well test from Equation (55):

$$MCF_o = \frac{90 \text{ m}^3}{1295 \text{ } 10^3 \text{ m}^3} = 0.069 \text{ m}^3 / 10^3 \text{ m}^3$$

The adjusted oil volume attributed to the gas volume of the gas well single-phase flow meter at standard conditions ($AOV_{\text{well,sc}}$) is calculated from Equation (56):

$$AOV_{\text{well,sc}} = 1187 \text{ } 10^3 \text{ m}^3 \times 0.069 \text{ m}^3 / 10^3 \text{ m}^3 = 82 \text{ m}^3$$

The derived meter correction factor for water (MCF_w) is calculated following the production well test from Equation (57):

$$MCF_w = \frac{5 \text{ m}^3}{1295 \text{ } 10^3 \text{ m}^3} = 0.004 \text{ m}^3 / 10^3 \text{ m}^3$$

The adjusted water volume attributed to the gas volume of the gas well single-phase flow meter at standard conditions ($AWV_{\text{well,sc}}$) is calculated from Equation (58):

$$AWV_{\text{well,sc}} = 1187 \text{ } 10^3 \text{ m}^3 \times 0.004 \text{ m}^3 / 10^3 \text{ m}^3 = 4 \text{ m}^3$$

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