Manual of Petroleum
Measurement Standards
Chapter 20.1

Production Measurement and Allocation Systems

DRAFT SECOND EDITION, FEBRUARY 2019
# Change Log

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Introduction

This document establishes a framework to develop, implement and manage upstream production measurement and allocation systems. Production measurement and allocation systems addressed in this document refer to the combined application of fluid measurement (flow metering, tank gauging, fluid quality and applied phase behavior) and allocation methodology for the determination of allocated hydrocarbon and water quantities. The intent of this document is to provide operators with a consistent and transparent approach for determining accurate, equitable production allocations.

Additionally, guidance is provided regarding the application of the suite of API Manual of Petroleum Measurement Standards (MPMS) Chapter 20 documents applicable to production measurement and allocation systems, including:

- API MPMS Ch. 20.2 Production Allocation Measurement Using Single-Phase Devices\(^{[11]}\)
- API MPMS Ch. 20.3 Measurement of Multiphase Flow\(^{[12]}\)
- API MPMS Draft Standard Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems
- API MPMS Ch. 20.5 Application of Production Well Testing in Measurement and Allocation

This document is not intended to prescribe a particular fluid measurement or allocation methodology.
Production Measurement and Allocation Systems

1 Scope

This document provides requirements and guidelines for the design and operation of upstream production measurement and allocation systems. This includes identifying requirements, selecting the basis, and defining the methodology, implementation, operation and management of the production measurement and allocation system.

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 applies (including any addenda/errata).

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


3 Terms, Definitions, Abbreviations and Symbols

3.1 Terms and Definitions

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

accumulated quantity(ies)
Fluid quantity(ies) accumulated within the PMAS (e.g. tank inventory, line fill, line pack).

accuracy
The extent to which the results of a calculation or the readings of an instrument approach the true value.

actual conditions
Conditions of pressure and temperature of the fluid at the point where fluid properties (i.e. PVT) or flows are measured or calculated.

allocation end quantity(ies)
PMAS outflow quantity(ies) allocated back to sources as allocated quantity(ies).

allocated quantity(ies)
Quantity(ies) of oil, gas and produced water determined by the allocation process in the PMAS which are assigned to individual allocation source quantity(ies) (e.g. zones, wells, fields, leases, or producing units).

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.
allocation measurement
The measurement of production from individual entities (zones, wells, fields, leases or producing units) in order to determine the percentage of hydrocarbon and associated fluids or energy contents to attribute to each entity, when compared to the total production from the entire system (reservoir, production system, gathering system). It is required when the entities have two or more different working interest owners, or when they have different royalty obligations.

allocation period
A period of time, typically a calendar month, over which an allocation process is applied in the PMAS to determine allocated quantities.

allocation point(s)
Allocation source quantity(ies) physical location and associated thermodynamic state in the PMAS.

allocation point conditions
Allocation point conditions of pressure and temperature.

allocation source quantity(ies)
PMAS inflow quantity(ies) used as the basis to determine theoretical quantity(ies).

allocation tiers
Independent levels of allocation within a production measurement allocation system

bias
Any systematic influence on a result that produces a consistently incorrect approximation of the true value of the variable being quantified.

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.

calibration
A set of operations which establish, under specified conditions, the relationship between the values indicated by a measuring device and the corresponding known values indicated when using a suitable measuring standard.

commingle
To combine the hydrocarbon streams from two or more wells, units, leases, zones, or production facilities into common vessels or pipelines.

consumed quantity(ies)
Fluid quantities consumed as part of the production process associated with the PMAS and not otherwise sold or exported (e.g., fuel, flare, vent).

custody transfer measurement
The measurements specific to a change in ownership and/or a change in responsibility for commodities.

dew point, hydrocarbon
A temperature at a given pressure at which hydrocarbon vapor condensation begins.
diameter ratio
\[ \beta_r \]
The reference orifice plate bore diameter divided by the reference meter tube internal diameter

end point(s)
Allocation end quantity(ies) physical location and associated thermodynamic state in the PMAS.

diameter ratio
The reference orifice plate bore diameter divided by the reference meter tube internal diameter

end point conditions
End point conditions of pressure and temperature.

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 between two or more state functions associated with the material, such as temperature or pressure.

error, measurement
Measured quantity value minus a reference quantity value.

export point
the point in the system where the export quantities are measured and production quantities are attributed to their respective inlet stream

export quantities
the volumetric and thermal quantities of oil, gas and water that are accumulated during the allocation period and attributed to the respective wells, fields, or reservoirs

field
One or more reservoirs all related to the same geological structure.

flash gas factor
\[ FF \]
Ratio of evolved hydrocarbon gas quantity at standard conditions (evolved from hydrocarbon liquid as it is lowered in pressure and temperature from allocation point conditions to end point conditions) to the hydrocarbon liquid quantity at standard conditions.
NOTE 1 Both the evolved hydrocarbon gas and hydrocarbon liquid quantities are adjusted from end point conditions to standard conditions.
NOTE 2 For volume calculations, the flash gas factor is in units of mscf/bbl or \( 10^3 \) m\(^3/\)m\(^3\). For mass calculations, the flash gas factor is in units of lbm/lbm or kg/kg. For molar calculations, the flash gas factor is in units of mol/mol.

gas correction factor
\[ B_{gt} \]
Ratio of hydrocarbon gas quantity at allocation point conditions to the hydrocarbon gas quantity at standard conditions.
NOTE For volume calculations, the gas correction factor is in units of acf/scf or m3/m3. For mass calculations, the gas correction factor is in units of lbm/lbm or kg/kg. For molar calculations, the gas correction factor is in units of mol/mol.
gas lift
The process of hydraulically lifting liquids from a well or a subsea offshore riser by injecting gas in the wellbore or riser respectively.

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

indicated volume
The difference between opening and closing meter readings.

inflow quantity(ies)
Fluid quantity(ies) entering the PMAS

inventory
The oil produced but not exported beyond the allocation end point during the allocation period

material balance
An inventory on the total material (e.g., volume, energy, mass) within a system either at an instant in time or between two instants of time that accounts for material entering and leaving the system, accumulating within the system, or consumed within the system.

NOTE A PMAS material balance does not account for material generation due to the lack of chemical reactions.

measurement
Process of experimentally obtaining one or more quantity values that can reasonably be attributed to a quantity.

molar mass
The mass of one mole of a substance (lbm/mol, kg/mol).

molar volume
The volume occupied by one mole of a substance at a specified temperature and pressure (ft³/mol, m³/mol).

multi-tier allocation
Allocation in two or more tiers, where the first allocation tier is from an allocation end quantity point (e.g. sales point) back to intermediary allocation source quantity points, with subsequent tiers from intermediary allocation source quantity points to the original allocation source quantity points (e.g. wells, fields, leases).

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

oil shrinkage factor

\[ SF \]
Ratio of hydrocarbon liquid quantity at standard conditions to the hydrocarbon liquid quantity at allocation point conditions.

NOTE For volume calculations, the oil shrinkage factor is in units of bbl/bbl or m³/m³. For mass calculations, the oil shrinkage factor is in units of lbm/lbm or kg/kg. For molar calculations, the oil shrinkage factor is in units of mol/mol.
outflow quantity(ies)
Fluid quantity(ies) leaving the PMAS

phase
A term used in the sense of one constituent in a mixture of several. In particular, the term refers to hydrocarbon liquid, hydrocarbon gas, water, or any other constituent in a mixture of any number of these.

pipeline condensate
The liquid formed in a pipeline by a phase change from gas to liquid resulting from a change in temperature and or pressure.

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.

process simulation model
A computer-based model representing physical and chemical processes (mass and energy balances) to predict process conditions, e.g. pressures, temperatures, flows and compositions as well as thermophysical properties, e.g. density, viscosity and heat capacity.

production field
See field.

production quantities
Oil, gas, and water produced from the reservoir and either processed and transported or used/consumed during production processing.

proportional allocation
A method of allocation that attributes the total export quantities to their respective streams based on a proportional ratio of an inlet stream to all the inlet streams.

real gas
A gas containing molecules that occupy space and interact. Real gas properties are described using gas laws that address non-ideal behavior (e.g. ideal gas corrections using a compressibility factor).

reference conditions
The conditions of temperature and pressure to which measured volumes are to be corrected.

reproducibility
Measurement precision under a set of reproducible conditions of measurement.

retrograde condensate
Condensation caused by a decrease in pressure or an increase in temperature.
sampling
All the steps required to obtain a sample that is representative of the contents of any pipe, tank, or other vessel, based on established error, and to place that sample into a container from which a representative test specimen can be taken for analysis.

solution condensate-gas ratio

\[ r_s \]

Ratio of condensed hydrocarbon liquid quantity at standard conditions (condensed from hydrocarbon gas as it is lowered in pressure and temperature from allocation point conditions to end point conditions) to the hydrocarbon gas quantity at standard conditions.

NOTE 1 Both the evolved hydrocarbon gas and hydrocarbon liquid quantities are adjusted from end point conditions to standard conditions.

NOTE 2 For volume calculations, the solution condensate-gas ratio is in units of bbl/mscf or m³/10³ m³. For mass calculations, the solution condensate-gas ratio is in units of lbm/lbm or kg/kg. For molar calculations, the solution condensate-gas ratio is in units of mol/mol.

sediment and water (S&W)
Material that coexists with, yet is foreign to, a petroleum liquid. S&W may include dissolved water, free water, and sediment, and emulsified water and entrained or suspended sediment and water.

separator
A vessel designed to separate the well production stream(s) into two or three distinct phases and streams – liquid (oil/water) and gas streams or water, oil, and gas streams.

single-tier allocation
Allocating directly from gas and liquid hydrocarbon sales points (or reference measurement point) back to each individual well (or source point) in a single step. Compare multi-tier allocation.

standard conditions
Pressure and temperature conditions used to normalize quantities for allocation and/or sales (e.g. 14.696 psia, 60 °F, 101.325 kPa, 15 °C).

standard pressure
Pressure at standard conditions (e.g., 14.696 psia, 101.325 kPa).

standard temperature
Temperature at standard conditions (e.g., 60°F, 15°C).

stream
Any input into a production facility allocation point from a well, reservoir, or field.

theoretical quantity(ies)
PMAS allocation source quantity(ies) adjusted to standard conditions, net of associated circulated, consumed and accumulated quantities.

three-phase
A fluid from a well composed of hydrocarbon liquid, gas, and produced water.
tolerance
The amount of measurement error that will be allowed. It is a plus or minus value.

uncertainty
The range or interval within which the true value is expected to lie with a stated degree of confidence.

vapor pressure
The pressure exerted by the equilibrium vapor of a liquid.

verification
The process or procedure of comparing an instrument to a reference standard to ensure its indication or registration is in satisfactorily close agreement, without making an adjustment.

water correction factor
$B_w$
Ratio of water quantity at allocation point conditions to water quantity at standard conditions.

NOTE For volume calculations, the water correction factor is in units of bbl/bbl or m$^3$/m$^3$. For mass calculations, the water correction factor is in units of lbm/lbm or kg/kg. For molar calculations, the water correction factor is in units of mol/mol.

wet gas
A subset of multiphase flow in which the dominant fluid is gas and in which there is a presence of some liquid.

zone
A formation or horizon (layer of rock) of a well from which reservoir fluids might be produced.

3.2 Abbreviations and Symbols
For the purposes of this document, the following abbreviations and symbols apply.

- bbl: barrels
- EOS: equation of state
- kPa: kilopascal, one thousand pascals
- KPI: key performance indicator
- MPFM: multiphase flowmeter
- MSCF: one thousand standard cubic feet of gas
- psig: pounds per square inch gauge
- PMAS: production measurement and allocation system
- PVT: pressure-volume-temperature
- S&W: sediment and water
- SCF: standard cubic feet of gas
- SF: shrinkage factor
4 Overview of a Production Measurement and Allocation System

4.1 General

Isolated production, processing, and sales of reservoir fluids from a single point of origin is usually not a feasible option for most production operators. Reservoir fluids from varying sources are often commingled within a production process prior to a point of sales. This can be especially true in offshore operations or remote onshore operations where central processing facilities are practical. There is often a difference in taxation (royalty) and ownership among the various production sources, where the reported production from each source has a direct financial impact on producing partners or taxing authorities. Furthermore, the production operator uses reported source production to optimize resource recovery. This creates legal, financial, and management obligations to account for production from each point of origin. Thus, allocation of produced reservoir fluids to the various sources becomes an integral activity in the oil and gas industry.

In an upstream allocation process a material balance is established on a production operation to compare the inflow quantities to outflow quantities in order to equitably assign the final commingled production to the various sources. Typically, the material balance output is export quality gas or oil transferred from the production process facility into a transportation system. This is generally a custody transfer measurement that becomes the reference or official produced quantity for the associated production (usually non-stable fluids), along with the basis for revenue, taxation and transportation fees. The material balance inputs include production at the well or field level, and are determined by the available fluid measurements (e.g. flow, fluid quality) and layout of the producing facilities, ownership or partner arrangements, commercial contractual obligations, and local regulatory directives.

Ensuring the equitable allocation of production quantities requires the establishment and use of a production measurement and allocation system, or PMAS. Figure 1 – Production Measurement and Allocation System Overview shows that a PMAS incorporates two main elements: fluid quantification and an allocation process. Fluid measurement provides quantification of the production fluids within a defined PMAS through the combined utility of metering, tank gauging, fluid quality (e.g. sampling and analysis), and the application of phase behavior or pressure, volume, temperature (PVT) properties. The allocation process provides validation of the production fluid measurements, data handling assurance, and the equitable assignment of commingled production quantities back to the sources.

Figure 1 also highlights the applicability and integration of the suite of API MPMS Chapter 20 documents within the framework of a PMAS.

4.2 Applicability

It is not the intent of this document to specify a meter type, tank gauging method or measurement approach for a PMAS. 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 S&W determination. Additionally, online water determination devices should be capable of measuring the full range of expected water fractions.

The application of single-phase flow metering in a PMAS should follow API MPMS Ch. 20.2 [11].

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 a PMAS should follow API MPMS Ch. 20.3 [12].

The application of water and/or sediment in water determination in a PMAS should follow API MPMS Ch. 10.3 [1] and API MPMS Ch. 10.4 [1].

The application of manual tank gauging in a PMAS should follow API MPMS Ch. 3.1A [1], API MPMS Ch. 18.1 [10] and API MPMS Ch. 18.2.
The application of automatic tank gauging in a PMAS should follow API MPMS Ch. 3.1B [2], API MPMS Ch. 3.3 [3] and API MPMS Ch. 3.6 [4].

The application of temperature and pressure transmitters in a PMAS should follow API RP 551 [15] and API MPMS Ch. 21.1 [13].

NOTE For the application of online water determination devices in a PMAS, refer to API TR 2570 [16].

Figure 1 – Production Measurement and Allocation System Overview
There are several types of liquid and gas sampling systems or procedures that are available for use in a PMAS. It is not the intent of this document to specify a sampling system or procedure for a PMAS. 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. All parties involved should agree to the sampling methods and procedures used for a PMAS. Applicable standards that may be referenced for liquid sampling in a PMAS include API MPMS Ch. 8.1 [5], API MPMS Ch. 8.2 [6], and API RP 87 [14].

An applicable standard that may be referenced for gas sampling in a PMAS is API MPMS Ch. 14.1 [9].

NOTE At the time of publication of this document there are no industry standards on multiphase flow sampling and analysis, or sampling and analysis of unstablized fluids. Additionally, with the exception of API RP 87, the sampling standards referenced were not written for direct application in a PMAS 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.

### 4.3 PMAS Business Process Workflow

Establishing and maintaining a PMAS shall incorporate development, implementation, and operational activities that ensure the PMAS is capable of meeting allocation requirements. Key elements that shall be performed to establish and maintain a PMAS include:

- Identify PMAS requirements (Section 5),
- Select basis of allocation (Section 6),
- Define allocation process (Section 7),
- Implement PMAS (Section 8),
- Operate and manage PMAS (Section 9).

Figure 2 – PMAS Business Process Workflow outlines the key elements, the associated work flow and supporting activities used to establish and maintain a PMAS.
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Figure 2 – PMAS Business Process Workflow
5 Identify Production Measurement and Allocation System Requirements

5.1 General

The primary outputs of a PMAS are reported volumes, masses, or energy quantities attributed to a field, lease, well, or zone. Requirements for the frequency, accuracy, and granularity of the reported quantities are generally defined by three groups of stakeholders: regulators, contractual parties, and operator organizations. These requirements are then often cited in regulatory permits, commercial agreements and operator's policies. The application of this document shall be in compliance with all applicable regulations, and in conformance with permits and agreements.

All PMAS requirements outlined in regulations, permits or agreements shall be documented.

5.2 Roles and Responsibility

Production allocation, including the establishment and maintenance of a PMAS shall be the responsibility of the operator.

PMAS development, implementation, operation and management may be conducted by the operator or contracted to a service company which specializes in production allocation.

5.3 Governmental Requirements

Regular reports of allocated production from oil and gas wells are required by federal, state and local authorities. There are several reasons why governmental agencies require allocated quantities. In states with proration laws, and on federal lands, well rates are reported to provide conservation commissions, mineral management offices and regulatory bodies with data necessary for establishing production rates which 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 allocated quantities sometimes serving as a basis for tax determination. Governmental agencies can stipulate the method for allocating quantities and the frequency of reporting.

A PMAS used to generate reported data shall be documented and consistent with the applicable regulations and statutes.

5.4 Commercial and Royalty Agreements

Similar to regulatory requirements, commercial agreements can stipulate the method of allocating quantities, and the frequency of reporting. A PMAS shall be documented and consistent with the applicable agreements. If not already addressed by an applicable agreement, the information and requirements contained in this document can be used to derive documentation supplementary to the agreement.

5.5 Reservoir/Production Management

Allocated quantities are a key input for reservoir management, production optimization and flow assurance. A PMAS should include documented requirements for reservoir, production optimization and flow assurance management.
5.6 Acceptance Criteria

Acceptance criteria for use in PMAS evaluation shall be established and documented prior to PMAS implementation. The acceptance criteria should be based on consideration of the entire PMAS (e.g. fluid quantification and allocation process). Section 9.5 provides various acceptance criteria for consideration.

6 Select Basis of Allocation

6.1 General

Requirements to allocate production quantities from stabilized measurement points back to a well or reservoir level are determined from regulatory, commercial and reservoir/production management requirements as discussed in Section 5. An important first step in addressing the allocation requirements in the development of a PMAS is establishing the basis of allocation, including:

- Fluids to allocate (Section 6.2),
- Frequency of allocation (Section 6.3),
- Engineering Units (Section 6.4),
- Material balance (Section 6.5).

6.2 Fluids to Allocate

Fluids to allocate shall be selected and documented based on stated PMAS requirements. This shall include:

- Fluid type (e.g. oil, gas, condensate, water),
- Fluid quantities (e.g. volume, mass, molar volume, molar mass, energy).

6.3 Frequency of Allocation

Frequency of allocation (alternatively, allocation period) shall be selected and documented based on stated PMAS requirements (e.g. daily, weekly, monthly, yearly).

NOTE The operator may choose to allocate at a different frequency in addition to what is required for statutory or contractual purposes.

6.4 Engineering Units and Physical Constants

Engineering units shall be selected and documented based on stated PMAS requirements to include:

- Units of measure (e.g. m³, bbl, mscf, psig, °F),
  NOTE Units of measure shall be clearly stated at the applicable process conditions (e.g., actual conditions, standard conditions).
- Standard conditions (e.g. 14.696 psia, 60 °F, 101.325 kPa, 15 °C),
- Unit conversion factors (e.g. 1 m³ = 6.29 bbls),
- Physical constants (e.g. relative density).
  NOTE GPA 2145 [17] provides physical properties of selected hydrocarbons.

A consistent set of units should be used throughout the PMAS.
6.5 Material Balance

6.5.1 General

A material balance shall be established for a PMAS, based on the following equation (refer to Figure 3 – PMAS Material Balance):

\[ \text{Inflow Quantities} = \text{Outflow Quantities} + \text{Consumed Quantities} + \text{Accumulated Quantities} \] (1)

NOTE Depending on the measurement points and PMAS boundaries, PMAS inflow and outflow can include circulated quantities. It is important when delineating the PMAS material balance to accurately account for recirculated flows.

![Figure 3 – PMAS Material Balance](image)

The material balance shall be used to determine:

- PMAS boundaries, including commingled points to be allocated from (i.e., outflow quantities) and sources to be allocated to (i.e., inflow quantities),
- Formulation basis for theoretical and allocated quantities (refer to Sections 7.5 and 7.6 respectively),
- Allocation tiers (refer to Section 7.3) and allocation methodology (refer to Section 7.6).
The type of material balance shall be defined based on the fluids to allocate (refer to Section 6.2). Material balance types include:

- Volume balance,
- Energy balance,
- Mass balance.

Volumetric changes and phase conversions (i.e. mass transfer to and from gas and liquid hydrocarbons) shall be accounted for in a PMAS material balance. For example, a volume balance shall be at a consistent pressure and temperature (e.g. standard conditions) with the corresponding phase conversions applied. A mass balance on a hydrocarbon production process shall include all hydrocarbon flows in a PMAS (liquid and gas).

NOTE Volumetric changes and phase conversions (i.e. mass transfer to and from gas and liquid hydrocarbon) are inherent to hydrocarbon processing in an upstream PMAS. As hydrocarbon liquid inflow continues through the production process from elevated temperatures and pressures to standard conditions, 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. As such, accounting for volumetric changes and phase conversions is necessary to ensure an accurate material balance.

Each type of material balance shall use fluid quantity and composition data applicable to the process conditions. Inflow quantities, outflow quantities, consumed quantities and accumulated quantities shall be determined as established for fluids to allocate (refer to Section 6.2), including fluid type and quantity.

During the development of a PMAS material balance, a measurement and allocation process flow diagram (MAPFD) should be developed, with a clear delineation of the sources to be allocated to (i.e. inflow quantities) and the commingled points from which they are being allocated (i.e., outflow quantities). The MAPFD can evolve to a finalized version (as described in section 8.2) prior to implementation of a PMAS.

The MAPFD should be used to identify fluid quantification points necessary for a PMAS that are not physically present or included in the design of the applicable hydrocarbon production process. The MAPFD can then be used to justify opportunities to add the fluid quantification points to the hydrocarbon production process. In addition, the MAPFD can be used to inform decisions on location of commingling points in the hydrocarbon production process.

NOTE For example, several locations might be available to tie third party production into an existing production process. The MAPFD can be used to show a tie-in location that provides minimal impact to a PMAS.

**6.5.2 Inflow Quantities**

All inflow quantities for a PMAS shall be identified and included in the material balance. Examples of PMAS inflow quantities include:

- Wells (individually or commingled),
- Fields (individually or commingled),
- Buyback oil and gas,
- Recycled flows such as gas lift gas and flow assurance oil,
- Externally supplied fuel gas.

NOTE Well inflow quantities are addressed in API MPMS Ch. 20.5. Field inflow quantities are typically measured at the separator level, or can be a combination of individual measurements such as summed well inflows.
6.5.3 Outflow Quantities

All outflow quantities for a PMAS shall be identified and included in the material balance. Examples of PMAS outflow quantities include:

- Export oil and gas (e.g., sales),
- Produced water,
- Recycled flows such as gas lift and flow assurance oil,
- Exported fuel gas.

6.5.4 Consumed Quantities

All consumed quantities for a PMAS shall be identified and included in the material balance. Examples of PMAS consumed quantities include:

- Fuel gas,
- Flare gas,
- Vent gas.

6.5.5 Accumulated Quantities

All accumulated quantities for a PMAS shall be identified and included in the material balance. Examples of PMAS accumulated quantities include:

- Oil tank inventory,
- Line fill,
- Line pack.

NOTE Accumulated quantities as defined and used in the material balance equation can be positive or negative amounts, depending on flow paths during the allocation period. For example, if there is net accumulation in oil inventory tanks filled with inflow production during the allocation period, then the accumulated quantity is positive (the oil does not leave the PMAS through outflow, and therefore is accounted for as a positive quantity to balance the PMAS material balance equation). If there is a net discharge of oil inventory tanks to outflow during the allocation period, then the accumulated quantity is negative (the oil does leave the PMAS through outflow, and therefore is accounted for as a negative quantity to balance the PMAS material balance equation).

7 Define Allocation Process

7.1 General

A PMAS allocation process shall be defined once a basis of allocation is selected. An allocation process should include the following elements to determine the allocated quantities of a PMAS (refer to Figure 4):

- Allocation tiers (Section 7.3),
- Allocation process inputs and outputs (e.g., allocation source quantities, allocation end quantities, and allocated quantities) (Section 7.4),
- Procedures and formulations for the determination of theoretical quantities (Section 7.5),
- Allocation method for the determination of allocated quantities (Section 7.6).

NOTE Figure 4 is a simplified example of a single-tier allocation process applied to a single set of allocation source quantities (i.e. inflow quantities from the material balance) and a single allocation end quantity (i.e. outflow quantity from the material balance). If more than one allocation tier is used, each allocation tier will incorporate separate allocation process inputs, outputs, along with theoretical quantity formulations and allocation method (refer to 7.6).
Elements of the allocation process are specified based on a PMAS material balance (refer to Section 6.5.1). Elements should be specified as simply as practical and shall provide allocation process results in accordance with Section 5 that are equitable and auditable. An equitable allocation process shall not contain an identified bias that has not been mitigated and agreed upon by affected parties. An auditable allocation process shall provide information (i.e., inputs, procedures and formulations, methods) that can be independently evaluated in a step-wise manner to achieve the same results.

The PMAS allocation process should be defined before the design and selection of fluid quantification systems used in the PMAS. This allows parties involved to select and install viable fluid quantification systems for the PMAS that are compatible with the defined allocation process and avoid compromises in PMAS performance.

### 7.2 Considerations for Defining an Allocation Process

#### 7.2.1 Fluid Similarity

Developers of the PMAS should consider the similarity of the source fluids when developing the allocation process. In general, similar fluids require less rigor in an allocation process as impacts from bias...
associated with fluid properties are small. Conversely, dissimilar fluids may require more rigorous approaches to address these impacts.

The following list provides a starting point for the establishment of source fluid dissimilarity. The listed dissimilarity is an approximation of the point where fluids would be considered dissimilar. Any one property can establish dissimilarity. The developer should establish these dissimilarities through parameter variability or sensitivity analyses of the source streams and document the results.

<table>
<thead>
<tr>
<th>LIQUID PROPERTY</th>
<th>DISSIMILARITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>API GRAVITY</td>
<td>Greater than 10 % of the value of any one stream</td>
</tr>
<tr>
<td>SHRINKAGE</td>
<td>Greater than a 5 % volume loss difference between any two streams</td>
</tr>
<tr>
<td>C7+ MOLE PERCENT</td>
<td>Greater than a 20 % difference between the mole percent of any two streams</td>
</tr>
<tr>
<td>GAS / OIL RATIO</td>
<td>Greater than 100 % of the value of any one stream</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>GAS PROPERTY</th>
<th>DISSIMILARITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>METHANE MOLE PERCENT</td>
<td>Greater than a 5 mole% difference between any two streams</td>
</tr>
<tr>
<td>C7+ MOLE PERCENT</td>
<td>Greater than 100 % of the value of any one stream</td>
</tr>
<tr>
<td>CONDENSATE / GAS RATIO</td>
<td>Greater than 100 % of the value of any one stream</td>
</tr>
</tbody>
</table>

7.2.2 Bias

The PMAS shall be defined such that no known and avoidable bias introduces an inequitable allocation among the parties participating in the PMAS. PMAS bias that is determined to be unavoidable shall be thoroughly described, quantified, documented and mutually agreed by all parties participating in the PMAS.

PMAS bias shall be identified by evaluating potential sources including:

- Fluid quantification (e.g. measurement device uncertainty, fluid properties),
- Theoretical quantity determination (e.g. equations, application of phase behavior),
- Allocated quantity determination (e.g. allocation method),
- Procedures (e.g. sampling, fluid property determination and validation),
- Input data validation (e.g. meter values, temperatures, pressures),
- System configurations (e.g. data handling, flow computers),
- Process equipment operation (e.g. separator efficiency, rangeability of measurement devices),
- Allocation staff competency (e.g. level of training, awareness).
Refer to Annex A or Annex B for examples of potential PMAS bias.

Eliminating or mitigating bias during PMAS definition is contingent on the type of bias, and how the bias is introduced within the PMAS. For example, systematic measurement bias can be eliminated procedurally through device calibration or through process design by removal of installation effects. Alternatively, unavoidable relative differences among random uncertainties associated with measurement systems used to derive allocation source theoretical quantities used in a proportional allocation can be addressed through the uncertainty-based allocation methodology as detailed in API RP 85. In addition, PMAS developers should be trained and periodically assessed for competency, and all PMAS development documentation should be clear and fully articulated to allow for transparency among all parties participating in the PMAS. Finally, the PMAS should be defined with performance monitoring and surveillance elements that enable early detection of bias (refer to Section 9.5).

NOTE The control of bias is a key consideration in defining the PMAS allocation process. The performance of a PMAS is often judged by how well the total theoretical quantities determined in the allocation process match the actual quantities to be allocated (the allocation factor KPI; refer to Section 9.5). When these values match well, it is seen as an indication that the fluid quantification systems and allocation process are working well. However, biases within the PMAS might be offsetting and not obvious in a total system level PMAS allocation factor. In this scenario, a PMAS can be functional but not equitable. A small difference between theoretical and allocated quantities can be inequitable and unacceptable if the difference causes the same party to be shorted allocated quantities continually over multiple allocation periods.

### 7.2.3 Continuous vs Periodic Fluid Quantification

Continuous fluid quantification should be specified over periodic fluid quantification (if practical) during the design of the fluid quantification systems used in the PMAS. Additionally, continuous fluid quantification throughout the allocation period should take precedence over periodic fluid quantification when both are applied for the same fluid within the boundaries of a PMAS (provided the difference in uncertainty between the two fluid quantification techniques is negligible, as determined by defined acceptance criteria).

NOTE Continuous fluid quantification throughout the allocation period reflects operational changes and typically provides more accurate results than periodic fluid quantification. Periodic fluid quantification requires the application of an operating time or adjustment factors to determine the total quantity for the allocation period. Both operating time and adjustment factors can be difficult to accurately assess, resulting in higher uncertainty for periodic fluid quantification during the allocation period.

### 7.2.4 Consistency in Fluid Quantification

If practical, allocation sources within a PMAS allocation tier (refer to Section 7.3) should use the same type of fluid quantification system. When different fluid quantification systems are used, or when using the same type of quantification system creates a bias, the relative uncertainty among the fluid quantification systems shall be addressed in the development of the allocation method (refer to Section 7.3).

### 7.2.5 Accounting for Phase Behavior among Dissimilar Allocation Source Fluid Types

The phase behavior effects due to commingling of dissimilar PMAS source fluids (e.g. black oil versus gas/condensate) shall be addressed in the development of the theoretical quantity procedures and formulations. Use of a process simulation model incorporating an equation of state to account for the phase behavior due to commingling of dissimilar source fluids shall be in accordance with API Draft Standard Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems.

NOTE Applied phase behavior in a PMAS typically consists of field or laboratory PVT measurements applicable to individual source fluids. These analyses do not address the effect on the phase behavior of commingled source fluids (i.e. mass transfer in the commingled fluids). The commingled fluid phase behavior effects on shrinkage, flash gas,
condensation and energy content are small when the commingled fluids have similar compositions. When there is a disparity in fluids, ignoring the commingling effect can create a bias in a PMAS.

7.2.6 Allocation of Gas on a Volume and Energy Basis

The operator should apply a source gas heat value to a source gas quantity when converting source gas volume to energy or the operator should determine source gas volume and energy independently. A heat value derived from the commingling of source streams should not be used.

When taken in summation, the allocated quantities to sources will have a heat value (energy/unit volume) equal to the sales gas heat value. However, when evaluated alone, the heat value of the individual sources will not equal the sales gas heat value or the other source heat values. This could only occur if all the fluids handled by the PMAS were identical. Allocating gas volume by applying a sales gas heat value to an allocated energy will skew the volume allocation results for the source. Conversely, allocating energy by applying a sales gas heat value to an allocated source volume will skew the source energy allocation results.

Given that there are many stakeholders in the allocation process, it is important that gas volume and energy are reported as accurately as possible. The information required to perform the allocation using source gas heat values or calculating both volume and energy allocations independently is typically available within the data already gathered to perform the allocation.

7.3 Allocation Tiers

An allocation tier is an independent level of allocation within a PMAS. An allocation tier should include:

- Allocation process inputs and outputs (i.e. allocation source quantities, allocation end quantities, and allocated quantities),
- Procedures and formulations for the determination of theoretical quantities,
- Allocation method for the determination of allocated quantities.

A PMAS might be adequately addressed with a single allocation tier, or require a multi-tier approach. In a multi-allocation tier PMAS, the allocation process outputs from one tier shall become the allocation process inputs for the next tier. Each allocation tier may use different procedures and formulations for the determination of theoretical quantities, and different allocation method.

Figure 4 represents a single allocation tier. Frequently a PMAS will require multiple allocation tiers to address differences in fluid quantification systems, groupings of ownership, and introduction of allocation source quantities into the system at different production process points (refer to Figure 5).

Generally, the use of multi-tier allocation reduces overall uncertainty with respect to the assignment of allocation end quantities to the individual allocation sources. The PMAS allocation process should use the number of allocation tiers necessary to reduce system uncertainty to the lowest extent necessary to achieve equitable and acceptable results.
Figure 5 – Example PMAS Two-Tier Allocation System
7.4 Allocation Process Inputs and Outputs

7.4.1 Allocation Source and End Quantities

Allocation source quantities shall be PMAS inflow quantities used as the basis to determine theoretical quantities for the allocation (i.e. incorporated as inputs to the allocation process). In the allocation, sources can include wells, reservoir levels, accumulated quantities, and external production streams. Allocation source quantities and the associated thermodynamic state are often referred to as allocation points.

Allocation end quantities shall be PMAS outflow quantities allocated back to sources as allocated quantities (i.e. outputs of the allocation process), based on theoretical quantities. The allocation end quantities can include sales gas quantities, LACT quantities, consumed and accumulated quantities. Allocation end quantities and the associated final thermodynamic state are often referred to as end points.

In a multi-tier allocation PMAS (refer to Section 7.3), allocation source quantities may extend to intermediate fluid quantification points in a hydrocarbon production process such as meters on the outlet of inlet separators or a well pad meter. The allocated quantity to an allocation source quantity in a higher-level allocation tier shall become the allocation end quantity in a lower-level tier.

7.4.2 Consumed and Accumulated Quantities

Consumed and accumulated quantities (inputs) shall be addressed in the allocation when such quantities have a material impact on the allocation outcome as determined by the defined acceptance criteria.

Consumed quantities are quantities from sources consumed as part of the production process and not otherwise sold or exported (refer to Section 6.5.4). Examples of consumed quantities include fuel gas and flare. Consumed quantities are used in the determination of net theoretical quantities from gross theoretical quantities (refer to Section 7.5.8).

Accumulated quantities are quantities from sources produced in an allocation period and sold or exported in another allocation period (refer to Section 6.5.5). An example of accumulated quantity is oil tank inventory. Accumulated quantities are used in the determination of net theoretical quantities from gross theoretical quantities (refer to Section 7.5.7).

7.4.3 Allocated Quantities

Allocated quantities, or PMAS outputs are quantities allocated back to allocation sources. Allocated quantities are the result of the application of the allocation method applied to the theoretical quantities and allocation end quantities (refer to Section 7.6).

NOTE Measured or calculated theoretical water quantities can be directly assigned back to sources without applying an allocation method to a total allocation end quantity of water, when the end quantity is unavailable (i.e. not measured). Gathered water quantities that are measured or calculated as an allocation end quantity are allocated back to the sources on a proportional basis (refer to Section 7.6.2).

7.4.4 Production Process Conditions and Input Quantities

7.4.4.1 General

When allocation source quantities correspond with the outflow of two or three phase separation, the source liquid is at or near bubble point and the source gas is at or near hydrocarbon dew point (at the corresponding process pressure and temperature). As the liquid continues through the process to a lower endpoint pressure and temperature, light hydrocarbon components evolve out resulting in a reduction of liquid quantity. Conversely, heavier hydrocarbon components condense out of the gas, causing a reduction in gas quantity. Water, if present, is also removed from both the liquid and gas quantities.
Inputs to the PMAS include the measured or calculated allocation source quantities and shall incorporate applied phase behavior, or PVT factors, to account for the quantity changes associated with the phase conversions. The input allocation source quantities can be stated as volume, mass, molar, or energy. The PVT factors are dependent on process conditions of pressure and temperature, and fluid composition.

NOTE Typically, allocation source quantities are the only PMAS inputs that experience a phase conversion. However, there might be situations where additional PMAS input quantities will require applied phase behavior, such as non-stable liquid hydrocarbons used as a circulated flow or non-stable gas used in gas lift.

### 7.4.4.2 Liquid Volume Inputs

Non-thermodynamically stable liquid quantities input into the PMAS as volumes shall be stated at actual conditions. A non-thermodynamically stable liquid quantity is defined with a bubble point above standard pressure at standard temperature. Theoretical liquid volumes shall be corrected to standard conditions after the volume adjustment for phase conversion has been applied (i.e. the liquid is thermodynamically stable; refer to eqn x).

NOTE API MPMS Ch. 11.1 determines volume correction factors used to correct liquid volume at actual conditions (observed) to volume at standard conditions. The volume correction factors are intended to be applied to single-phase hydrocarbon liquids (e.g. crude oils, refined products, lubricating oils) stabilized for transportation, and are derived from empirical analysis of pressure and temperature correction data obtained on stabilized, single-phase liquid hydrocarbons. Hydrocarbon liquid densities used in the volume correction factor calculations do not account for liquids subject to a phase conversion (i.e. API MPMS Ch. 11.1 calculated densities for non-stable hydrocarbon liquids at standard conditions are not the actual density of the hydrocarbon liquid at standard conditions). Thus, applying API MPMS Ch. 11.1 volume correction factors in a PMAS derived from inaccurate densities of non-stable liquid hydrocarbons at standard conditions potentially introduces a bias in the calculated volume.

### 7.4.4.3 Gas Volume Inputs

Non-thermodynamically stable gas quantities input into the PMAS as volumes shall be stated at actual conditions as a real gas. A non-thermodynamically stable gas quantity is defined as a gas that produces liquid condensate when processed from allocation point conditions to end point conditions. Theoretical gas volumes shall be corrected to standard conditions after the volume adjustment for phase conversion has been applied.

NOTE The calculation to correct a gas volume from actual conditions to standard conditions requires the inclusion of gas compressibility factor (Z). The gas compressibility factor is a function of gas composition and is typically calculated in a gas meter flow computer. Gas composition changes with phase conversion between input actual conditions of pressure and temperature and conditions of pressure and temperature at the end point. Thus, applying a compressibility factor based on the gas composition of input pressure and temperature conditions (i.e. actual conditions at the measurement point) in a PMAS instead of a compressibility factor based on the gas composition at end point pressure and temperature conditions (i.e. after phase conversion) potentially introduces a bias in the calculated volume.

When agreed by affected parties, an operator may state PMAS gas volume inputs at standard conditions if it can be demonstrated that there is no phase conversion when the gas is processed from allocation point conditions to PMAS end point conditions, or that the phase conversion does not materially impact the allocation.

NOTE In a PMAS, a procedure that adjusts gas quantities at allocation point conditions directly to standard conditions, either by calculation or physical means, will result in a different quantity than a procedure that accounts for end point conditions, then adjusts to standard conditions. It is only when there is no phase change (i.e. mass transfer) between allocation point conditions and standard conditions that the two procedures can be considered equivalent. The resulting quantity differential between the two procedures potentially becomes larger as gas processing conditions move towards higher pressures and temperatures relative to standard conditions.
7.4.4.4 Mass and Molar Inputs

Hydrocarbon mass and molar input quantities in a PMAS are not affected by the stated pressure and temperature conditions. However, loss of mass or moles through phase conversion shall be applied to PMAS input quantities to account for phase conversion from allocation point conditions of pressure and temperature to end point conditions of pressure and temperature.

7.4.5 PVT Fluid Properties Applied to Input Quantities

7.4.5.1 General

To account for volumetric and mass changes due to phase conversions in the PMAS, the following PVT factors shall be applied to inputs in the determination of measured theoretical quantities:

- Oil shrinkage factor, $SF$;
- Gas correction factor, $B_g$;
- Water correction factor, $B_w$;
- Flash gas factor, $FF$;
- Solution condensate-gas ratio, $r_s$.

If phase behavior cannot be easily represented by $SF$, $B_g$, $FF$, 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 $SF$, $B_g$, $FF$, and $r_s$ as applicable in a PMAS (i.e., at allocation point conditions) 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 allocation point conditions);
3. multistage separator test for determination of total $SF$ and $FF$ relative to reservoir conditions of pressure and temperature (not allocation point conditions, 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 $SF$ and $FF$ relative to reservoir conditions of pressure and temperature (not allocation point conditions) that are used to determine the total $SF$ and $FF$ (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 allocation point conditions). As such, determination of $SF$, $B_g$, $FF$, and $r_s$ for allocation 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 allocation point. For more information on PVT studies and analysis, refer to the SPE test Phase Behavior<ref>.

NOTE 2 $SF$, $B_g$, $B_w$, $FF$, and $r_s$ as applicable in measured theoretical quantity determination (i.e., at allocation point conditions) 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 measured theoretical quantity calculations can result if these properties are not properly determined, such as high-pressure and high-temperature applications of separators or multiphase flow meters. Conversely, $SF$, $B_g$, $B_w$, $FF$, and $r_s$ might not be of enough significance to use in measured theoretical quantity 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 measured theoretical quantity result.
7.4.5.2 Oil Shrinkage Factor, \( SF \)

The oil shrinkage factor, or \( SF \), is the ratio of hydrocarbon liquid quantity at standard conditions to the hydrocarbon liquid quantity at allocation point conditions.

**NOTE 1** For reservoir engineering calculations using volume, the oil shrinkage factor \( SF \) is the inverse of the oil volume correction factor, \( B_o \) (i.e., \( SF = 1/B_o \)).

**NOTE 2** For volumetric oil shrinkage due to blending of stabilized light hydrocarbon liquids (581.0 kg/m\(^3\) to 889.0 kg/m\(^3\), 112.0 °API to 27.6 °API) with stabilized crude oil (644.0 kg/m\(^3\) to 979.0 kg/m\(^3\), 88.2 °API to 13.0 °API) near 15 °C (60 °F) and between 100 kPa to 700 kPa (15 psia to 115 psia), refer to API MPMS Ch. 12.3[8].

\( SF \) shall be determined and applied to account for mass transfer of liquid hydrocarbons between the thermodynamic states represented by the allocation point and the end point, with end point quantities adjusted to standard conditions. For liquid hydrocarbons, the final point of liquid/vapor separation in the production process (e.g. a dry oil tank) prior to measurement and determination of allocation end quantities shall be the end point. \( SF \) shall be used to adjust PMAS input hydrocarbon liquid quantities to standard conditions to match the reported allocation end quantities (e.g. LACT tickets report oil volume at standard conditions). To avoid bias in the PMAS, \( SF \) determination among commingled allocation point fluids shall be consistently implemented and applied for each commingled fluid.

In general, \( SF \) is determined by the following equation:

\[
SF = \frac{Q_{o,sc}}{Q_{o,apc}} \tag{2}
\]

Where:
- \( SF \) is oil shrinkage factor;
- \( Q_{o,sc} \) is quantity of liquid hydrocarbon at standard conditions;
- \( Q_{o,apc} \) is quantity of liquid hydrocarbon at allocation point conditions.

For a volume-based \( SF \), the \( Q_{o,sc} \) is determined by the following equation:

\[
Q_{o,sc} = Q_{o,epc} \times VCF \tag{3}
\]

Where:
- \( Q_{o,sc} \) is volume of liquid hydrocarbon at standard conditions (bbl, m\(^3\));
- \( Q_{o,epc} \) is volume of liquid hydrocarbon at end point conditions (bbl, m\(^3\));
- \( VCF \) is volume correction factor (CPL and/or CTL) as addressed in API MPMS Ch. 11.1, from end point conditions to standard conditions.

For a mass or molar-based \( SF \), the quantity of oil at standard conditions, \( Q_{o,sc} \), is equal to the quantity of oil at end point conditions, \( Q_{o,epc} \), as it is assumed that no mass transfer of hydrocarbon has occurred (i.e. the conditions are thermodynamically equivalent).

\( SF \) shall be determined from one the following methods:

- **Laboratory Measurement.** A sample of produced hydrocarbon liquid at allocation point conditions is subject to reduction in pressure and temperature to end point conditions. The \( SF \) is determined as the ratio of measured hydrocarbon liquid quantity at end point conditions, adjusted to standard conditions (i.e. \( Q_{o,epc} \)), to the measured hydrocarbon liquid quantity at allocation point conditions (i.e. \( Q_{o,apc} \)). For volumetric \( SF \) determination, the measured volume of liquid hydrocarbon at end point conditions (i.e. \( Q_{o,epc} \)) is adjusted with volume correction factors (CPL and CTL as addressed...
in API MPMS Ch. 11.1) to standard conditions (refer to eqn x). Mass or molar based measurements following phase conversion are reported at standard conditions.

NOTE Some laboratories might flash the sample to ambient conditions (in lieu of end point conditions, with an applied VCF for volume $SF$ calculations). When agreed by affected parties, a laboratory determination of $SF$ directly to ambient conditions might be acceptable if it can be demonstrated that there is no bias introduced among the commingled allocation source quantities.

$SF$ can be determined in a single-stage flash or under multistage flash conditions. Depending on the production process between the allocation point and the end point, a multistage flash can lead to a more accurate determination of $SF$. $SF$ is generally determined in the laboratory at the same time as $FF$.

A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e., major liquid/vapor separation stages) between the allocation point and the end point.

- **Calculation.** A sample of produced hydrocarbon liquid at allocation point conditions is subject to analysis to obtain the total hydrocarbon composition. EOS modeling using the hydrocarbon composition and either a simulated single-stage or multistage flash calculation from allocation point conditions to end point conditions, adjusted to standard conditions, can provide a calculated estimate of $SF$. For volumetric $SF$ determination, the calculated volume of liquid hydrocarbon at end point conditions (i.e. $Q_{o, ep}$) is adjusted with volume correction factors (CPL and CTL as addressed in API MPMS Ch. 11.1) to standard conditions (refer to eqn x). Mass or molar based measurements following phase conversion are reported at standard conditions.

NOTE EOS modeling software packages can typically report results of the simulated flash calculation to end point conditions at standard conditions (i.e. the volume correction is addressed in the software).

NOTE EOS modeling might be used for flash calculations to ambient conditions (in lieu of end point conditions). When agreed by affected parties, an EOS determination of $SF$ directly to ambient conditions might be acceptable if it can be demonstrated that there is no bias introduced among the commingled allocation source quantities.

A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major liquid/vapor separation stages) between the allocation point and the end point.

The EOS shall 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.** $SF$ can be determined in the field with the procedure outlined in Annex E.

Refer to Figure 6 for additional description of $SF$ determination.

NOTE The varying methods to determine $SF$ present the operator with a question as to which option is preferred. As with all aspects of PMAS design and operation, the goal is to avoid bias that introduces an inequitable allocation among the participating parties (refer to Section 7.2.2). Thus, choice on a $SF$ determination methodology depends on a preliminary evaluation of the commingled fluids within the PMAS, and if $SF$ determination might potentially create a bias. If the allocation source quantity fluid properties are demonstrated to have different PVT properties (e.g. black oils commingled with volatile oils) and remain relatively stable over time (i.e. allocation point conditions are consistent and compositionally each fluid is unchanging), then bias can be eliminated by a thorough PVT analysis on each allocation source quantity fluid using laboratory measurements on an infrequent basis (e.g. validated annually). Conversely, if allocation point conditions are variable and/or allocation source quantity fluid compositions change for each allocation period, comprehensive PVT analysis through laboratory measurements might not be feasible for each allocation period (e.g. monthly). In this case, updating allocation point conditions and allocation source quantity fluid compositions in an EOS calculation can be used to prevent bias. Alternatively, if allocation conditions and relative differences among commingled fluid PVT properties are such that the potential bias due to PVT is minimal or negligible (e.g. commingled black oils at low pressures and temperatures), then field measurements of $SF$ can be applied.
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**LABORATORY MEASUREMENT** (Laboratory shrinkage evaluation of a pressurized hydrocarbon liquid sample)

**SINGLE-STAGE FLASH**

\[
P_{\text{apc}} \quad T_{\text{apc}} \quad Q_{\text{apc}}
\]

**MULTISTAGE FLASH**

\[
P_{1,2,...n} \quad T_{1,2,...n} \quad Q_{1,2,...n}
\]

**EXPERIMENTAL THERMODYNAMIC EQUILIBRIUM POINTS (i.e., major liquid/vapor separation stages)**

For mass or moles:

\[Q_{\text{av}} = Q_{\text{apc}} \times VCF\]

For volume:

\[Q_{\text{av}} = Q_{\text{apc}} \times VCF\]

**CALCULATION** (Thermodynamic model, e.g., EOS shrinkage evaluation of hydrocarbon liquid)

**SINGLE-STAGE FLASH**

\[
P_{\text{apc}} \quad T_{\text{apc}} \quad Q_{\text{apc}}
\]

**MULTISTAGE FLASH**

\[
P_{1,2,...n} \quad T_{1,2,...n} \quad Q_{1,2,...n}
\]

**MODEL EQUILIBRIUM POINTS (i.e., major liquid/vapor separation stages)**

For mass or moles:

\[Q_{\text{av}} = Q_{\text{epc}} \times VCF\]

For volume:

\[Q_{\text{av}} = Q_{\text{epc}} \times VCF\]

**FIELD MEASUREMENT** (Field shrinkage evaluation of a pressurized hydrocarbon liquid sample, refer to Annex X)

**SINGLE-STAGE FLASH**

\[
P_{\text{apc}} \quad T_{\text{apc}} \quad Q_{\text{apc}}
\]

**NOTE 1**

For isothermal analysis, \(T_{\text{epc}} = T_{\text{apc}}\)

**NOTE 2**

For isothermal analysis, \(T_{\text{epc}} = T_{\text{apc}}\)

\[Q_{\text{av}} = Q_{\text{epc}} \times VCF\]

**VARIABLES**

- \(SF\): shrinkage factor \(SF = \frac{Q_{\text{svc}}}{Q_{\text{svc}}}\)
- \(Q_{\text{av}}\): quantity of liquid hydrocarbon at allocation point conditions
- \(Q_{\text{apc}}\): quantity of liquid hydrocarbon at atmospheric conditions
- \(Q_{\text{apc}}\): quantity of liquid hydrocarbon after field flash
- \(P_{\text{apc}}\): pressure of liquid hydrocarbon at allocation point conditions
- \(T_{\text{apc}}\): temperature of liquid hydrocarbon at allocation point conditions
- \(T_{\text{apc}}\): temperature of liquid hydrocarbon at field flash
- \(VCF\): volume correction factor

**NOTES**

- **NOTE 1**: For isothermal analysis, \(T_{\text{epc}} = T_{\text{apc}}\)
- **NOTE 2**: For isothermal analysis, \(T_{\text{epc}} = T_{\text{apc}}\)

**Figure 6 - Methods for oil shrinkage factor determination**

### 7.4.5.3 Gas Correction Factor, \(B_g\)

The gas correction factor, or \(B_g\), is the ratio of hydrocarbon gas quantity at allocation point conditions to the hydrocarbon gas quantity at standard conditions.

\(B_g\) shall be determined and applied to account for mass transfer of gas between the thermodynamic states represented by the allocation point and the end point, with end point quantities adjusted to standard conditions. For hydrocarbon gas, the final point of measurement and determination of allocation end quantities shall be the end point (e.g. sales meter). \(B_g\) shall be used to adjust PMAS input hydrocarbon gas quantities to standard conditions to match the reported allocation end quantities (e.g. sales gas energy determined from volume at standard conditions). To avoid bias in the PMAS, \(B_g\) determination among commingled allocation point fluids shall be consistently implemented and applied for each commingled fluid.

In general, \(B_g\) is determined by the following equation:

\[
B_g = \frac{Q_{g,apc}}{Q_{g,sc}}
\]

(4)
Where:

\( B_g \) is gas correction factor;
\( Q_{g,apc} \) is quantity of hydrocarbon gas at allocation point conditions;
\( Q_{g,sc} \) is quantity of hydrocarbon gas at standard conditions.

For a volume-based \( B_g \), the \( Q_{g,sc} \) is determined by the following equation:

\[
Q_{g,sc} = Q_{g,epc} \times \left( \frac{P_{g,epc}}{P_{sc}} \right) \times \left( \frac{T_{sc}}{T_{g,epc}} \right) \times \left( \frac{Z_{g,sc}}{Z_{g,epc}} \right)
\]

Where:

\( Q_{g,sc} \) is volume of hydrocarbon gas at standard conditions (mscf, \( 10^3 \) m\(^3\));
\( Q_{g,epc} \) is volume of hydrocarbon gas at end point conditions (mcf, \( 10^3 \) m\(^3\));
\( P_{g,epc} \) is pressure of hydrocarbon gas at end point conditions (psia, kPa);
\( P_{sc} \) is pressure at standard conditions (psia, kPa);
\( T_{sc} \) is temperature at standard conditions (°F, °C);
\( T_{g,epc} \) is temperature of hydrocarbon gas at end point conditions (°F, °C);
\( Z_{g,sc} \) is gas compressibility factor of hydrocarbon gas at standard conditions, determined with the gas composition at the end point (e.g., using AGA Report No. 8);
\( Z_{g,epc} \) is gas compressibility factor of hydrocarbon gas at end point conditions, determined with the gas composition at the end point (e.g., using AGA Report No. 8).

For a mass or molar-based \( B_g \), the quantity of gas at standard conditions, \( Q_{g,sc} \), is equal to the quantity of gas at end point conditions, \( Q_{g,epc} \), as it is assumed that no mass transfer of hydrocarbon has occurred (i.e. the conditions are thermodynamically equivalent).

\( B_g \) shall be determined from one the following methods:

- **Laboratory Measurement.** A sample of produced hydrocarbon gas at allocation point conditions is subject to transition in pressure and temperature to end point conditions. The \( B_g \) is determined as the ratio of measured hydrocarbon gas quantity at allocation point conditions (i.e. \( Q_{g,apc} \)) to the measured hydrocarbon gas quantity at end point conditions, adjusted to standard conditions (i.e. \( Q_{g,sc} \)). For volumetric \( B_g \) determination, the measured volume of hydrocarbon gas at end point conditions (i.e. \( Q_{g,epc} \)) is adjusted to standard conditions with gas compressibility factors determined with a gas composition corresponding to end point conditions (refer to eqn \( x \)). Mass or molar based measurements following phase conversion are reported at standard conditions.

  **NOTE** It is recognized that the gas composition at end point conditions will not equal the gas composition at standard conditions if additional phase conversion occurs after the end point. However, PMAS allocation is relative to end point conditions (i.e. allocation end quantity based on end point gas composition), thus the end point composition is utilized in determination of gas compressibility factors for end point and standard conditions.

\( B_g \) can be determined in a single-stage flash or under multistage flash conditions. Depending on the production process between the allocation point and the end point, a multistage flash can lead to a more accurate determination of \( B_g \). \( B_g \) is generally determined in the laboratory at the same time as the solution condensate-gas ratio, \( r_v \).

A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major liquid/vapor separation stages) between the allocation point and the end point.
• **Calculation.** A sample of produced hydrocarbon gas at allocation point conditions is subject to analysis to obtain the total hydrocarbon composition. Calculation of $B_g$ can proceed using defined correlations agreed among the affected parties or EOS modeling using the hydrocarbon gas composition and either a simulated single-stage or multistage flash calculation from allocation point conditions to end point conditions, adjusted to standard conditions. For volumetric $B_g$ determination, the calculated volume of hydrocarbon gas at end point conditions (i.e. $Q_{g,.epc}$) is adjusted to standard conditions with gas compressibility factors determined with a gas composition corresponding to end point conditions (refer to eqn x). Mass or molar based measurements following phase conversion are reported at standard conditions.

**NOTE** It is recognized that the gas composition at end point conditions will not equal the gas composition at standard conditions if additional phase conversion occurs after the end point. However, PMAS allocation is relative to end point conditions (i.e. allocation end quantity based on end point gas composition), thus the end point composition is utilized in determination of gas compressibility factors for end point and standard conditions.

A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major liquid/vapor separation stages) between the allocation point and the end point.

The EOS shall 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.

### 7.4.5.4 Water Correction Factor, $B_w$

The water correction factor, or $B_w$, is the ratio of water quantity at allocation point conditions to the water quantity at standard conditions.

$B_w$ shall be determined and applied to account for mass transfer between the thermodynamic states represented by the allocation point and the end point, with end point quantities adjusted to standard conditions. For water, the final point of liquid/vapor separation in the production process (e.g. a wet oil tank) prior to measurement and determination of allocation end quantities shall be the end point. $B_w$ shall be used to adjust PMAS input water quantities to standard conditions to match the reported allocation end quantities. To avoid bias in the PMAS, $B_w$ determination among commingled allocation point fluids shall be consistently implemented and applied for each commingled fluid.

**NOTE** Mass transfer associated with water moving between allocation point conditions and end point conditions is generally due to evolution of entrained hydrocarbon gas. Additionally, changes in water density between the end point conditions and standard conditions affect volumetric water determinations.

In general, $B_w$ is determined by the following equation:

$$B_w = \frac{Q_{w,apc}}{Q_{w,sc}}$$ (6)

Where:

- $B_w$ is water correction factor;
- $Q_{w,apc}$ is quantity of water at allocation point conditions;
- $Q_{w,sc}$ is quantity of water at standard conditions.

For a volume-based $B_w$, the $Q_{w,sc}$ is determined by the following equation:

$$Q_{w,sc} = Q_{w,epc} \times CTPL_w$$ (7)
Where:

\[ Q_{w,sc} \] is volume of water at standard conditions (bbl, m³);

\[ Q_{w,epc} \] is volume of water at end point conditions (bbl, m³);

\[ CTPL_{lw} \] is volume correction factor for the effect of temperature as addressed in Annex F, from end point conditions to standard conditions.

For a mass or molar-based \( B_w \), the quantity of water at standard conditions, \( Q_{w,sc} \), is equal to the quantity of water at end point conditions, \( Q_{w,epc} \), as it is assumed that no mass transfer has occurred (i.e. the conditions are thermodynamically equivalent).

\( B_w \) shall be determined from one the following methods:

- **Laboratory measurement.** A sample of produced water at allocation point conditions is subject to reduction in pressure and temperature to end point conditions. The \( B_w \) is determined as the ratio of measured water quantity at allocation point conditions (i.e. \( Q_{w,apc} \)) to the measured water quantity at end point conditions, adjusted to standard conditions (i.e. \( Q_{w,sc} \)). For volumetric \( B_w \) determination, measured volume of water at end point conditions (i.e. \( Q_{w,epc} \)) is adjusted to standard conditions using the method detailed in Annex F. Mass or molar based measurements following phase conversion are reported at standard conditions.

  NOTE Some laboratories might flash the sample to ambient conditions (in lieu of end point conditions, with an applied CTL\(_{lw}\) for volume \( B_w \) calculations). When agreed by affected parties, a laboratory determination of \( B_w \) directly to ambient conditions might be acceptable if it can be demonstrated that there is no bias introduced among the commingled allocation source quantities.

\( B_w \) can be determined in a single-stage flash or under multistage flash conditions. Depending on the production process between the allocation point and the end point, a multistage flash can lead to a more accurate determination of \( B_w \).

A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e., major liquid/vapor separation stages) between the allocation point and the end point.

- **Calculation.** A sample of produced water at allocation point conditions is subject to analysis to obtain the total composition. Calculation of \( B_w \) can proceed using defined correlations agreed among the affected parties. For volumetric \( B_w \) determination assuming negligible mass transfer and compressibility (i.e., pressure effects), the method detailed in Annex F can be used.

### 7.4.5.5 Flash Gas Factor, FF

The flash gas factor, or \( FF \) (also referred to as solution gas-oil ratio or gas-in-solution factor), is the ratio of evolved hydrocarbon gas quantity at standard conditions (evolved from hydrocarbon liquid as it is lowered in pressure and temperature from allocation point conditions to end point conditions) to the hydrocarbon liquid quantity at standard conditions.

\( FF \) shall be determined and applied to account for mass transfer associated with evolved hydrocarbon gas as hydrocarbon liquid transitions between the thermodynamic states represented by the allocation point and the end point, with end point quantities adjusted to standard conditions. For liquid hydrocarbons, the final point of liquid/vapor separation in the production process (e.g., a dry oil tank) prior to measurement and determination of allocation end quantities shall be the end point. \( FF \) shall be used to adjust PMAS input quantities to standard conditions to account for evolved hydrocarbon gas associated with an allocation point. To avoid bias in the PMAS, \( FF \) determination among commingled allocation point fluids shall be consistently implemented and applied for each commingled fluid.

In general, the \( FF \) is determined by the following equation:
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\[ FF = \frac{Q_{g,sc}}{Q_{o,sc}} \]  

(8)

Where:
- \( FF \) is flash gas factor;
- \( Q_{g,sc} \) is quantity of evolved hydrocarbon gas at standard conditions;
- \( Q_{o,sc} \) is quantity of liquid hydrocarbon at standard conditions.

For a volume-based \( FF \), \( Q_{g,sc} \) is determined from equation 5, and \( Q_{o,sc} \) is determined from equation 3.

For a mass or molar-based \( FF \), the quantity of hydrocarbon gas at standard conditions, \( Q_{g,sc} \), is equal to the quantity of hydrocarbon gas at end point conditions, \( Q_{g,epc} \), as it is assumed that no mass transfer of hydrocarbon has occurred (i.e. the conditions are thermodynamically equivalent). Likewise, \( Q_{o,sc} \) is equal to the quantity of oil at end point conditions, \( Q_{o,epc} \).

\( FF \) shall be determined from one of the following methods:

- **Laboratory measurement.** A sample of produced hydrocarbon liquid at allocation point conditions is subject to reduction in pressure and temperature to end point conditions. The \( FF \) is determined as the ratio of measured evolved hydrocarbon gas quantity at end point conditions, adjusted to standard conditions (i.e. \( Q_{g,sc} \)), to the measured hydrocarbon liquid quantity at end point conditions, adjusted to standard conditions (i.e. \( Q_{o,sc} \)). For volumetric \( FF \) determination, the measured volume of evolved hydrocarbon gas at end point conditions (i.e. \( Q_{g,epc} \)) is adjusted to standard conditions with gas compressibility factors determined with a gas composition corresponding to end point conditions (refer to eqn x). The measured volume of liquid hydrocarbon at end point conditions (i.e. \( Q_{o,epc} \)) is adjusted with volume correction factors (CPL and CTL as addressed in API MPMS Ch. 11.1) to standard conditions (refer to eqn x). Mass or molar based measurements following phase conversion are reported at standard conditions.

  **NOTE** Some laboratories might flash the sample to ambient conditions (in lieu of end point conditions). When agreed by affected parties, a laboratory determination of \( FF \) directly to ambient conditions might be acceptable if it can be demonstrated that there is no bias introduced among the commingled allocation source quantities.

\( FF \) can be determined in a single-stage flash or under multistage flash conditions. Depending on the production process between the allocation point and the end point, a multistage flash can lead to a more accurate determination of \( FF \). \( FF \) is generally determined in the laboratory at the same time as \( SF \).

A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major liquid/vapor separation stages) between the allocation point and the end point.

- **Calculation.** A sample of produced hydrocarbon liquid at allocation point conditions is subject to analysis to obtain the total hydrocarbon composition. EOS modeling using the hydrocarbon composition and either a simulated single-stage or multistage flash calculation from allocation point conditions to end point conditions, adjusted to standard conditions, can provide a calculated estimate of \( FF \). For volumetric \( FF \) determination, the calculated volume of evolved hydrocarbon gas at end point conditions (i.e. \( Q_{g,epc} \)) is adjusted to standard conditions with gas compressibility factors determined with a gas composition corresponding to end point conditions (refer to eqn x). The calculated volume of liquid hydrocarbon at end point conditions (i.e. \( Q_{o,epc} \)) is adjusted with volume correction factors (CPL and CTL as addressed in API MPMS Ch. 11.1) to standard conditions (refer to eqn x). Mass or molar based measurements following phase conversion are reported at standard conditions.
NOTE EOS modeling software packages can typically report results of the simulated flash calculation to end point conditions at standard conditions (i.e. the volume correction is addressed in the software).

NOTE EOS modeling might be used for flash calculations to ambient conditions (in lieu of end point conditions). When agreed by affected parties, an EOS determination of FF directly to ambient conditions might be acceptable if it can be demonstrated that there is no bias introduced among the commingled allocation source quantities.

A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major liquid/vapor separation stages) between the allocation point and the end point.

The EOS shall 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.

7.4.5.6 Solution Condensate-Gas Ratio, $r_s$

The solution condensate-gas ratio, or $r_s$ (also referred to as the vaporized CGR), is the ratio of condensed hydrocarbon liquid quantity at standard conditions (condensed from hydrocarbon gas as it is changed in pressure and temperature from allocation point conditions to end point conditions) to the hydrocarbon gas quantity at standard conditions.

$r_s$ shall be determined and applied to account for mass transfer associated with condensed hydrocarbon liquid as hydrocarbon gas transitions between the thermodynamic states represented by the allocation point and end point, with end point quantities adjusted to standard conditions. For hydrocarbon gas, the final point of measurement and determination of allocation end quantities shall be the end point (e.g. sales meter). For liquid hydrocarbons, the final point of liquid/vapor separation in the production process (e.g. a dry oil tank) prior to measurement and determination of allocation end quantities shall be the end point. $r_s$ shall be used to adjust PMAS input quantities to standard conditions to account for condensed hydrocarbon liquid associated with an allocation point. To avoid bias in the PMAS, $r_s$ determination among commingled allocation point fluids shall be consistently implemented and applied for each commingled field.

In general, the $r_s$ is determined by the following equation:

$$r_s = \frac{Q_{o,sc}}{Q_{g,sc}}$$

(9)

Where:

- $r_s$ is solution condensate-gas ratio;
- $Q_{o,sc}$ is quantity of condensed liquid hydrocarbon at standard conditions;
- $Q_{g,sc}$ is quantity of hydrocarbon gas at standard conditions.

NOTE In determination of $r_s$, it is recognized that the hydrocarbon gas and liquid are evaluated via two different thermodynamic paths. The hydrocarbon gas quantity is evaluated from allocation point conditions to end point conditions (i.e., end point conditions for the hydrocarbon gas, e.g. sales), then adjusted to standard conditions. The hydrocarbon liquid quantity that is condensed from the hydrocarbon gas transitioning from allocation point conditions to gas end point conditions is then separately evaluated from gas end point conditions to hydrocarbon liquid end point conditions (i.e., end point conditions of the hydrocarbon liquid, e.g. dry oil tank), then adjusted to standard conditions. Refer to figure x for a diagram depiction of the process.

For a volume-based $r_s$, the $Q_{o,sc}$ is determined by eqn x and the $Q_{g,sc}$ is determined by eqn x.

For a mass or molar-based $r_s$, the quantity of hydrocarbon gas at standard conditions, $Q_{g,sc}$ is equal to the quantity of hydrocarbon gas at end point conditions, $Q_{g.epc}$, as it is assumed that no mass transfer of hydrocarbon has occurred (i.e., the conditions are thermodynamically equivalent). Likewise, $Q_{o,sc}$ is equal to the quantity of oil at end point conditions, $Q_{o.epc}$.
$r_s$ shall be determined by the following methods:

- **Calculation.** A sample of produced hydrocarbon gas at allocation point conditions is subject to analysis to obtain the total hydrocarbon composition. Calculation of $r_s$ can proceed using defined correlations agreed among the affected parties or EOS modeling using the hydrocarbon gas composition and either a simulated single-stage or multistage flash calculations from allocation point conditions to the gas and liquid end point conditions, adjusted to standard conditions (refer to the 'Laboratory Measurement' bullet for a description of thermodynamic process). For volumetric $r_s$ determination, the measured volume of liquid hydrocarbon at end point conditions (i.e. $Q_{lepc}$) is adjusted with volume correction factors (CPL and CTL as addressed in API MPMS Ch. 11.1) to standard conditions (refer to eqn x). The measured volume of hydrocarbon gas at end point conditions (i.e. $Q_{gepc}$) is adjusted to standard conditions with gas compressibility factors determined with a gas composition corresponding to end point conditions (refer to eqn x). Mass or molar based measurements following phase conversion are reported at standard conditions.

NOTE It is recognized that the gas composition at end point conditions will not equal the gas composition at standard conditions if additional phase conversion occurs after the end point. However, PMAS allocation is relative to end point conditions (i.e. allocation end quantity based on end point gas composition), thus the end point composition is utilized in determination of gas compressibility factors for end point and standard conditions.

A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major liquid/vapor separation stages) between the allocation point and the end points.

The EOS shall 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.

### 7.5 Procedures and Formulations for the Determination of Net Theoretical Quantities

#### 7.5.1 General

Net theoretical quantities are allocation source quantities adjusted to standard conditions, net of associated circulated, consumed and accumulated quantities. Net theoretical quantities shall be determined for each allocation source quantity prior to use in the allocation method, with assumptions and calculations documented for each theoretical quantity determination.

#### 7.5.2 Procedure and Formulation to Determine Net Theoretical Oil Quantity of an Allocation Source

**7.5.2.1 Net Theoretical Oil Quantity of an Allocation Source**

A procedure shall be developed to determine allocation source net theoretical oil quantity at standard conditions ($NTOQ_{source,sc}$) accounting for circulated oil, oil inventory adjustments, and other oil quantity adjustments of consequence to the allocation.

The general equation for calculating allocation source net theoretical oil quantity at standard conditions for the allocation period is the following:

$$NTOQ_{source,sc} = GTOQ_{source,sc} - COQ_{source,sc} + \Delta InvQ_{source,sc} + AdQ_{source,sc}$$  \(10\)
7.5.2.2 Gross Theoretical Oil Quantity of an Allocation Source

7.5.2.2.1 General

A procedure shall be developed to determine allocation source gross theoretical oil quantity \( GTOQ_{source,sc} \) that includes correction for water, adjustment for phase change between allocation point conditions and standard conditions, and inclusion of hydrocarbon liquid condensed from the allocation source gas. The procedure can use PVT factors applied to measured or calculated quantities, phase conversion models, or a combination of both to determine the gross theoretical oil quantity.

The general equation for calculating allocation source gross theoretical oil quantity at standard conditions for the allocation period is the following:

\[
GTOQ_{source,sc} = LQ_{source,apc} \times (1 - X_{w,apc}) \times SF_{source} + GQ_{source,apc} \times \frac{1}{B_{g,source}} \times r_{s,source} \tag{11}
\]

Where:

- \( GTOQ_{source,sc} \) is gross theoretical oil quantity of an allocation source (determined from measurement or calculation applicable to the allocation point), at standard conditions.
- \( LQ_{source,apc} \) is measured or calculated liquid quantity of an allocation source at allocation point conditions.
- \( X_{w,apc} \) is quantity fraction of water in the allocation source liquid adjusted to allocation point conditions (refer to eqn x).
- \( SF_{source} \) is shrinkage factor of an allocation source liquid hydrocarbon accounting for phase change from allocation point conditions to end point conditions, adjusted to standard conditions (refer to Section 7.4.5.2).
- \( GQ_{source,apc} \) is measured or calculated gas quantity of an allocation source at allocation point conditions.
- \( B_{g,source} \) is gas correction factor of an allocation source gas accounting for phase change from allocation point conditions to end point conditions, adjusted to standard conditions (refer to Section 7.4.5.3).
$r_{s,source}$ is solution condensate-gas ratio of an allocation source gas accounting for phase change from allocation point conditions to end point conditions, adjusted to standard conditions (refer to Section 7.4.5.6).

NOTE Volume-based quantities are generally bbls (m³), mass-based quantities are generally lbm (kg), and mole-based quantities are moles.

### 7.5.2.2.2 Quantity Fraction of Water in the Allocation Source Liquid

A procedure shall be developed to determine allocation source quantity fraction of water at allocation point conditions ($X_{w,apc}$) when the allocation source quantity is composed of hydrocarbon liquid and water. Quantity fraction of water may be obtained from an online water determination device or through manual or automatic sampling with subsequent analysis.

For collected allocation source liquid samples evaluated at atmospheric pressure and sample temperature, the general equation for calculating allocation source quantity fraction of water at allocation point conditions for the allocation period is the following:

$$X_{w,apc} = \frac{X_{w,sc}x_{w,source}}{X_{w,sc}x_{w,source} + (1 - X_{w,sc})x_{SF,source}}$$

(12)

Where:

- $X_{w,apc}$ is quantity fraction of water in the allocation source liquid adjusted to allocation point conditions.
- $X_{w,sc}$ is quantity fraction of water in a sample of allocation source liquid, evaluated at atmospheric pressure and sample temperature, adjusted to standard conditions (refer to Annex F for adjustment to standard conditions of volume-based quantities).
- $B_{source}$ is water correction factor of an allocation source water accounting from allocation point conditions to end point conditions, adjusted to standard conditions (refer to Section 7.4.5.4).
- $SF_{source}$ is shrinkage factor of an allocation source liquid hydrocarbon accounting for phase change from allocation point conditions to end point conditions, adjusted to standard conditions (refer to Section 7.4.5.2).

NOTE Mass fraction of water is not impacted by pressure or temperature change.

NOTE When agreed by affected parties, correction for the salinity of water (i.e. use of Annex F) can be avoided if it can be demonstrated that there is no bias introduced among the commingled allocation source quantities.

### 7.5.2.3 Circulated Oil Quantity Associated with an Allocation Source

Stabilized circulated oil quantities shall be subtracted from the gross theoretical oil quantity of the source receiving the circulated oil.

Circulated oil is hydrocarbon liquid removed from the process upstream of an allocation tier endpoint and introduced back into the process upstream of a tier source. In this situation, the circulated oil is commingled with a produced hydrocarbon stream and measured at the source measurement point. Circulated oil is most often stabilized oil. Because the circulated oil was measured initially as production, the circulated quantity shall not be counted again as production.

When circulated oil is commingled with a produced stream, the composition of the stream changes. This compositional change impacts liquid density and shrinkage. Quantities, shrinkage factors, flash gas
factors, flash gas energy content, densities, compositional analyses and other compositionally sensitive properties used as input to the allocation shall be representative of the liquid from the commingled stream. This applies to both stable and non-stable circulated oil. When such properties are not available, procedures shall be developed to determine the adjustment to the extent necessary to render system bias inconsequential.

When oil is drawn from a point outside of the allocation tier boundaries, and introduced downstream of an allocation tier source, the source inputs shall be adjusted to represent the commingled stream. When this outside stream is introduced downstream of the allocation sources, it shall be considered a PMAS source. Circulated oil removed from the process upstream of an allocation tier endpoint and introduced back into the process downstream of the sources of the same tier should be considered part of the overall hydrocarbon process with no impact to theoretical quantities other than through normal hydrocarbon processing.

7.5.2.4 Inventory Oil Quantity Associated with an Allocation Source

Production systems with oil storage capabilities and a significant difference in production and export quantities within an allocation period and fluctuating storage quantities between allocation periods shall include an inventory procedure in the PMAS.

A PMAS inventory shall have a facility inventory representing the total inventory participating in the PMAS. The facility inventory shall be divided into source specific inventories for each PMAS source unless a particular source is identified as a non-participant in the inventory. For each allocation period, each participating source shall have a beginning inventory and ending inventory. The inventory quantities shall be at standard conditions. The beginning source inventory for an allocation period is the ending source inventory from the previous period. Changes in inventory shall be addressed using one of two methods.

The first method uses a First In First Out (FIFO) process where the source theoretical volumes are adjusted proportionally to sales volume plus the change in total inventory. The adjusted source theoretical volume plus the change in inventory becomes the allocated source volume. An example of this method is found in Annex D – Tank Inventory Calculations.

The second method uses an Available to Sales process where the source theoretical volumes are adjusted proportionally to sales volume plus the change in inventory. The adjusted source theoretical volume plus the source opening inventory represents the source volume available for sales. The sales volume is allocated on a proportional basis to these volumes. An example of this method is found in Annex D – Tank Inventory Calculations.

When a PMAS includes an inventory, prior period adjustments that impact that allocation period source inventories, the operator shall adjust each subsequent period allocation to correct the source inventories or make a one time documented correction, agreeable to all affected parties, to correct the source inventories.

7.5.2.5 Additional Oil Quantity Associated with an Allocation Source

Oil quantities attributable to a source, not already accounted for in the gross theoretical oil quantity, circulated oil quantity or inventory adjustment, shall be added to net theoretical oil quantity when the attributable quantity contributes to the export oil quantity. Oil quantities attributable to a source included in the source gross theoretical oil quantity, circulated oil quantity or inventory adjustment, shall be subtracted from the net theoretical oil quantity when the attributable quantity does not contribute to the export oil quantity.

Examples of additional oil quantity adjustments include line-fill not considered inventory, line blowdown for maintenance and repair, line abandonment, and non-standard operations associated with an upset.
When adjustment oil is commingled with a produced stream, the composition of the stream may change. This compositional change impacts liquid density and shrinkage. Quantities, shrinkage factors, flash gas factors, flash gas energy content, densities, compositional analyses and other compositionally sensitive properties used as input to the allocation shall be representative of the liquid from the commingled stream. This applies to both stable and non-stable adjustment oil. When such properties are not available, procedures shall be developed to determine the adjustment to the extent necessary to render system bias inconsequential.

7.5.3 Procedure and Formulation to Determine Net Theoretical Gas Quantity of an Allocation Source

7.5.3.1 Net Theoretical Gas Quantity of an Allocation Source

A procedure shall be developed to determine allocation source net theoretical gas quantity at standard conditions \( (NTGQ_{source,sc}) \) accounting for flash gas, fuel gas, flare gas, circulated gas, and other quantity adjustments of consequence to the allocation.

The general equation for calculating allocation source net theoretical gas quantity at standard conditions for the allocation period is the following:

\[
NTGQ_{source,sc} = GTGQ_{source,sc} + FlshG_{source,sc} - FlGQ_{source,sc} - FuGQ_{source,sc} - CGQ_{source,sc} + AdQ_{source,sc}
\]  (13)

Where:

- \( NTGQ_{source,sc} \) is net theoretical gas quantity of an allocation source, at standard conditions.
- \( GTGQ_{source,sc} \) is gross theoretical gas quantity of an allocation source (determined from measurement or calculation applicable to the allocation point), at standard conditions.
- \( FlshG_{source,sc} \) is flash gas quantity of an allocation source at standard conditions.
- \( FuGQ_{source,sc} \) is fuel gas quantity associated with an allocation source at standard conditions.
- \( FlQ_{source,sc} \) is flare gas quantity associated with an allocation source at standard conditions.
- \( CGQ_{source,sc} \) is circulated gas quantity associated with an allocation source at standard conditions.
- \( AdQ_{source,sc} \) is additional gas quantity adjustments associated with an allocation source, at standard conditions.

Note: Volume-based quantities are generally mscf \((10^3 \text{ m}^3)\), mass-based quantities are generally lbm \((\text{kg})\), and mole-based quantities are moles.

7.5.3.2 Gross Theoretical Gas Quantity of an Allocation Source

7.5.3.2.1 General

For a PMAS, separator gas measurement or calculation shall be an indicated volume at meter conditions (EQ 13). Production gas will experience volumetric, mass and molar change and phase conversion, necessitating the determination and use of a shrinkage factor applied to the indicated volume at meter conditions. Refer to Section 7.5.6 for volume and mass loss through condensation.

If it is determined that downstream phase conversion does not materially impact the allocation and affected parties agree, standard conditions may be used (EQ 14).

The equations to determine gross theoretical gas quantity are:
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\[
GTGQ_{sc, source} = GQ_{mcs, source} \times (1 - X_{wg, mc, source}) \times \frac{1}{B_{g, source}}
\]

(14)

Note: When the source quantity is mass or molar, the change in quantity is impacted by phase change only.

\[
GTGQ_{sc, source} = GQ_{sc, source} \times (1 - X_{wg, sc, source})
\]

(15)

Note: When the source quantity is not impacted by phase change.

Where:

- \(GTGQ_{sc, source}\) Theoretical Gas Quantity at standard conditions (mscf, 10^3 m^3).
- \(GQ_{mcs, source}\) Measured or Calculated Gas Quantity at measured conditions (macf, 10^3 m^3).
- \(GQ_{sc, source}\) Measured or Calculated Gas Quantity at standard conditions (mscf, 10^3 m^3).
- \(X_{wg, mc, source}\) Fraction of water in the gas adjusted to metered conditions. For volume allocation, this shall mean the volume fraction. For mass allocation, this shall mean the mass fraction.
- \(X_{wg, sc, source}\) Fraction of water in the gas adjusted to standard conditions. For volume allocation, this shall mean the volume fraction. For mass allocation, this shall mean the mass fraction.
- \(B_{g, source}\) Gas volume correction factor for a source to account for phase change, pressure and temperature effects on source quantities (measured conditions/ standard conditions) (macf/mscf, 10^3 m^3/10^3 m^3)

**NOTE** Volume-based quantities are generally mscf (10^3 m^3), mass-based quantities are generally lbm (kg), and mole-based quantities are moles

### 7.5.3.2.2 Correction for Water

A gas quantity that has been in contact with water will include water vapor. The water vapor in the gas is typically removed in gas processing prior to export. The quantity of measured gas for each source shall be corrected to remove the gas quantity attributable to water vapor. If volumes are adjusted for water vapor, then energy content shall be on a dry basis.

There are several methods available to determine the water fraction of a gas quantity. One method includes lab analysis. Another method that can be used is the determination of the water vapor volume by vapor pressure.

Assume the vapor pressure of the water at measured conditions relative to the total gas pressure is the partial pressure of the water vapor at the separation point. The partial pressure of the water vapor is equal to partial volume of the water vapor. The vapor pressure can be determined using a basic vapor pressure equation such as Antoine’s equation. Typically, the water vapor pressure relative to the total pressure is directly proportional to the water vapor volume to the total volume. This ratio can be applied to determine water fraction.

\[
X_{wg} = 1 - \left(\frac{P_{water \ vapor}}{P_{total}}\right)
\]

(16)

Where:

- \(P_{water \ vapor}\) Vapor pressure of water at gas measurement conditions (psia, kPa)
- \(P_{total}\) Pressure of the gas measurement conditions (psia, kPa)
Although the water vapor pressure relative to the total pressure is directly proportional to the water vapor volume to the total volume, the mass ratio does not follow this rule. The gas and water vapor mass has to be determined from the volumes first then the mass ratio can be determined.

A more rigorous approach may be required when the observed temperatures of source quantities differ significantly, greater than 50 °F.

The mole fraction of water can be removed from the total moles when the gas quantity input into the allocation is molar mass or molar volume.

Water vapor quantities in a gas stream can also be determined using a process simulator.

### 7.5.3.2.3 Compressibility Factor

If the allocation basis is an ideal gas, a compressibility factor is required to convert a real gas volume measurement to an ideal gas volume. The \( Z \) factor or compressibility factor is the ratio of the molar volume of a real gas to the molar volume of the ideal gas at the same pressure and temperature. Note that compressibility is a function of pressure and temperature. A \( Z \) factor shall be applied when the input gas volume is not consistent with the allocation basis in terms of real or ideal gas. The \( Z \) factor can be obtained from generalized compressibility charts for specific gases or calculated using an equation of state.

\[
Q_{i,g} = \frac{Q_{r,g}}{Z}
\]  

Where:

- \( Q_{i,g} \) Volume of ideal gas (mscf, \( 10^3 \text{m}^3 \))
- \( Q_{r,g} \) Volume of real gas (mscf, \( 10^3 \text{m}^3 \))
- \( Z \) Compressibility factor

When converting a real gas volume to a gas mass, a real gas density shall be used. When converting an ideal gas volume to a gas mass, an ideal gas density shall be used.

The mass of the gas is unaffected by compressibility.

NOTE: Process modelling tools may require inputs in ideal gas.

### 7.5.3.3 Flash Gas Associated with an Allocation Source

The flash gas quantity of a liquid source shall be determined in the PMAS. A flash gas factor applied to the processes hydrocarbon liquid quantity may be used to determine the flash gas quantity.

\[
FlshQ_{source,sc} = GTOQ_{sc,source} \times FF_{source}
\]  

Where:

- \( FlshQ_{source,sc} \) Flash gas quantity at standard conditions.
- \( GTOQ_{sc,source} \) is gross theoretical gas quantity of an allocation source (determined from measurement or calculation applicable to the allocation point), at standard conditions.
- \( FF_{source} \) is flash gas factor of an allocation source liquid hydrocarbon accounting for phase change from allocation point conditions to end point conditions, adjusted to standard conditions (refer to Section 7.4.5.5).

NOTE Volume-based quantities are generally mscf \( (10^3 \text{ m}^3) \), mass-based quantities are generally lbm (kg), and mole-based quantities are moles
This factor may be provided by a laboratory and is generally in terms of \((\text{standard gas volume})/(\text{standard liquid volume})\). The standard liquid volume is the resulting gross theoretical liquid volume of a source. When using a flash gas factor, ensure that the factor is applied to the appropriate liquid volume. Mass and molar based PMAS shall use flash gas factors based on mass or moles. Flash gas may also be determined using a process simulator.

Flash gas is the gas that evolves from non-stable hydrocarbon liquid as it is processed to a stable liquid. The flash gas is liberated from the liquid at points of separation within the process. These separation points include separators, degassers, treaters, stabilizers, and tanks. The flash gas streams become laden with heavier hydrocarbon molecules as the process pressure drops or temperature rises. In processes with multiple points of separation, the flash gas streams are not compositionally the same.

Unlike primary gas, flash gas is not metered for individual sources. Flash gas for combined streams is often measured. These measurement points may act as sources in a multi-tier PMAS or may be used to validate flash gas quantities independently determined. When the flash gas measurement point acts as a source in an allocation tier, Section 7 shall apply.

The energy content of the flash gas stream can also be obtained from a laboratory and is generally in terms of energy/(unit volume). In an energy based allocation, the flash gas energy can be determined by applying the energy content to the gas quantity determined by the flash gas factor.

Flash gas factor and energy content are typically determined in the same analysis to determine the liquid shrinkage factor, a single stage flash of the hydrocarbon liquid. Just as the liquid shrink factor is impacted by the conditions under which the liquid sample is analyzed, so too are the flash gas factor and energy content. A multi-stage flash representing the process is a more rigorous approach to determining these factors. However, the effects on the hydrocarbon streams from the commingling are not captured when the hydrocarbon is analyzed independently of the other streams. A PMAS using a phase behavior model can capture the impacts associated with commingling.

The flash gas volume may be assigned to a gas source associated with the liquid source, to source liquid stream as a separate product (as a liquid equivalent) stream, or as separate allocation source stream.

7.5.3.4 Flare Gas Associated with an Allocation Source

A flare gas assignment procedure shall be included in the PMAS to distribute the consumed flare gas to sources.

Flare gas quantities shall be assigned to sources on a throughput basis except when a flare event can be attributed to a particular source or sources. In this situation, the event quantity is subtracted from the total flare quantity for the allocation period and assigned directly to the source or sources. The remaining flare quantity is assigned on a throughput basis.

Flare gas is gas drawn from the process, consumed, and not available for export. Flare gas is metered or quantified and can originate from multiple points within the process. Flare gas may include other consumed gas not otherwise assigned.

In an energy based PMAS, the energy of the total flare quantity and event flare quantities shall be determined.

7.5.3.5 Fuel Gas Associated with an Allocation Source

A fuel gas assignment procedure shall be included in the PMAS to distribute the consumed fuel gas to sources. Consumed gas not measured by fuel meters such as blanket gas and flare pilots shall not be considered fuel gas unless they too are metered or quantified and the meter is deemed a fuel meter for allocation purposes.
In process systems with dissimilar fluids, sources introduced at different process points, or sources processed at different temperature/pressure conditions, the fuel consumed for the work load shall be assigned to sources based on a theoretical energy consumed by the individual source.

When the gas is drawn upstream of gas drying, the measured fuel quantity shall be corrected for water vapor.

When there are fuel consumers with different fuel sources or when the allocation is energy based, the energy content of the fuel source shall be determined and the fuel gas energy shall be the basis for fuel gas assignment.

In a PMAS with similar fluids and similar process conditions, fuel gas may be assigned to sources based on production throughput. Throughput may include oil quantities, gas quantities, energy quantities, water quantities, and oil quantity equivalents.

Fuel gas is gas drawn from the process and consumed to support the process directly as fuel for compressors, pumps, electric generators, and process heaters (work load) and indirectly as fuel for electric generators to provide power for lighting, HVAC, and ancillary equipment (common load). When fuel is assigned by consumption, the assignment basis may be process simulation output, energy calculations, measured electrical energy consumed by equipment or a combination of the three. The assigned quantity may be a function of the work load or total fuel consumption. When the work load is assigned by consumption, the remainder of the fuel consumption shall be deemed common load and assigned on a throughput basis to the allocation sources.

When gas from outside the process is used for fuel, that gas stream shall be considered an allocation source or addressed outside the allocation process by some other commercial means.

NOTE: Fuel gas may be allocated on a throughput basis if agreed to by all parties.

7.5.3.6 Circulated Gas Associated with an Allocation Source

Circulated gas quantities shall be subtracted from the gross theoretical gas quantity of the source receiving the circulated gas.

The measured circulated gas quantity shall not be corrected for water vapor if it is drawn from the process downstream of gas drying.

Circulated gas is hydrocarbon gas removed from the process upstream of an allocation tier endpoint and introduced back into the process upstream of a tier source. In this situation, the circulated gas is commingled with a produced hydrocarbon stream and measured at the source measurement point. Circulated gas is most often dry sales gas. Because the circulated gas was measured initially as production, the circulated quantity shall not be counted again as production.

NOTE: A common example of circulated gas is gas lifting of wells

When circulated gas is commingled with a produced stream, the composition of the stream changes. Quantities, energy content, densities, compositional analyses and other compositionally sensitive properties used as input to the allocation shall be representative of the commingled stream. When such properties are not available, procedures shall be developed to determine the adjustment to the extent necessary to render system bias inconsequential.

When gas is drawn from a point outside of the allocation tier boundaries and introduced upstream of an existing source, the allocation inputs shall be adjusted to reflect the commingled stream. When this outside source is introduced downstream of the sources, it shall be considered an allocation source.

Circulated gas removed from the process upstream of an allocation tier endpoint and introduced back into the process downstream of the sources of the same tier should be considered part of the overall hydrocarbon process with no impact to theoretical quantities other than through normal hydrocarbon processing.
7.5.3.7  Additional Gas Quantity Associated with an Allocation Source

Gas quantities attributable to a source, not already accounted for in the gross theoretical gas quantity, flash, fuel, flare, or circulated gas quantities, shall be added to net theoretical gas quantity when the attributable quantity contributes to the export gas quantity. Gas quantities attributable to a source included in the source gross theoretical gas quantity, flash, fuel, flare, or circulated gas quantities, shall be subtracted from the net theoretical oil quantity when the attributable quantity does not contribute to the export gas quantity.

Examples of additional gas quantity adjustments include line-fill, line blowdown for maintenance and repair, line abandonment, and non-standard operations associated with an upset. Adjusted gas quantity may also be used to account for the gas volume change due to fluctuations in pressure in large gathering systems.

When adjustment gas is commingled with a produced stream, the composition of the stream may change. Quantities, energy content, densities, compositional analyses and other compositionally sensitive properties used as input to the allocation shall be representative of the liquid from the commingled stream. When such properties are not available, procedures shall be developed to determine the adjustment to the extent necessary to render system bias inconsequential.

7.5.3.8  Vent Gas

Vent gas is gas drawn from the process, consumed or lost, and not available for export. Vent gas is quantified and can originate from multiple points within the process. Two commons points are storage tank vents and glycol regeneration units.

Vent gas quantities are quite small relative to produced gas quantities. Assignment of vent gas quantities in an allocation process will generally add complexity to the system without impact to the allocation outcome. If agreed upon, vent gas quantification and assignment to meet regulatory requirements should be done outside of the PMAS.

When vent gas is included in the PMAS, vent points shall be identified and algorithms shall be identified or developed to quantify vent gas to be assigned back to the sources.

7.5.4  Procedure to Correct Molar Quantities for Process Losses

Molar quantities can be determined when the composition is known at a volume or mass measurement point. The change in molar quantity from one process point to the next can be determined using the ratio of the process input to process output quantity of each component. The input molar quantity is determined by summing the source molar quantities for each component. The output molar quantity is determined by quantity measurement and composition or by process simulation. The resultant ratio is applied to each component of each source. The total quantity for each source at output point is the sum of the component quantities.
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Figure 7 – Determination of Molar Volume or Mass Change from One Process Point to Another

\[
\begin{align*}
Q_A &= \Sigma Cn_A \\
Q_B &= \Sigma Cn_B \\
Q_C &= \Sigma Cn_C \\
Q_{IN} &= \Sigma Cn_{IN} \\
Q_{OUT} &= \Sigma Cn_{OUT}
\end{align*}
\]

\[
\begin{align*}
C_{n_{IN}} &= Cn_A + Cn_B + \ldots + Cn_N \\
C_{n_{A,OUT}} &= Cn_A \times \frac{Cn_{OUT}}{Cn_{IN}}; \\
C_{n_{B,OUT}} &= Cn_B \times \frac{Cn_{OUT}}{Cn_{IN}}; \\
C_{n_{C,OUT}} &= Cn_C \times \frac{Cn_{OUT}}{Cn_{IN}} \\
Q_{A,OUT} &= \Sigma Cn_{A,OUT}; \\
Q_{B,OUT} &= \Sigma Cn_{B,OUT}; \\
Q_{C,OUT} &= \Sigma Cn_{C,OUT}
\end{align*}
\]

Where:
- \(Q\) Volume/Mass quantity
- \(C_1, C_2 \ldots C_n\) components of quantity \(Q\).

When converting a volume to a molar volume or molar mass, note that component liquid densities and volumes are ideal while measured volumes are real liquids. This difference shall be addressed when using these conversions in an allocation procedure. The difference can be addressed by using a phase behavior simulation or by determining that the difference is not impactful to achieving equitable and acceptable results. Pseudo-components are often stream specific and should not be interchanged unless they have the same thermodynamic properties.

7.5.5 Procedure and Formulation to Determine Net Theoretical Water Quantity of an Allocation Source

7.5.5.1 Net Theoretical Water Quantity of an Allocation Source

A procedure shall be developed to determine allocation source net theoretical water quantity at standard conditions \((NTW(Q_{source,sc}))\) accounting for circulated water, water inventory adjustments, and other water quantity adjustments of consequence to the allocation.
The general equation for calculating allocation source net theoretical water quantity at standard conditions for the allocation period is the following:

\[
NTWQ_{source,sc} = GTWQ_{source,sc} - CWQ_{source,sc} + \Delta invWQ_{source,sc} + AdWQ_{source,sc}
\]  
(22)

Where:

- \(NTWQ_{source,sc}\) is net theoretical water quantity of an allocation source, at standard conditions.
- \(GTWQ_{source,sc}\) is gross theoretical water quantity of an allocation source (determined from measurement or calculation applicable to the allocation point), at standard conditions.
- \(CWQ_{source,sc}\) is circulated water quantity associated with an allocation source, at standard conditions.
- \(\Delta invWQ_{source,sc}\) is change in inventory water quantity associated with an allocation source, at standard conditions.
- \(AdWQ_{source,sc}\) is additional water quantity adjustments associated with an allocation source, at standard conditions.

**NOTE** Volume-based quantities are generally bbls (m³), mass-based quantities are generally lbm (kg), and mole-based quantities are moles.

### 7.5.5.2 Gross Theoretical Water Quantity of an Allocation Source

A procedure shall be developed to determine allocation source gross theoretical water quantity \((GTWQ_{source,sc})\) that includes correction for water, adjustment for phase change between allocation point conditions and standard conditions, and inclusion of water in hydrocarbon liquid associated with the allocation source. The procedure can use PVT factors applied to measured or calculated quantities, phase conversion models, or a combination of both to determine the gross theoretical oil quantity.

The general equation for calculating allocation source gross theoretical water quantity at standard conditions for the allocation period is the following:

\[
GTWQ_{source,sc} = WQ_{source,apc} \times \frac{1}{B_w,source}
\]  
(23)

Where:

- \(GTWQ_{source,sc}\) is gross theoretical water quantity of an allocation source (determined from measurement or calculation applicable to the allocation point), at standard conditions.
- \(WQ_{source,apc}\) is measured or calculated water quantity of an allocation source at allocation point conditions.
- \(B_w,source\) is water correction factor of an allocation source water accounting for phase change from allocation point conditions to end point conditions, adjusted to standard conditions (refer to Section 7.4.5.4).

**NOTE** Volume-based quantities are generally bbls (m³), mass-based quantities are generally lbm (kg), and mole-based quantities are moles.

**NOTE:** There are two methodologies to determine oil volume produced over an allocation period when inline water cut analyser and a total liquid meter are used in liquid outlet of a two-phase separator, or the oil outlet of a three-phase separator. These methods are:

1. Use of average values of total liquid flow and water cut over and allocation period
2. Discrete integration of total liquid flow and water cut
The use of an inline water cut analyser typically involves a flow computation device that allows the continuous accumulation of produced oil volume based on the instantaneous total liquid flow (water and oil) and the water cut reading from the analyser. This method would yield more accurate results particularly in conditions where the source wells have different water production rates, and where well alignment changes over an allocation period.

7.5.5.3 Circulated Water Quantity Associated with an Allocation Source

For a PMAS that includes a water allocation, circulated water quantities shall be subtracted from the gross theoretical water quantity of the source receiving the circulated water. In a water volume based PMAS, the circulated water volume shall be adjusted to theoretical water volume conditions.

Circulated water is water removed from the process upstream of an allocation tier endpoint and introduced back into the process upstream of a tier source. In this situation, the circulated water is commingled with a produced hydrocarbon/water stream and measured at the source measurement point. Circulated water is most often produced. Because the circulated water was measured initially as production, the circulated quantity shall not be counted again as production.

When water is drawn from a point outside of the allocation tier boundaries, and introduced downstream of an allocation tier source, the source inputs shall be adjusted to represent the commingled stream. When this outside stream is introduced downstream of the allocation sources, it shall be considered a PMAS source.

Circulated water removed from the process upstream of an allocation tier endpoint and introduced back into the process downstream of the sources of the same tier should be considered part of the overall process with no impact to theoretical quantities other than through normal processing.

7.5.5.4 Inventory Water Quantity Associated with an Allocation Source

When the PMAS includes a water allocation and the production system has water storage capabilities and a significant difference in production and export quantities within an allocation period and fluctuating storage quantities between allocation periods, the PMAS shall include a water inventory procedure.

A PMAS water inventory shall have a facility inventory representing the total inventory participating in the PMAS. The facility water inventory shall be divided into source specific inventories for each PMAS source unless a particular source is identified as a non-participant in the inventory. For each allocation period, each participating source shall have a beginning inventory and ending inventory. The inventory quantities shall be at standard conditions. The beginning source inventory for an allocation period is the ending source inventory from the previous period. Changes in inventory shall be addressed using one of two methods.

The first method uses a First In First Out (FIFO) process where the source theoretical volumes are adjusted proportionally to export volume plus the change in total inventory. The adjusted source theoretical volume plus the change in inventory becomes the allocated source volume. An example of this method is found in Annex D.

The second method uses an Available to Export process where the source theoretical volumes are adjusted proportionally to export volume plus the change in inventory. The adjusted source theoretical volume plus the source opening inventory represents the source volume available for export. The export volume is allocated on a proportional basis to these volumes. An example of this method is found in Annex D.

When a PMAS includes an inventory, prior period adjustments that impact that allocation period source inventories, the operator shall adjust each subsequent period allocation to correct the source inventories or make a one time documented correction, agreeable to all affected parties, to correct the source inventories.
7.5.5.5 Additional Water Quantity Associated with an Allocation Source

For a PMAS containing a water allocation, water quantities attributable to a source, not already accounted for in the gross theoretical water quantity, circulated quantity, or water inventory adjustment, shall be added to net theoretical water quantity when the attributable quantity contributes to the export water quantity. Water quantities attributable to a source included in the source gross theoretical water quantity, circulated water quantity or water inventory adjustment, shall be subtracted from the net theoretical water quantity when the attributable quantity does not contribute to the export water quantity. In a volume based PMAS, the water adjustment volume shall be adjusted to theoretical water volume conditions.

7.6 Allocation Method

7.6.1 General

There are two fundamental allocation methods, which may be applied on a volume, mass, molar, or energy basis.

Proportional allocation method should be used unless the allocation by difference method is agreed upon by all parties. The allocation by difference may be used when dissimilar measurement systems (e.g. meter types, flow rates, uncertainties) are in the same allocation tier.

7.6.2 Proportional Allocation

The proportional allocation method distributes the resultant end quantity of a process back to the contributing sources based on the ratio of theoretical contribution of the source to the total theoretical contribution of all sources.

\[
Q_{n, End} = Q_{End} \times \frac{NTQ_{n, theo}}{\sum NTQ_{theo}} \quad (24)
\]

Where:
- \( n \) Allocation source
- \( Q_{end} \) End quantity to be allocated
- \( NTQ_{n, theo} \) Source net theoretical quantity

7.6.3 Allocation by Difference

The allocation by difference method allows one or more sources to be “kept whole” or excluded from the proportioning process. The theoretical quantity of the excluded sources is subtracted from the end quantity. The remaining end quantity is distributed to the remaining sources on a ratio of theoretical quantity to total theoretical quantity of the remaining sources.

NOTE: The “kept whole” measurement point may gain or lose based on the measurement of the other allocation tier sources.

Excluded Source

\[
Q_{Excl, End} = Q_{Excl, theo} \quad (25)
\]

Remaining Sources

\[
Q'_{End} = Q_{End} - Q_{Excl, End} \quad (26)
\]

Where:
- \( Q_{excl, end} \) Excluded source allocated quantity
8 Implement Production Measurement and Allocation System

8.1 General

Implementation of the PMAS shall be in accordance with the roles and responsibilities referenced in Section 5.2 and the acceptance criteria in Section 5.6.

Procedures for performing allocations shall be established and documented prior to PMAS operations. The procedures should include information detailing the sequence of events, data acquisition and adjustments (if necessary) executed during the allocation process.

Documentation and record retention policies shall be instituted by the operator to provide an audit trail of the PMAS and allocation results.

Each PMAS shall include:

- MAPFD (refer to Section 8.2),
- Equipment list for allocation inputs (refer to Section 8.3),
- Allocation algorithm (refer to Section 8.4),
- Equipment verification (refer to Section 8.5),
- Fluid analysis (refer to Section 8.6),
- Data handling and storage (refer to Section 8.7),
- Contingency plan (refer to Section 8.8),
- Phase behavior calculation basis (refer to Section 8.9),
- Well testing application basis, if applicable (refer to Section 8.10).

In addition to documented PMAS requirements, recorded information and data should include:

- Performance specifications associated with PMAS equipment (e.g. meter uncertainty),
- Software versions for all associated computer calculations.

8.2 Measurement and Allocation Process Flow Diagram (MAPFD)

The MAPFD shall be based on the PMAS material balance (refer to Section 6.5) and clearly show all of the major flow points, including:

- Inflow quantity points,
- Commingling junctions,
- Measurement points,
- In-process consumed quantity points,
- Recirculation points,
- Accumulated quantity points,
- Outflow quantity points.

Regardless of the detail contained in the MAPFD, at a minimum, the MAPFD shall show the interaction between commingled flows or commingled production, show the placement of primary measurement equipment used in the allocation formulation and logic, and identify measurement equipment with tag numbers identical to those used in other documentation such as the equipment list (refer to Section 8.3). It shall also show the application of phase behavior in allocation formulations in accordance with API Draft

The MAPFD shall have sufficient detail to serve as a basis for allocation logic.

NOTE MAPFDs are used to understand the PMAS. The MAPFD shows the primary measurement system equipment in relationship to the overall flow process.

The MAPFD may use color-coding to depict gas and liquid streams and produced water, and may use symbols to show metering points, metering types, sampling points, and sampling systems.

The MAPFD may also show other significant non-measurement facilities and equipment, such as treating units, compressors, pumps, separation vessels, heat exchangers, heaters, dehydrators, and other equipment that changes the flow characteristics or other flow parameters that affect measurement.

Refer to Annex A or Annex B for an example MAPFD.

8.3 Measurement Equipment Lists for Allocation Inputs

Measurement equipment lists for allocation inputs shall document the measurement system equipment used in the PMAS. The measurement equipment lists shall use the same identification label or tag number as shown on the MAPFD (refer to Section 8.2).

NOTE Measurement equipment lists clarify the range and functionality of the measurement equipment. Generally, measurement equipment that creates a result routinely used in the computation of flow measurement quantities is considered primary measurement system equipment. Primary measurement system equipment typically includes flow meters, pressure and temperature devices, online analyzers, sampling systems, quality measurement equipment, and flow computers.

While the information in the measurement equipment list depends on the type of equipment, at a minimum the measurement equipment list should indicate the equipment’s operating range, in order to facilitate performance evaluations under actual flowing conditions.

The measurement equipment list may record the model number, serial number, and other basic identification information.

NOTE Recording equipment serial numbers is not useful except for equipment that is specifically factory calibrated. However, recording the model number is useful since it allows for identification of original factory specifications supplied by the manufacturer.

Refer to Annex A for an example measurement equipment list.

See Table 3 for examples of equipment list entries for various types of equipment. Note that this list includes the specifications that directly affect measurement performance and may include non-permanent assets such as well test trailers. Additional information, such as temperature specifications and pressure drop information, may also be included in the list.
Table 3–Example of equipment list entries

<table>
<thead>
<tr>
<th>Turbine Meters</th>
<th>Differential Meters</th>
<th>Static Pressure Transmitter</th>
<th>Temperature Transmitter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tag number</td>
<td>Tag number</td>
<td>Tag number</td>
<td>Tag number</td>
</tr>
<tr>
<td>Pipe Size</td>
<td>Pipe Size</td>
<td>Type</td>
<td>Type</td>
</tr>
<tr>
<td>Pressure rating</td>
<td>Pressure rating</td>
<td>Manufacturer</td>
<td>Manufacturer</td>
</tr>
<tr>
<td>Type</td>
<td>Type</td>
<td>Model</td>
<td>Model</td>
</tr>
<tr>
<td>Manufacturer</td>
<td>Manufacturer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Model</td>
<td>Model</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low flow range</td>
<td>Low DP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High flow range</td>
<td>High DP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nominal K-factor</td>
<td>Minimum diameter ratio</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Linearity</td>
<td>Maximum diameter ratio</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Repeatability</td>
<td>Plate thickness if applicable</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

8.4 Allocation Algorithm
The allocation algorithm documentation should provide a clear and auditable list of the allocation formulation and methods used in the PMAS, and shall include at a minimum the following:

- Input data,
- Logic,
- Equations,
- Calculation sequence,
- Primary reported allocation results,
- Output data,
- Acceptance verification.

The equations and calculation sequence in the allocation algorithm documentation may be in the form of a diagram or a list.

8.5 Equipment Verification
Documentation that describes all calibration, validation, and analytical activities both on site and in laboratories shall be provided for all measurement equipment used in the PMAS. This documentation should clearly identify the frequency of activities, all specifically cited reference standards, and any as-found threshold limits that constitute a trigger for further work or correction.

8.6 Fluid Quality Verification
Documentation that describes all PMAS fluid quality related information and activities shall be provided. This documentation should clearly identify the frequency of activities, all specifically cited reference standards, along with fluid quality validation parameters and associated acceptance criteria (refer to Section 9.5).
Fluid quality verification documentation shall address the fluid properties used in the PMAS, for both fluid quantity determination and allocation (e.g. fluid composition).

A fluid sampling plan should be developed and implemented to support fluid quality verification for the PMAS. The fluid sampling plan should include the following objectives:

- Determine PMAS fluid sample requirements,
- Evaluate sample points and sampling infrastructure for viability,
- Coordinate with other engineering disciplines requiring fluid sampling,
- Establish specific sampling and analysis techniques, protocols and procedures, along with sampling frequency.

NOTE API MPMS Chapter 20.5 addresses fluid quality verification for production well testing in detail, and may be used as a reference for PMAS fluid quality verification.

### 8.7 Data Handling and Storage

The data handling and storage plan shall at a minimum include the following:

- Data flow diagram,
- List of data sources,
- Data transmission paths and types,
- Data security protocols,
- Data storage and archival process.

PMAS data shall be protected from unauthorized access. A minimum set of data shall be retained so that quantities can be recalculated to reconcile the effects of agreed measurement errors.

The integrity of the data acquisition, storage, transmittal, and archival system should be designed and maintained to avoid data loss. PMAS data shall be maintained for a defined time period based on regulatory and commercial requirements (refer to Section 5).

### 8.8 Contingency Plan

Contingency plans for PMAS operations shall be established and documented prior to initiating allocations. Contingency plans shall address at a minimum the following:

- Missing data and use of default values,
- Measurement equipment health indicators,
- Fluid measurement system equipment failure or error,
- Unbalanced uncertainties between allocation input points,
- Incorporation or removal of PMAS inputs,
- Allocation data that does not meet acceptance criteria,
- Reconciliation of mis-allocated quantities.

### 8.9 Phase Behavior Calculation Basis

The phase behavior calculation basis shall document the application of phase behavior in the allocation formulations.

NOTE The phase behavior application basis describes the process that accounts for evolved gases from liquid flows and condensed liquids from gas flows, in order to compare inflow, outflow, consumed and accumulated quantities in the PMAS.
Phase behavior calculations that require the use of a process simulation model incorporating an equation of state description of phase behavior shall be developed, implemented and managed in accordance with API Draft Standard *Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems*.

### 8.10 Well Testing Application Basis

The well testing application basis shall be in accordance with API *MPMS* Ch. 20.5.

**NOTE** Periodic well test results are often used as an input for allocation. Therefore, it is important to know the details concerning the conversion of periodic flow measurement results into results that are relevant over the entire allocation time period. Additionally, it is useful to know the uncertainty envelope for the well testing measurement systems and how the uncertainty relates to the performance expectations and capability of the PMAS.

### 9 Operate and Manage Production Measurement and Allocation System

#### 9.1 General

Operation and management of a PMAS shall include routine review of PMAS design and implementation, continuous monitoring and reporting of KPIs, and use of a systematic framework that identifies and resolves out-of-tolerance performance.

Operation and management of a PMAS shall be in accordance with the roles and responsibilities referenced in Section 5.2.

#### 9.2 Performance Capability Assessment

Documentation addressed in Section 8 should be used as a basis for assessing the performance capability of a PMAS. At a minimum a PMAS performance capability assessment shall determine an expected range of material balance between the inflow and outflow quantities, accounting for consumed and accumulated quantities.

**NOTE** The performance capability assessment provides all parties of the commingled flow arrangement a basis for evaluating nominally acceptable performance and assessing risk.

The material balance expected range should include both the largest and smallest anticipated imbalance distributions (refer to Figure 8 – Example PMAS Performance Capability Assessment). The largest imbalance should be used to define the out-of-tolerance limit, referred to as ‘worst to allow’, and should be used to determine when action is taken to improve PMAS performance. The smallest imbalance should be used to define the ‘best to expect’ performance a PMAS can achieve, where additional actions are not likely to return improved PMAS performance.

**NOTE** Often in a PMAS, there are inherent biases that influence the material balance and keep a PMAS from achieving a ‘best to expect’ material balance beyond a certain point of improvement. Additionally, a material balance on an allocation tier (refer to Section 9.5) might not provide adequate insight on biases within the allocation tier, particularly when individual biases offset (e.g. individual theoretical quantities biased high can be offset by similarly equated theoretical quantities biased low).
9.3 Review

A complete PMAS review shall be performed at minimum once a year. The review shall consist of:

- An evaluation of all requirements identified for the PMAS,
- An assessment of the basis of allocation (i.e. the requirements of Section 6), the definition of the allocation process (i.e. the requirements of Section 7), the implementation documentation of the PMAS (i.e. the requirements of Section 8) and acceptance criteria (i.e. the requirements of Section 5.6) used in the PMAS against the documented requirements,
- An assessment of the basis of allocation (i.e. the requirements of Section 6), the definition of the allocation process (i.e. the requirements of Section 7), the implementation documentation of the PMAS (i.e. the requirements of Section 8) and acceptance criteria (i.e. the requirements of Section 5.6) used in the PMAS against current production process conditions for applicability.

All discrepancies identified in the PMAS review shall be documented.

9.4 Modifications

All applicable PMAS modifications shall be documented. This includes changes resulting from:

- Technically justified modifications identified during the PMAS review,
- Process changes impacting the PMAS (e.g. new inflow or outflow quantities).

A management of change documentation process shall be used to document:

- The original PMAS specification,
- The PMAS modification,
- The reason for the modification,
- The demonstrated impact of the change (e.g. an allocation software update can introduce slightly different outputs).

All PMAS modifications shall be communicated to the affected parties. Prior to implementing modifications, a technical review committee among the affected parties should review the proposed modifications.
9.5 Performance Monitoring and Reporting

Key Performance Indicators (KPIs) shall be established to monitor PMAS performance. At a minimum, the KPIs listed in Table 1–PMAS KPIs shall be used.

**Table 1–PMAS KPIs**

<table>
<thead>
<tr>
<th>KPI</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>PMAS Balance factors (oil, water, gas volume, gas energy) on allocation tiers</td>
<td>Overall percentage agreement among inflow, outflow, accounting for consumed and accumulated quantities</td>
</tr>
<tr>
<td>Flow meter inspection, verification/calibration or configuration results</td>
<td>For example, metrology control charts, as-found/as-left transmitter results, inspection reports, or configuration reports</td>
</tr>
<tr>
<td>Sampling and compositional analysis results</td>
<td>Sampling errors, variance in compositional results or energy content results</td>
</tr>
<tr>
<td>As-found variation on pressure and temperature transmitters</td>
<td>As-found results for pressure and temperature transmitters</td>
</tr>
<tr>
<td>Occurrences of missed or late measurement verification activities</td>
<td>Missed or late measurement verification activities (e.g., no sample collected, meter proving past due)</td>
</tr>
</tbody>
</table>

The PMAS balance factor shall be defined as:

\[
PMAS\ Balance\ Factor = \frac{\text{Theoretical Quantity} - \text{Allocation End Quantity}}{\text{Allocation End Quantity}} \times 100\%
\]  

(27)

The most common key performance indicator (KPI) used in allocation is the comparison of these two values. Typically, the acceptance criteria for allocation results is to have this comparison fall within an identified range.

When this KPI is outside an acceptable range, it is a clear indication of a problem. However, when this KPI is within an acceptable range, it should not be seen as a clear indication that the allocation is functioning properly or equitably. Internal inaccuracies can be offsetting and not obvious at the system level. In this scenario, inaccuracies at best are random. At worst, they are biased.

The material balance equation (see section 6.5) can be used as an additional KPI to quantity mass in vs. mass out (including accumulated and consumed quantities). This can help identify if the imbalance is related to measurement issues that are not apparent in the PMAS Balance Factor. Alternatively, it can identify problems with the application of PVT data if the measurement data is accurate.

For each KPI, out-of-tolerance limits shall be established. These limits should be updated periodically to account for changes in the physical characteristics of the system (pressures, temperatures, flow rates, water fraction etc.).

KPIs and any deviations beyond the out-of-tolerance limits should be reported in a manner agreed to by the affected parties.

9.6 Out-of-Tolerance Performance Management

A documented process shall be developed for managing PMAS out-of-tolerance performance. The process should include:

- Out-of-tolerance incident tracking and reporting,
- Identification of out-of-tolerance root causes,
- Recommendations and resolution of out-of-tolerance events (including timing requirements),
- Updates to the PMAS (if required),
- Reporting to affected parties and shared lessons learned.
Annex A
(informative)

Example PMAS for an Onshore Field

The following examples are merely examples for illustration purposes only. They are 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.

A.1 Onshore Scenario Description

For the purpose of illustrating examples of various components regarding a production measurement and allocation system, an onshore production scenario has been construed. The scenario consists of one multi-well production field that are considered as one source in the commingled flow, and three single well operations. There is varying hydrocarbon composition and ownership. A graphical depiction of the scenario is provided in Figure A.9.

There are two operators involved in the scenario. Operator 1 maintains the production and reservoir management responsibility for Field A and Field C because they are the majority owner. Likewise Operator 2 maintains the production and reservoir management responsibility Field B because they are majority owner. Operator 1 operates the central processing facility (CPF). The production ownership is given in Table A.2.

<table>
<thead>
<tr>
<th>Field</th>
<th>Wells</th>
<th>Operator 1 Ownership Percentage</th>
<th>Operator 2 Ownership Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field A</td>
<td>Well 1</td>
<td>90 %</td>
<td>10 %</td>
</tr>
<tr>
<td></td>
<td>Well 2</td>
<td>70 %</td>
<td>20 %</td>
</tr>
<tr>
<td></td>
<td>Well 3</td>
<td>70 %</td>
<td>20 %</td>
</tr>
<tr>
<td>Field B</td>
<td>Well 4</td>
<td>0 %</td>
<td>100 %</td>
</tr>
<tr>
<td></td>
<td>Well 5</td>
<td>0 %</td>
<td>100 %</td>
</tr>
<tr>
<td>Field C</td>
<td>Well 6</td>
<td>100 %</td>
<td>0 %</td>
</tr>
</tbody>
</table>

Field A (wells 1-3) is lean gas and Field B (well 4-5) is rich gas production. The combination of Field A and Field B are called Gas Production Sources (GPS). Conversely, Field C (Well 6) represents oil production. Flows from GPS upon exiting the field or well separation are commingled into a multiphase flow line that terminates at the central processing facility (CPF) inlet separator. The inlet separator provides the primary oil, gas, and water separation and measurement of each. Gas is routed to compression and water is routed to an onsite holding tank. The oil from the inlet separator is routed to a heater treater where addition water is removed to the water tank.

Additionally, trucked oil from well 6 is measured via the trucked oil LACT unit (DMP-101), stored in the wet oil tank (WOT) and eventually routed to the heater treater. Sales oil is routed form the heater treater to the dry oil tank (DOT) (DMP-002). The oil sales measurement occurs downstream of the DOT via sales oil LACT (DMP-001) unit.

Wells 1-5 (GPS) are located on privately owned land and well 6 is located on government owned/controlled land. The government entity normally requires that oil and gas quantities from their lands be measured to custody transfer levels before commingling with non-governmental production. Therefore, Operators 1 and 2 agree to allocate the oil at the CPF to well 6 based solely on the measured volume at the trucked oil LACT (DMP-101) (i.e. held whole).

Other general details include:
a) Field A produces very lean gas (2.5 bbls/mmscf) at separator conditions to process end points  
b) Field B produce very rich gas (25 bbls/mmscf) at separator conditions o process end points  
c) All measurements in the PMAS are continuous except for wells 1-3 in Field A. These well quantities are based on periodic well tests  
d) GPS produce less than 1 % water in the associated oil stream at the CPF  
e) Well 6 gas flows to a third party gas gathering system  
f) The CPF produces saleable gas to an interstate pipeline  
g) Well 6 oil is trucked to CPF and is considered dead oil but may contain up to 5 % water  
h) All water is trucked to a disposal facility  
i) Fuel gas can be purchased from a nearby facility or produced gas may be used  
j) There is both oil and water inventory at the Well 6 location and the CPF  
k) For the CPF, a water allocation is performed to equitably share disposal costs  
l) CFP electricity is supplied by a utility company and the cost is shared via handling fees based on CFP allocated oil volumes  

Figure A.9 Onshore Scenario Overview
The current production rates are illustrated in Table A.3

<table>
<thead>
<tr>
<th>Field</th>
<th>Wells</th>
<th>Oil (BPD)</th>
<th>Gas MSCFD</th>
<th>Water BPD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field A</td>
<td>Well 1</td>
<td>7.5</td>
<td>3000</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>Well 2</td>
<td>12.5</td>
<td>5000</td>
<td>0.75</td>
</tr>
<tr>
<td></td>
<td>Well 3</td>
<td>10.0</td>
<td>4000</td>
<td>0.6</td>
</tr>
<tr>
<td>Field B</td>
<td>Well 4</td>
<td>300</td>
<td>40000</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td>Well 5</td>
<td>375</td>
<td>50000</td>
<td>3.0</td>
</tr>
<tr>
<td>Field C</td>
<td>Well 6</td>
<td>3000</td>
<td>50000</td>
<td>300</td>
</tr>
</tbody>
</table>

A.2 Identify PMAS Requirements

A.2.1 Roles and Responsibilities

Although there are two operators involved in the scenario, Operator 1 is responsible for the development, implementation, operation, performance management and maintenance of the entire PMAS. This helps maintain consistency from the custody transfer measurement to the field and well level allocation measurement. Table A.4 provides a description of the typical roles and responsibilities for the primary operator (Operator 1) for this scenario. This is only an example and companies may be organized differently.

Operator 2 maintains the production and reservoir management responsibility for Wells 4 and 5 because they are the only owner. They also share these responsibilities for Wells 1-3 which they co-own with Operator 1. Also, the gas and oil transporter companies have the responsibility of performing measurement operations for the gas and oil sales measurement kit and producing measurement tickets and other related reports. The same is true for the operator of the offsite fuel gas supply.

Table A.4 — PMAS Roles and Responsibilities

<table>
<thead>
<tr>
<th>Role</th>
<th>Responsibility</th>
</tr>
</thead>
</table>
| Facility Operations           | • Assures data acquisition and transmittal and can be involved in creating daily reports (i.e. daily production report)  
                                | • Maintain, verify, calibrate equipment, and perform physical sampling, and sample handling, and issues field reports.  
                                | • Perform analytical tests, report results, and associated QA.  
                                | • Follow set standard procedures and processes. |
| Hydrocarbon Accounting        | • Performs allocation calculations, data analytics, detects out-of-tolerance performance, issues associated reports, and leads performance improvement efforts  
                                | • Reports quantities to government and uses data for revenue, tax, and other accounting functions |
| Production Operations / Reservoir Management | • Uses data to understand field / Wells and optimize production quantities, adjust Well testing programs  
                                              | • Establishes Well testing program and Well test acceptance criteria  
                                              | • Estimates decline rates  
                                              | • Uses data in reservoir modelling and longer term reserves management |
| Commercial/Auditing           | • Perform measurement and cost allocation audits, verify compliance with regulations requirements and commercial agreements |
| Marketing                     | • Coordinate pipeline nominations  
                                | • Assist in gas balancing |
A.2.2 Governmental and Commercial Requirements

A.2.2.1 Governmental Requirements

Because Well 6 is located on governmental owned/controlled land, all of the measurement related to Well 6 (Field C) is required to be approved by the involved government agency. A variety of applications and permits will be required prior to producing from Well 6. Operator 1 as the government’s lessee for Well 6 will follow the agency’s relative PMAS requirements based on written regulations. The regulations require that governmental related production is processed through to final sales independently. Because the government related production is commingled with non-government related production at the CFP heater treater unit, Operator 1 also prepares justification and seeks a waiver from the agency regarding independent flow measurement.

The agency grants a waiver provided that the truck loading at Well 6 location and unloading at the CFP is metered adequately for security purposes to ensure loss / gain control of the trucking operation. Furthermore, the agency requires that the truck unloading metering at the CPF to be capable of ±0.50% accuracy. Additionally, the agency requires that the oil production assigned to Well 6 equal the volume measured by the truck unloading metering with adjustment for inventory changes in the wet oil tank (WOT) at the CPF (i.e. held whole). The only exception to the hold-whole procedure is the case where the oil material balance of the CPF exceeds ±2%. If there is a larger material balance variance (above ±2%), the agency requires Operator 1 to confirm Well 6 oil volume or show justification to make an adjustment.

Governmental reporting, meter proving, and equipment validation/calibration frequency is monthly.

A.2.2.2 Commercial Requirements

A.2.2.2.1 General

A.2.2.2.1.1 All production is sampled, metered, allocated and reported monthly, in accordance with the provisions of the PHA as per Measurement and Allocation Section under Article 7 - Operations; Measurement and Allocation.

A.2.2.2.1.2 Measurement and allocation procedures are performed in accordance with PHA Exhibit L, Measurement & Allocation Procedures, and subject to and in accordance with governmental regulations and relevant permits.

A.2.2.2.1.3 Operator 1 will enter into separate agreements with oil and gas gathering and transportation entities and fuel gas supplier. These agreements will establish custody transfer measurement procedures for Sales Oil, Sales Gas, and Offsite Purchased Fuel Gas.

A.2.2.2.1.4 Operator 1 purchases electrical power for the CPF and accesses the costs via the production handling fees.

A.2.2.2.1.5 The fuel gas consumed at the CPF is only related to gas production.

A.2.2.2.1.6 Purchased fuel gas costs are based on daily allocated gas volumes and relative to the days fuel is purchased and are assessed via the production handling fees.

A.2.2.2.1.7 For Field A and Field B an Equation of State (EOS) model is used to determine theoretical quantities.

A.2.2.2.1.8 Oil quantities are volumes in units of barrels (42 US Gallons) at 60 F and 0 psig.
A.2.2.2.1.9 Gas quantities are measured using the following units:
   a) Differential pressure for differential pressure type meters is inches of water column (IWC)
   b) Volume is cubic feet at 60 deg. F and 14.70 PSIA (i.e. SCF)
   c) Energy content is British Thermal Units (BTU)
   d) Components are in mole fraction
   e) Gas energy is based on a C10+ analysis where the component BTU values are multiplied by energy content (BTU/SCF) are multiplied by the relevant mole fractions (percent mole) times the relevant gas volume (SCF)
   f) The C10+ fraction is assigned a composition of 100% C10.

A.2.2.2.2 Tier Structure

A.2.2.2.2.1 For the purpose of understanding the allocation process, the PMAS is subdivided into three tiers plus level 0. Level 0 contains the PMAS reference measurements.

A.2.2.2.2.2 Oil reference measurements are:
   a) oil sales (DMP-001),
   b) inventory change in the DOT (DMP-002),
   c) and because of the hold whole situation the Trucked LACT (DMP-101) and inventory change in the WOT (DMP-102) are treated as reference measurements.

A.2.2.2.2.3 Gas reference measurements are:
   a) gas sales (DMP-003),
   b) fuel gas (DMP-004),
   c) purchased fuel gas DMP-005), and
   d) flare (DMP-006)

A.2.2.2.2.4 Water reference measurements are:
   a) Trucked out disposal water (DMP-007),
   b) Inventory change in the CPF Water Tank (DMP-008),
   c) Sales LACT water volume fraction (DMP-001),
   d) and because of the hold whole situation the Trucked LACT (DMP-101) water volume fraction is treated as a reference measurement

A.2.2.2.2.5 Tier one of the allocation includes measurements into the CPF and the reference measurements as the outflow quantities. The reference quantities represent outflow quantities or modifiers to outflow quantities. The input quantities are the Trucked Oil (DMP-101), the inventory change in the WOT (DMP-102), and the gas and liquids from the Gas Production Sources (GPS).

A.2.2.2.2.6 Tier two of the allocation involves two segments, the GPS quantities and the quantities assignable to Well 6.
   a) For Well 6 the allocated quantities are:
      i. Oil includes Trucked Oil measured at the CPF and any hydrocarbon liquids allocated from 3rd parties
ii. Water includes the water volume determined at the Trucked Oil LACT (DMP-101) plus any water allocated from 3rd parties and the metered water at the Well 6 location (DMP-206).

iii. Well 6 allocated gas is the allocated gas from the 3rd party gas gathering company.

b) For the GPS (i.e. Field A and Field B) tier two allocation involves:

i. Both oil and gas theoretical quantities for GPS are determined via an EOS model utilizing input measurements from DMP-201 through DMP-204. Once the theoretical quantities are established they are used to proportionally allocation the allocated GPS oil and gas quantities from tier one.

ii. The water volume assigned to GPS in the tier one allocation is allocated proportionally based on the theoretical water volumes measured at each of the Field A and Field B separators.

A.2.2.2.7 Tier three oil, gas, and water quantities are is based on Field A allocated quantities, allocated proportionally to Wells 1, 2, and 3, based on periodic well tests.

A.2.2.2.3 Material Balance Factors

A.2.2.2.3.1 The balance factor for oil volume, gas energy, gas volume and water volumes are calculated as follows:

$$ Material Balance Factor = \frac{Theoretical Quantity - Reference Quantity}{Reference Quantity} \times 100\% $$

Reference quantity is a CPF outflow quantity or previous tier allocated quantity for oil volume, gas volume, gas energy, or water volume. Material balance factor requirements are on a monthly basis.

A.2.2.2.3.2 Tier one oil material balance requirement is ±2.5 %. The balance equals the sales oil volume and inventory change in the DOT, versus add mixture shrinkage adjusted trucked oil LACT plus inventory change in WOT, and GPS theoretical oil volume at standard conditions.

A.2.2.2.3.3 Tier one gas volume material balance requirement is ±3 %. The balance equals the GPS theoretical gas volume versus sum of non-purchased fuel gas, flare gas and sales gas volume. Because all gas quantities are sourced in the GPS, the tier one and tier two gas volume and gas energy are the same.

A.2.2.2.3.4 Tier one gas energy material balance requirement is ±3 %. The balance equals the GPS theoretical gas energy versus sum of non-purchased fuel gas energy, flare gas energy and sales gas energy. Because all gas quantities are sourced in the GPS, the tier one and tier two gas volume and gas energy are the same.

A.2.2.2.3.5 Tier one water material balance is ±7.5 %. The balance equals the CPF water meter volume plus the inventory change in the CPF water tank plus the sales LACT water fraction volume versus the GPS theoretical water volume plus trucked oil LACT water fraction volume.

A.2.2.2.3.6 Tier two material balance out-of-tolerance (OOT) level is ±5 % for tier 2 theoretical oil volume versus tier 2 allocated oil volume.

A.2.2.2.3.7 Because tier one water volume is determined in a by-difference fashion the tier one and tier two water balance formulation is the same.

A.2.2.2.3.8 The material balance out-of-tolerance (OOT) level is ±10 % for tier 3 well level theoretical oil, gas, and water volumes versus tier 3 allocated volumes.
A.2.2.2.4 Other requirements

Other requirements include but are not limited to:

a) As found / as left transmitter verification and calibration criteria.

b) Meter proving run repeatability and meter factor repeatability

c) Measurement parameter repeatability or reproducibility from one period to the next or based on observed average results, such as shrinkage factors, flash gas factors and flash gas energy content, liquid density, gas density, and watercut.

A.2.2.2.5 Oil Allocation

NOTE: This section describes the allocation method in commercial terms. Refer to Section A.4 for a detailed description of the allocation formulation.

A.2.2.2.5.1 Level zero reference measurement is determined as follows:

a) The Net Standard Volume (NSV) for both the oil sales LACT (DMP-001) and the Trucked Oil LACT (DMP-101) are based on API MPMS Chapters 4, through 11 relating to liquid flow measurement. These measurements have been agreed to be of custody transfer quality level.

A.2.2.2.5.2 Tier one allocation involves the following:

a) The Trucked Oil from Well 6 is treated as a hold whole and the associated volume is equal to the NSV of the Trucked Oil LACT (DMP-101), and the NSV of the inventory change in the WOT (DMP-102).

b) The Gas Production Sources (GPS) oil (i.e. allocated oil quantity for Field A and Field B is equal to the Oil Sales LACT (DMP-001) adjusted for inventory change in the DOT (DMP-002) less Trucked Oil allocated oil volume. This quantity is call GPS allocated oil volume, or \( AOV_{GPS} \).

A.2.2.2.5.3 Both the DOT and WOT volumes are determined by API standard tank gauging and calculation methods per API MPMS Chapter 2, Chapter 3 and Chapter 12. Furthermore:

a) Trucked oil receipts will be halted prior to performing the tank gauging operations for a sufficient time period.

b) Normally, tank gauging will not require shutting in GPS.

A.2.2.2.5.4 Tier two allocated oil involves:

a) For Well 6 the Trucked Oil volume allocated from the CPF is added to any oil volumes allocated to Well 6 from the 3rd party gas gathering operation. This establishes the Well 6 allocated oil volumes. No accounting for inventory change in the Well 6 oil tank is made in the allocation.

b) An EOS model is used to determine theoretical oil volume (TOV) and the composition of the oil of the each individual stream (Field A, Field B) relative to the Oil Sales process point in terms of barrels at standard condition.

c) Additionally, the EOS model is used to establish a liquid composition at Oil Sales process point and thus the liquid density or API Gravity. This is used in a pipeline crude oil quality bank assessment and allocation and VCF corrections as part of the theoretical oil volume calculations.

d) Each source point \((i)\) allocated oil volume (AOV) is determined according to the following equation:

\[
Tier AOV_i = \frac{TOV_i}{\sum_i TOV_i} \times Prev.Tier AOV
\]
A.2.2.2.5 Tier three allocated oil volumes:
   a) Field A, Wells 1, 2, and 3 are allocated from the Field A allocated oil volume proportionally based on periodic well tests. Well tests are performed and theoretical oil volume relative to the wells test is determined for each well per API MPMS 20.5 as a rate in BDP.
   b) The theoretical oil volume for a particular well is the product of rate and the time on production for the well over the allocation period.
   c) Each source point allocated oil volume is determined proportionally according to the following equation:

\[
AOV_{well i} = \frac{TOV_{well i}}{\sum_1^n TOV_{well i}} \times AOV_{FLD A}
\]

A.2.2.2.6 Gas Allocation
NOTE: This section describes the allocation method in commercial terms. Refer to Section A.4 for a detailed description of the allocation formulation.

A.2.2.2.6.1 Sales gas allocation is based on energy (MMBTU) as follows:
   a) Well 6 gas is measured by a third party gas gathering operator and the gas production for Well 6 is based on that measurement. No gas from the CPF gas measurements is allocated to Well 6.
   b) Sales gas energy is based on the Sales Gas energy content relative to the sales gas volume as determined by pipeline operator.
   c) Because Well 6 does not participate in the CPF gas allocation, the allocated gas for the commingled production from Field A and Field B is equal to the sales gas quantity in terms of both volume and energy.

A.2.2.2.7 Fuel Gas, Flare and Electrical Energy Allocation
NOTE: This section describes the allocation method in commercial terms. Refer to Section A.4 for a detailed description of the allocation formulation.

A.2.2.2.7.1 Fuel gas and flare quantities allocation is based on a volume basis only. The fuel and flare volumes are only used to help reservoir management to manage the reserve estimates. The following applies:
   a) Consumed fuel equals the meter fuel volume minus the purchased fuel volume.
   b) Tier two Gross Theoretical Gas Volume is used to establish the fuel and flare volume distribution for Field A and Field B.

A.2.2.2.7.2 The allocated fuel and flare volume to the field-level or well-level is added to the allocated sales volume. This is reported to Reservoir management to apply to their field or well depletion estimates, which also helps to substantiate the current oil in place and gas in place estimates.

A.2.2.2.7.3 Purchased fuel gas and purchased electrical power costs are applied in the cost allocation per the proportion of allocated gas volume and allocated oil volume respectively.

A.2.2.2.8 Water Allocation
NOTE: This section describes the allocation method in commercial terms. Refer to Section A.4 for a detailed description of the allocation formulation.

A.2.2.2.8.1 Produced water quantities used for allocation are in units of barrels (42 US Gallons@ 60°F).
A.2.2.2.8.2 Level 0 (reference) water volume is the water metered at the outlet of the CPF water tank plus the inventory change in CPF the Water Tank plus the water fraction volume of the Sales Oil LACT unit.

A.2.2.2.8.3 The volume for the WOT is determined by API MPMS Ch. 3 procedures based on established tank tables in accordance with API MPMS Ch. 2.

A.2.2.2.8.4 Produced water allocation (Tier 1) will be performed on a volume basis as follows:

a) Trucked Oil allocated water volume is equal to the Trucked Oil LACT GVS oil volume times the water cut percentage as determined at the associated automatic sampler.

b) The combined allocated water quantity for Field A and Field B is equal to the GSV Oil Sales LACT oil volume times the Oil Sales LACT water cut percentage as determined at the Oil Sales LACT plus the CPF Water Meter, less the Trucked Oil allocated water quantity.

A.2.2.2.8.5 GPS (Tier 2) are allocated water as set forth above based on their respective theoretical water quantities, proportionally.

a) Field A theoretical water volume is based on the Field A metered liquid volume times the average water fraction percentage over the month, plus the water volume measured at test separator and production separator water leg meters.

b) Field B, Well 4 and Well 5, theoretical water volume is based on separator metered liquid volume times the water cut percentage measured by Water-in-Oil (WIO) analyzer.

c) For each field or well the allocated water volume is determined according to the following equation:

$$ AWV_{FLD A} = \frac{TWV_{FLD A}}{\sum TWV_{FLD A+B}} \times AWV_{GPS} $$

$$ AWV_{Well 4} = \frac{TWV_{Well 4}}{\sum TWV_{FLD A+B}} \times AWV_{GPS} $$

$$ AWV_{Well 5} = \frac{TWV_{Well 5}}{\sum TWV_{FLD A+B}} \times AWV_{GPS} $$

A.2.2.2.8.6 Wells 1, 2, and 3 are allocated the Field A allocated water volume, proportionally based on periodic well tests.

a) The theoretical water volume for each well (i.e. W1, W2, and W3) is based on well test separator oil meter times the S&W percentage based on spot samples taken during the well test, plus the metered water volume from the well test separator water leg meter accumulated volume over the well test period.

b) The well test water rate is stated in terms of barrels per day. The theoretical water volume for a particular well is the product of the well test rate and the days on production for the well over the allocation period (month).

c) Each source point allocated water volume is determined according to the following equation:

$$ AWV_{well i} = \frac{TWV_{well i}}{\sum TWV_{well i}} \times AWV_{FLD A} $$

A.2.2.2.8.7 Well 6 reported water production is the sum of the Well 6 allocated water volume (from tier 1) and the trucked away water metered at the Well 6 location.
A.2.3 Reservoir / Production Management Requirements

Beyond oil, gas and produced water volumes, reservoir and production management requires production rate along with pressure and temperature data, e.g. at bottomhole and wellhead locations. Reservoir / Production management requirements for the PMAS are as follows:

a) Well rate determination test results
b) Monthly well produced accumulated volumes
c) Monthly well average rates
d) Estimated daily well produced gross volumes

A.2.4 Acceptance Criteria

A.2.4.1 General

A.2.4.1.1 The acceptance criteria for measurement results are to be used to establish an agreed level of discrepancy the suspect errant measurements and request further interrogation. Table A.5 provides a list of routine KPIs and acceptance criteria that will be monitored and reported. However, this does not limit a party from making a claim of mismeasurement. The KPIs listed below are not exhaustive regarding what may be required in any particular situation.

Note: Because this is an example only generic KPIs are listed. It is likely that many more KPIs can be included in actual operations.

<table>
<thead>
<tr>
<th>Key Performance Indicator (KPI)</th>
<th>Acceptance Level</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Material Balances</td>
</tr>
<tr>
<td>Tier 1 oil balance</td>
<td>±2.5 %</td>
</tr>
<tr>
<td>Tier 1 Gas Volume Balance</td>
<td>±3 %</td>
</tr>
<tr>
<td>Tier 1 Gas Energy Balance</td>
<td>±3 %</td>
</tr>
<tr>
<td>Tier 1 Water Balance</td>
<td>±7.5 %</td>
</tr>
<tr>
<td>Tier 2 oil</td>
<td>±5 %</td>
</tr>
<tr>
<td>Tier 2 gas volume balance (same as tier 1)</td>
<td>±3 %</td>
</tr>
<tr>
<td>Tier 2 gas energy balance (same as tier 1)</td>
<td>±3 %</td>
</tr>
<tr>
<td>Tier 2 water balance (same as tier one)</td>
<td>±7.5 %</td>
</tr>
<tr>
<td>Tier 3 oil, gas and water balance</td>
<td>±10 %</td>
</tr>
<tr>
<td></td>
<td>Liquid allocation meter</td>
</tr>
<tr>
<td>Proving repeatability (5 out of 6 consecutive runs)</td>
<td>±0.5 %</td>
</tr>
<tr>
<td>Liquid Meter Factor variance between proves</td>
<td>≤1 %</td>
</tr>
<tr>
<td></td>
<td>Water cut analyzer versus shakeout comparison</td>
</tr>
<tr>
<td>0-20% Water cut</td>
<td>±1 % abs</td>
</tr>
<tr>
<td>20-60% water cut</td>
<td>±2 % abs</td>
</tr>
</tbody>
</table>
A.3 Select Basis of Allocation

A.3.1 General
The following section describes the basis of allocation for the onshore production scenario, as per the PMAS requirements established in Section A.2. It includes a description of (1) fluids to allocate, (2) allocation period, (3) customary units, and (4) material balance.

A.3.2 Quantities to allocate
The following components of the onshore production scenario will be allocated to the field and well levels:

a) Sales oil and gas volumes
b) Produces water volume
c) Fuel gas and flare gas volumes
d) Sales gas energy

A.3.3 Frequency of Allocation
The allocation frequency is monthly for PMAS reporting purposes. In addition, daily allocation of the sale oil, sales gas and produced water is estimated to the well level. Additionally, meter to meter comparison of the trucking operation is reported daily for security purposes.

A.3.4 Engineering units and physical constants
The following customary units of measure will be used in this example:

a) Oil volume at actual conditions: bbl
b) Oil volume at standard conditions: stb
c) Gas volume at actual conditions: mcf
d) Gas volume at standard conditions: mscf
e) Temperature: °F
f) Pressure: psia
g) Standard Conditions: 14.696 psia, 60 °F
h) For gas: 6,000 scf = 1 BOE
i) Gas Energy: Millions of British thermal units (MMBTU)
j) Pure component physical properties: GPA 2145

<table>
<thead>
<tr>
<th>Transmitters</th>
<th>±0.5 %</th>
</tr>
</thead>
<tbody>
<tr>
<td>As-found variation on differential and static pressure transmitters</td>
<td>±0.5 %</td>
</tr>
<tr>
<td>As-found variation on temperature transmitter</td>
<td>±0.5 %</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Laboratory Conditions</th>
<th>±10 psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas sample bottle pressure heated to separator temperature</td>
<td>±10 psi</td>
</tr>
</tbody>
</table>
A.3.5 Material Balance

A.3.5.1 Allocation Basis Description

Inflows include all oil, gas, and water from Wells 1-5 and the oil from Well 6. Also purchased fuel gas at the CPF is an inflow to the PMAS. Consumed quantities are fuel gas and flare, which are both consumed within the CPF. Outflow quantities are sale gas, sales oil, and produced water, which are all measured at the CPF.

Although there is an oil tank and water tank located at the Well 6 location, they are not included in the allocation logic and thus are not shown in the diagram. Accumulated quantities considered in the allocation are the Wet Oil Tank (WOT), Dry Oil Tank (DOT), and Water Tank all located at the CPF. The material balance scheme for the onshore scenario is illustrated in Figure A.10 Onshore PMAS Material Balance. Measurement points are shown in the “M” boxes in the diagram.

A.3.5.2 Inflow Quantities

The inflow streams for the onshore example are:

a) Commingled stream of Wells 1, 2, 3, 4, and 5 (CPF Inlet Separator)

b) Isolated oil stream from Wells 6 (CPF WOT)

c) Purchased fuel gas
A.3.5.3 Outflow Quantities
The outflow streams for the onshore example are:
   a) Oil Sales stream at LACT
   b) Gas Sales stream
   c) Disposed water

A.3.5.4 Consumed Quantities
The consumed streams for the offshore example are:
   a) Fuel gas
   b) Flare gas
   c) Vent gas

A.3.5.5 Accumulated Quantities
   a) Dry oil tank
   b) Wet oil tank
   c) CPF Water tank

A.4 Allocation Process Definition

A.4.1 General
This section provides details of the allocation process per the allocation basis defined in Section A.3. Included are the following:
   - Delineation of the allocation tiers
   - Identification of the process inputs and outputs
   - Detailed equations for theoretical quantities determination
   - Determination method for the allocated quantities

A.4.2 Allocation Process Considerations

A.4.2.1 Fluid Similarity
In this example there is a variety of fluid types commingled. Field A produces a lean gas while wells 4 and 5 produce rich gas. Well 6 only participate in the PMAS for its oil production, which is considered a medium weight at 35° API gravity. Table A.6 lists a comparison of fluid properties for the gas wells.

Table A.6 Fluid Similarity

<table>
<thead>
<tr>
<th>Component / Parameter</th>
<th>Field A (% mol) (normalized)</th>
<th>Field B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>88.74</td>
<td>71.5</td>
</tr>
<tr>
<td>Ethane</td>
<td>5.34</td>
<td>5.36</td>
</tr>
<tr>
<td>Propane</td>
<td>4.14</td>
<td>4.71</td>
</tr>
<tr>
<td>i-Butane</td>
<td>0.25</td>
<td>1.25</td>
</tr>
<tr>
<td>n-Butane</td>
<td>1.05</td>
<td>2.39</td>
</tr>
<tr>
<td>Component / Parameter</td>
<td>Field A</td>
<td>Field B</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>---------</td>
<td>---------</td>
</tr>
<tr>
<td>i-Pentane</td>
<td>0.05</td>
<td>1.8</td>
</tr>
<tr>
<td>n-Pentane</td>
<td>0.07</td>
<td>4.73</td>
</tr>
<tr>
<td>Hexane</td>
<td>0.06</td>
<td>3.5</td>
</tr>
<tr>
<td>Heptane</td>
<td>0.07</td>
<td>2.75</td>
</tr>
<tr>
<td>Octane</td>
<td>0.05</td>
<td>1.01</td>
</tr>
<tr>
<td>Nonane</td>
<td>0.03</td>
<td>0.4</td>
</tr>
<tr>
<td>Decane +</td>
<td>0.15</td>
<td>0.6</td>
</tr>
<tr>
<td>Total Mole Fraction Percent</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Condensate to Gas Ratio (BBL/MMSCF)</td>
<td>2.5</td>
<td>25</td>
</tr>
<tr>
<td>Condensate Density (Deg. API)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(at CPF heater treater inlet)</td>
<td>86</td>
<td>82</td>
</tr>
</tbody>
</table>

A.4.2.2 Bias

A.4.2.2.1 Liquid quantities determination

A.4.2.2.1.1 Volume change due to mixing dissimilar fluids such as well 6, which is a medium crude oil and condensate yield from the gas wells. This results in a negative bias to the lighter hydrocarbons. The lighter hydrocarbon comes from the GPS fields. The government entity will not agree to share in any negative adjustment citing Operator 1 chose to commingle the Well 6 oil in such a fashion.

A.4.2.2.1.2 Because the volume of liquid from the GPS is small compared to Well 6 oil, Operator 1 has agreed to determine the volumetric value of the admixture shrinkage per API MPMS 12.3 and compensate operator 2 for their relative losses, independently from the PMAS. Also the density at the oil sales will be slightly higher (lower API gravity) due to admixture shrinkage. Operator 1 also compensates Operator 2 for any negative effects for any quality bank credit allocations.

A.4.2.2.1.3 High water cut from trucked oil can increase the uncertainty of the water fraction determination. Because the trucked oil is being held whole in the allocation, the water fraction limit for trucked oil is set at 5%. A WIO analyzer is used at DMP-101 to alarm and shutdown the transfer pump. When the set point is reached the fouling truck is returned to the well 6 location and reprocessed.

A.4.2.2.1.4 Manual sampling for water fraction on wells 1, 2, and 3 versus on-line analyzers on wells 4 and 5. Because the water production in the GPS fields is low this risk has been accepted by the parties.

A.4.2.2.2 Gas quantities determination

Assumption of gas being saturated with water vapor. Because a produced gas can be under-saturated with water, assuming full saturation will negatively affect the volume determination. Currently, there is no indication of under-saturation and the parties have accepted the risk.

A.4.2.3 Continuous vs Periodic Measurement

Within Field A there is a slight difference in ownership between wells 1 through 3. Therefore, the additional uncertainty experienced in periodic versus continuous measurement, can result in increased allocation bias at the well level for field A. Operators 1 and 2 have accepted this additional uncertainty. All other measurements used in the allocation are based on continuous measurements.
A.4.3 Onshore Scenario Allocation Tiers

A.4.3.1 General

This example includes three allocation tiers (see Figure A.9 Onshore Scenario OverviewFigure A.9):

a) Tier one — Oil sales and gas sales, fuel, and flare and water to the inflow sources at the CPF
b) Tier two — CPF inlet separator allocated gas, condensate, and water to the to Field A and Field B
c) Tier three — Field A, Wells 1-3.

A.4.3.2 Tier One

Trucked oil from Well 6 is measured by a LACT quality system and is held whole. The oil allocation at the CPF for Field A and Field B is determined by-difference. Additionally, because the Trucked Oil from Well 6 is only crude oil (e.g. RVP pipeline quality spec), the gas sales, fuel, and flare are totally assignable to Field A and Field B.

A.4.3.3 Tier Two

Tier two allocation starts with the sales gas, fuel, and flare for the allocation of gas quantities. Liquid quantities, assigned by-difference, are taken as the condensate and water allocated quantities. These quantities are allocated to Field A, Well 4 and Well 5 on a proportional basis.

A.4.3.4 Tier Three

Because Well 4 and Well 5 are single wells that are continuously measured, their well level allocation takes place in tier two. Therefore, tier three involves only Field A. This is a well level allocation for Wells 1, 2, and 3. Gas, condensate, and water are allocated proportionally to each well based on production rates determined by periodic well tests applied to production time in the allocation period.

A.4.3.5 Allocation Workflow

Figure A.11 illustrates the allocation workflow. For each tier there are inputs and outputs. The output quantities from a previous tier are inherently used as input to the next tier along with other input quantities introduced at that point in the workflow. Table A.7 lists the meaning of the acronyms.
The following table lists the non-common acronyms used in the allocation description:

### Table A.7 Allocation Workflow Nomenclature

<table>
<thead>
<tr>
<th>Tier</th>
<th>Acronym</th>
<th>Meaning</th>
<th>DMP’s Involved</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>T-1 Oil</strong></td>
<td>Sales LACT</td>
<td>Sales Oil Volume</td>
<td>DMP-001</td>
</tr>
<tr>
<td>Input</td>
<td>DOT INVT</td>
<td>Dry oil tank inventory change</td>
<td>DMP-002</td>
</tr>
<tr>
<td></td>
<td>Trucked LACT</td>
<td>Trucked oil LACT (NSV)</td>
<td>DMP-101</td>
</tr>
<tr>
<td></td>
<td>WOT INVT</td>
<td>Wet oil tank inventory change</td>
<td>DMP-102</td>
</tr>
<tr>
<td><strong>T-1 Oil</strong></td>
<td>W6 AOV&lt;sub&gt;CPF&lt;/sub&gt;</td>
<td>Allocated oil volume assignable to Well 6</td>
<td>DMP-101</td>
</tr>
<tr>
<td>Output</td>
<td>GPS AOV</td>
<td>Allocated oil volume to the gas production sources (GPS) i.e. Field A, Well 4, and Well 5</td>
<td>By-difference</td>
</tr>
<tr>
<td><strong>T-2 Oil</strong></td>
<td>FLD-A TOV</td>
<td>Theoretical oil volume assignable to Field A, Well 4, Well 5</td>
<td>DMP-201, 202, 203, 204</td>
</tr>
<tr>
<td>Input</td>
<td>W4 TOV</td>
<td>Theoretical oil volume assignable to Field A, Well 4, Well 5</td>
<td>DMP-201, 202, 203, 204</td>
</tr>
<tr>
<td></td>
<td>W5 TOV</td>
<td>Allocated oil volume assigned to Well 6 from 3rd party</td>
<td>3&lt;sup&gt;rd&lt;/sup&gt; Party</td>
</tr>
<tr>
<td><strong>T-2 Oil</strong></td>
<td>FLD-A AOV</td>
<td>Allocated Oil Volume for FLD A, W4, W5, W6</td>
<td>DMP-201, 202, 203, 204</td>
</tr>
<tr>
<td>Output</td>
<td>W4 AOV</td>
<td>Theoretical oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td></td>
<td>W5 AOV</td>
<td>Theoretical oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td></td>
<td>W6 AOV</td>
<td>Theoretical oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td><strong>T-3 Oil</strong></td>
<td>W1 TOV</td>
<td>Theoretical oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td>Input</td>
<td>W2 TOV</td>
<td>Theoretical oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td></td>
<td>W3 TOV</td>
<td>Theoretical oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td><strong>T-3 Oil</strong></td>
<td>W1 AOV</td>
<td>Allocated oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td>Output</td>
<td>W2 AOV</td>
<td>Allocated oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td></td>
<td>W3 AOV</td>
<td>Allocated oil volume assignable to Well 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td><strong>T-1 Gas</strong></td>
<td>Sales GV</td>
<td>Sales gas volume</td>
<td>DMP-003</td>
</tr>
<tr>
<td>Input</td>
<td>Sales GE</td>
<td>Sales gas energy</td>
<td>DMP-003</td>
</tr>
<tr>
<td></td>
<td>Fuel GV</td>
<td>Fuel gas volume</td>
<td>DMP-005</td>
</tr>
<tr>
<td>Tier</td>
<td>Acronym</td>
<td>Meaning</td>
<td>DMP's Involved</td>
</tr>
<tr>
<td>--------------</td>
<td>--------------------------</td>
<td>------------------------------------------------------------------------</td>
<td>----------------</td>
</tr>
<tr>
<td>T-1 Gas Output</td>
<td>Pur., Fuel GV</td>
<td>Purchased fuel gas volume</td>
<td>DMP-004</td>
</tr>
<tr>
<td></td>
<td>Flare GV</td>
<td>Flare gas volume</td>
<td>DMP-006</td>
</tr>
<tr>
<td>T-1 Gas Output</td>
<td>GPS AGV/AGE</td>
<td>Allocated gas volume and energy for GPS</td>
<td>DMP-003</td>
</tr>
<tr>
<td>T-2 Gas Input</td>
<td>FLD-A TGV/TGE, W4 TGV/TGE, W5 TGV/TGE</td>
<td>Theoretical gas volume and energy assignable to gas production sources (GPS) i.e. Field A, Well 4 and Well 5,</td>
<td>DMP-201, DMP-202, DMP-203, DMP-204</td>
</tr>
<tr>
<td></td>
<td>W6 AGV/AGE</td>
<td>Allocated gas volume and energy for Well 6 from 3rd party</td>
<td>3rd Party</td>
</tr>
<tr>
<td></td>
<td>W6 AGV/AGE</td>
<td>Allocated gas volume and energy for Well 6</td>
<td>3rd Party</td>
</tr>
<tr>
<td>T-3 Gas Input</td>
<td>W1 TGV/TGE, W2 TGV/TGE, W3 TGV/TGE</td>
<td>Theoretical gas volume and energy for wells 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td>T-3 Gas Output</td>
<td>W1 AGV/AGE, W2 AGV/AGE, W3 AGV/AGE</td>
<td>Allocated gas volume and energy for wells 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td></td>
<td>W1 AFU/AFL, W2 AFU/AFL, W3 AFU/AFL</td>
<td>Allocated fuel and flare for wells 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
<tr>
<td>T-1 Water Input</td>
<td>Sales S&amp;W, Trucked S&amp;W</td>
<td>Water fraction volume of sales oil LACT</td>
<td>DMP-001</td>
</tr>
<tr>
<td></td>
<td>CPF WMV</td>
<td>CPF disposal water meter</td>
<td>DMP-007</td>
</tr>
<tr>
<td></td>
<td>CPF Water Tank Invt</td>
<td>CPF water tank</td>
<td>DMP-008</td>
</tr>
<tr>
<td>T-1 Water Output</td>
<td>W6 AWVCPF</td>
<td>Allocated water volume to well 6 from CPF</td>
<td>DMP-101</td>
</tr>
<tr>
<td></td>
<td>GPS AWV</td>
<td>Allocated water volume to GPS Field A, Well 4, Well 5</td>
<td>By-difference</td>
</tr>
<tr>
<td></td>
<td>W6 MWV</td>
<td>Metered disposal water at well 6 location</td>
<td>DMP-206</td>
</tr>
<tr>
<td>T-3 Water Input</td>
<td>W1 TWV, W2 TWV, W3 TWV</td>
<td>Theoretical water volume for wells 1, 2, and 3</td>
<td>DMP-201</td>
</tr>
</tbody>
</table>
A.4.4 Equations for Theoretical Quantity Determination

Because the oil from Well 6 is held whole in the tier on allocation, only the production from the gas production sources (GPS) are involved in the theoretical quantity determination.

A.4.4.1 General

A.4.4.1.1 The owners of the GPS production have elected to use a thermodynamic model which applies equations of state (EOS) to the separator quantities (volume, composition, pressure, and temperature) to the process end points at the sales gas and sales oil and at the end point conditions (epc) of pressure and temperature. The output of the EOS model is the volume and composition at the process end points (Sales Gas DMP-003 and Sales Oil DMP-001). The results of the EOS model are used to determine shrinkage factor, flash factor, flash gas energy, the gas correction factor. Figure A.12 illustrates the EOS model process.

![Figure A.12 EOS Model Diagram](image)

A.4.4.1.2 Pressure and temperature measurement inputs to the EOS model are based on flow weighted averages relative to the allocation period. Both gas and hydrocarbon liquid (condensate) compositional analysis is to a C10+ basis.

A.4.4.1.3 There are four separators in the GPS. However, the Field A production and test separator volumes are combined to represent only one allocation point for Field A. Following are the separators that the PSM provides values for.

- Field A production separator (DMP-201) + Field A test separator (DMP-202)
Field B well 4 separator (DMP-203)
Field B well 5 separator (DMP-204)

A.4.4.1.4 The theoretical oil and gas volume for each GPS separator is the basis for the Tier 2 allocation of the GPS tier one oil and gas allocated volume. Because the tier one allocated oil volume for the GPS production is determined by-difference, and the tier one gas volume for GPS production is assigned the sales gas volume, theoretical oil and gas volumes relate to only tier two and three of the PMAS.

A.4.4.2 Determination of Theoretical Oil Quantities

A.4.4.2.1 Shrinkage Factor, Gas Correction Factor, and Gas Condensate Ratio

A.4.4.2.1.1 For shrinkage factor the EOS model result of oil volume at the end point conditions is adjusted to standard conditions (SC) via the VCF per the gravity result of EOS model oil composition output. As illustrated in equation 2 and equation 3 in the normative Section 7.4.5.2, the following equation applies for shrinkage factor:

\[
SF_i = \frac{EOV_{Iepc} \times VCF_{Iepc}}{MOV_{Sep Iac}}
\]

Where

- \(SF_i\) = Shrinkage factor for separator \((i)\)
- \(EOV_{Iepc}\) = EOS resultant oil volume for separator \((i)\) at end point conditions
- \(VCF_{Iepc}\) = Volume correction factor relative to end point conditions and oil gravity based on the EOS oil composition result for separator \((i)\)

A.4.4.2.1.2 For gas correction factor \((Bg)\) the EOS model approach is used to predict the hydrocarbon liquids that will condensate between the separator conditions to the end point conditions, given the gas volume and composition. This is based on Equations (4) and (5) in the normative Section 7.4.5.3 and the following equation applies:

\[
B_{gi} = \frac{MGV_{Iapc} \times (1 - X_{WG I apc})}{EOV_{Iepc} \times \left(\frac{P_{g epc}}{P_{sc}}\right) \times \left(\frac{T_{sc}}{T_{g epc}}\right) \times \left(\frac{Z_{g epc}}{Z_{g epc}}\right)}
\]

Where:

- \(B_{gi}\) = Gas correction factor for separator \((i)\)
- \(MGV_{Iapc}\) = Metered gas volume at allocation point conditions \((apc)\)
- \(X_{WG I apc}\) = Water volume fraction in gas at allocation point conditions
- \(EOV_{Iepc}\) = EOS output gas volume at end point conditions \((epc)\)
- \(\left(\frac{P_{g epc}}{P_{sc}}\right) \times \left(\frac{T_{sc}}{T_{g epc}}\right) \times \left(\frac{Z_{g epc}}{Z_{g epc}}\right)\) = Pressure, temperature and compressibility corrections

\(MGV_{Iapc} \times (1 - X_{WG I apc})\) is referred to as “dry” gas volume because it has been volumetrically corrected for water vapor (see section A.4.4.3.2)
A.4.4.2.2 Theoretical Oil Volume

The field level theoretical oil volume consists of two sources; a) Separator liquid outlet, corrected for S&W and shrinkage, and b) Theoretical liquid dropout from the separator gas outlet. Based on Equation (11) in Section 7.5.2 of the normative part of the document, the theoretical oil quantity, determined at separator \((i)\), is as follows:

\[
TOV_{i,sc} = [MLV_{i,apc} \times (1 - X_{w.i,apc}) \times SF_i] + [MGV_{i,apc} \times (1 - X_{wg,i,apc}) \times \frac{1}{BG_i} \times r_{s,i}]
\]

EQ A-3

Where:
- \(TOV_{i,sc}\) Theoretical oil volume for separator \((i)\) at standard conditions \((SC)\)
- \(MLV_{i,apc}\) Measured liquid volume for separator \((i)\) at allocation point conditions \((apc)\)
- \(X_{w.i,apc}\) Water fraction for separator \((i)\) liquid outlet from the online analyser, at \((apc)\)
- \(SF_i\) Oil shrinkage factor for separator \((i)\); see Equation A-1
- \(MGV_{i,apc}\) Measured gas volume for separator \((i)\); at \((apc)\)
- \(X_{wg,i,apc}\) Water volume fraction in the gas, at \((apc)\) (see Equations A-5 and A-6)
- \(BG_i\) Gas correction factor for separator \((i)\); dry gas volume at \((apc)\) over gas volume at \((SC)\) (see Equation A-2)
- \(r_{s,i}\) Condensate-gas ratio of dry gas volume for separator \((i)\); stb/scf (see Section 7.4.5.6 of the normative part of this document)

Table A.8 lists the input data, source and unit for the theoretical oil volume calculation for each of the leases.

**Table A.8 List of Input Data and Source to Calculate Lease Theoretical Oil Volume**

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Source</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field A Production plus Test Separator</td>
<td>(MLV_{FLD A})</td>
<td>DMP-201, DMP-202</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>(X_{w,FLD A})</td>
<td>Manual sampling</td>
<td>water fraction, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>(SF_{FLD A})</td>
<td>EOS Model per Field A Oil volume and composition at separator conditions</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>(MGV_{FLD A})</td>
<td>DMP-201, DMP-202</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td></td>
<td>(X_{wg,FLD A})</td>
<td>Calculated from Eqn A-4</td>
<td>water volume fraction, separator gas condition</td>
</tr>
<tr>
<td></td>
<td>(BG_{FLD A})</td>
<td>EOS Model per gas volume and composition at FLD A Prod. separator conditions</td>
<td>separator cu ft/scf</td>
</tr>
</tbody>
</table>
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<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Source</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field B</td>
<td>$r_{g,FLD\ A}$</td>
<td>EOS calculated using FLD A separator gas composition</td>
<td>stb/scf</td>
</tr>
<tr>
<td>Well 4 Separator</td>
<td>$MLV_{W4}$</td>
<td>DMP-203</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>$X_{w,W4}$</td>
<td>WIO DMP-203</td>
<td>water fraction, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{W4}$</td>
<td>EOS Model per Well 4 oil volume and composition at separator conditions</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$MGV_{W4}$</td>
<td>DMP-203</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td></td>
<td>$X_{wg,W4}$</td>
<td>Calculated from Eqn A-4</td>
<td>water volume fraction, separator gas condition</td>
</tr>
<tr>
<td></td>
<td>$B_{g,W4}$</td>
<td>EOS Model per gas volume and composition at Well 4 separator conditions</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>$r_{s,W4}$</td>
<td>EOS calculated using Well 4 separator gas composition</td>
<td>stb/scf</td>
</tr>
<tr>
<td>Field C</td>
<td>$MLV_{W5}$</td>
<td>DMP-204</td>
<td>separator bbl</td>
</tr>
<tr>
<td>Well 5 Separator</td>
<td>$X_{w,W5}$</td>
<td>WIO DMP-204</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{W5}$</td>
<td>EOS Model per Well 5 oil volume and composition at separator conditions</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$MGV_{W5}$</td>
<td>DMP-204</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td></td>
<td>$X_{wg,W5}$</td>
<td>Calculated from Eqn A-4</td>
<td>water volume fraction, separator gas condition</td>
</tr>
<tr>
<td></td>
<td>$B_{g,W5}$</td>
<td>EOS Model per gas volume and composition at Well 5 separator conditions</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>$r_{s,W5}$</td>
<td>EOS calculated using Well 5 separator gas composition</td>
<td>stb/scf</td>
</tr>
</tbody>
</table>
A.4.4.3 Determination of Theoretical Gas Quantities

A.4.4.3.1 General

A.4.4.3.1.1 An EOS model is used to determine theoretical gas quantities. Therefore, meter gas volume at the GPS separators are corrected for the volume fraction of water vapor.

A.4.4.3.1.2 Because fuel and flare volumes are consumed in the CPF there are both a gross and net gas theoretical gas quantities. The gross theoretical gas quantities are based on the measured gas and relevant flash gas from each separator (i). The net theoretical gas volume (NTGV) is the gross theoretical gas volume (GTGV) minus the fuel and flare allocated volumes for each GPS separator.

A.4.4.3.2 Water Vapor Correction

A.4.4.3.2.1 Gas streams are assumed water saturated and metered gas quantity is reduced for the volume fraction of water vapor based in Equation (15) in Section 7.5.3.2.2 of the normative part of this document. The water vapor fraction in the gas is calculated as follows:

\[ X_{w,g,apc} = 1 - \frac{P_{water\ vapor}}{P_{Total}} \]  

EQ A-4

Where:

- \( X_{w,g,apc} \) = volume fraction of water vapor in the separator gas at (apc)
- \( P_{water\ vapor} \) = partial pressure of water vapor at (apc), psia
- \( P_{Total} \) = separator pressure, psia

Assuming ideal gas and liquid mixtures, the water vapor pressure is determined using the Antoine equation as follows:

\[ P_{water\ vapor} = 10^{A - \frac{B}{C+T}} \]  

EQ A-5

Where:

- \( P_{water\ vapor} \) = partial pressure of water vapor at separator conditions, mm Hg
- \( T \) = separator temperature, °C
- \( A, B, C \) = Antoine equation pure component coefficients

The Antoine equation parameters for water are listed in Table A.9.

### Table A.9 Antoine Equation Pure Component Coefficients

<table>
<thead>
<tr>
<th>Pure Component</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>Temp Min Deg. C</th>
<th>Temp Max Deg. C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>8.07131</td>
<td>1730.63</td>
<td>233.426</td>
<td>1</td>
<td>100</td>
</tr>
</tbody>
</table>

A.4.4.3.3 Gross Theoretical Gas Volume

A.4.4.3.3.1 The gas volume used in the EOS model (EOS GV) for any separator (i) is as follows

\[ EOS\ GV_{i,apc} = MGV_{i,apc} \times (1 - X_{w,g,i,apc}) \]  

EQ A-6

Where

\( EOS\ GV_{i,apc} \) = EOS input “dry” gas volume for separator (i) at allocation point conditions (apc)
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\[ MGV_{i,apc} = \text{Metered gas volume for separator (i) at (apc)} \]
\[ X_{w,g,i,apc} = \text{Water fraction in gas for separator (i) at (apc)} \]

A.4.4.3.3.2 The gas correction factor is based on Equations (4) and (5) in Section 7.4.5.3 of the normative part of this document. The EOS model output for gas volume for separator (i) at the end point conditions (epc) is designated as: \( EOS 
GV_{i,epc} \), and the gas correction factor to adjust to standard conditions is:

\[ B_{g,i} = \frac{EOS \, GV_{i,apc}}{EOS \, GV_{i,epc} \times \left( \frac{P_{g,epc}}{P_{g,apc}} \right) \times \left( \frac{T_{epc}}{T_{g,apc}} \right) \times \left( \frac{Z_{g,sc}}{Z_{g,epc}} \right)} \]

EQ A- 7

A.4.4.3.3.3 The flash factor is the EOS resultant flash gas volume (FGV) for separator (i) adjusted the standard conditions (SC) divided by the TOV, which is also at (SC). This is based on Equation (8) in Section 7.4.5.5 in the normative part of this document.

\[ FF_i = \frac{EOS \, FGV_{i,epc} \times \frac{1}{FGV_i}}{TOV_i} \]

EQ A- 8

A.4.4.3.3.4 For gross theoretical gas volume gas volume result at the end process conditions (epc) is corrected to (SC) as illustrated in Section 7.4.5.3, Equation (4) and Equation (5) of the normative section of this document plus the gas volume evolving for the liquid hydrocarbon as depicted in the flash factor.

\[ GTGV_i = \left[ EOS \, GV_{i,epc} \times \frac{1}{B_{g,i}} \right] + \left[ MLV_{i,apc} \times \left( 1 - X_{w,g,i,apc} \right) \times SF_i \times FF_i \right] \]

EQ A- 9

Where

- \( GTGV_i \): Gross theoretical gas volume for separator (i)
- \( EOS \, GV_{i,epc} \): EOS model resultant gas volume for separator (i) at (epc)
- \( B_{g,i} \): Gas correction factor relative to (epc) and gas composition based on the EOS model gas composition result for separator (i)
- \( MLV_{i,apc} \): Measured liquid volume for separator (i) at allocation point conditions (apc)
- \( X_{w,g,i,apc} \): Water fraction for separator (i) liquid outlet from the online analyser, at (apc)
- \( SF_i \): Oil shrinkage factor for separator (i); see Equation A-1
- \( FF_i \): Flash factor separator (i)

A.4.4.3.4 Allocated Fuel and Flare Gas

A.4.4.3.4.1 All consumed fuel and flare are allocated based on the gross theoretical gas volume (GTGV) of each GPS separator (i) over the sum of GTGV for all separators. For fuel the allocated gas volume is the GTGV portion for separator (i) times the metered fuel consumed minus the purchased fuel as shown in Equation A-10. The allocated flare volume is given in Equation A-11.

\[ AFUG_i = \frac{GTGV_i}{\sum GTGV_i} \times (Fuel_{SC} - PurchasedFuel_{SC}) \]

EQ A- 10

\[ AFLG_i = \frac{GTGV_i}{\sum GTGV_i} \times Flare_{SC} \]

EQ A- 11
A.4.4.3.5 Net Theoretical Gas Volume

A.4.4.3.5.1 The net theoretical gas volume (NTGV) for any separator \((i)\) is the gross theoretical gas volume (GTGV) minus the allocated fuel and flare volume:

\[
NTGV_i = GTGV_i - AFU_i - AFL_i
\]

EQ A- 12

A.4.4.3.5.2 The equation can also be given in expanded form as follows, which is based on a combination of Equations (13) and (14) of Section 7.5.3.2 of the normative part of this document.

\[
NTGV_i = \left[EOS\,GV_{i,epc} \times \frac{1}{B_{g,i}}\right] + \left[MLV_{i,apc} \times (1 - X_{w,i,apc}) \times SF_i \times FF_i\right] - AFUG_i - AFLG_i
\]

EQ A- 13

Where

- \(NTGV_i\): Net theoretical gas volume for separator \((i)\)
- \(EOS\,GV_{i,epc}\): EOS model resultant gas volume for separator \((i)\) at \((epc)\)
- \(B_{g,i}\): Gas correction factor relative to \((epc)\) and gas composition based on the EOS model gas composition result for separator \((i)\)
- \(MLV_{i,apc}\): Measured liquid volume for separator \((i)\) at allocation point conditions \((apc)\)
- \(X_{w,i,apc}\): Water fraction for separator \((i)\) liquid outlet from the online analyser, at \((apc)\)
- \(SF_i\): Oil shrinkage factor for separator \((i)\); see Equation A-1
- \(FF_i\): Flash factor separator \((i)\)
- \(AFUG_i\): Allocated fuel gas for separator \((i)\)
- \(AFLG_i\): Allocated flare gas volume for separator \((i)\)

A.4.4.3.5.3 The inputs used to determine net theoretical gas volume for the GPS separators are listed in Table A.10 Net Theoretical Gas Inputs.

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Source</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field A Production plus Test Separator ((FLD,A))</td>
<td>(EOS,GV_{FLD,A,epc})</td>
<td>DMP-201, DMP-202 EOS Model</td>
<td>cu. ft. at end point conditions ((epc))</td>
</tr>
<tr>
<td></td>
<td>(B_{g,FLD,A})</td>
<td>DMP-201, DMP-202 EOS Model</td>
<td>Gas volume at ((apc)) over gas volume at ((SC)) cu ft (apc/cfSC)</td>
</tr>
<tr>
<td></td>
<td>(MLV_{FLD,A,apc})</td>
<td>DMP-201, DMP-202</td>
<td>Bbls at ((apc))</td>
</tr>
<tr>
<td></td>
<td>(X_{w,FLD,A,apc})</td>
<td>Manual sampling</td>
<td>Water volume fraction at ((apc))</td>
</tr>
<tr>
<td></td>
<td>(SF_{FLD,A})</td>
<td>DMP-201, DMP-202 EOS model</td>
<td>Bbls at ((SC)) over Bbls at ((apc))</td>
</tr>
<tr>
<td>Lease Unit/Separator</td>
<td>Input Data</td>
<td>Source</td>
<td>Unit</td>
</tr>
<tr>
<td>---------------------</td>
<td>------------</td>
<td>--------</td>
<td>------</td>
</tr>
<tr>
<td></td>
<td>$FF_{FLD,A}$</td>
<td>PVT analysis of FLD A separator oil sample</td>
<td>Gas volume at (SC) over Bbls at (SC)</td>
</tr>
<tr>
<td></td>
<td>$AFUG_{FLD,A}$</td>
<td>Attributed from DMP-004 DMP-005</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$AFLG_{FLD,A}$</td>
<td>Attributed from DMP-007</td>
<td>Scf</td>
</tr>
<tr>
<td>Field B Well 4 ($W4$)</td>
<td>$EOS,GV_{W4,epc}$</td>
<td>DMP-203 EOS Model</td>
<td>cu. ft. at end point conditions (epc)</td>
</tr>
<tr>
<td></td>
<td>$B_{g,W4}$</td>
<td>DMP-203 EOS Model</td>
<td>Gas volume at (apc) over gas volume at (SC) cu ft, apc/cfSC</td>
</tr>
<tr>
<td></td>
<td>$MLV_{W4,apc}$</td>
<td>DMP-203</td>
<td>Bbls at (apc)</td>
</tr>
<tr>
<td></td>
<td>$X_{w,W4,apc}$</td>
<td>WIO DMP-203</td>
<td>Water volume fraction at (apc)</td>
</tr>
<tr>
<td></td>
<td>$SF_{W4}$</td>
<td>DMP-203 EOS model</td>
<td>Bbls at (SC) over Bbls at (apc)</td>
</tr>
<tr>
<td></td>
<td>$FF_{W4}$</td>
<td>PVT analysis of Well 4 separator oil sample</td>
<td>Gas volume at (SC) over Bbls at (SC)</td>
</tr>
<tr>
<td></td>
<td>$AFUG_{W4}$</td>
<td>Attributed from DMP-004 DMP-005</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$AFLG_{W4}$</td>
<td>Attributed from DMP-007</td>
<td>Scf</td>
</tr>
<tr>
<td>Field B Well 5 Separator ($W5$)</td>
<td>$EOS,GV_{W5,epc}$</td>
<td>DMP-204 EOS Model</td>
<td>cu. ft. at end point conditions (epc)</td>
</tr>
<tr>
<td></td>
<td>$B_{g,W5}$</td>
<td>DMP-204 EOS Model</td>
<td>Gas volume at (apc) over gas volume at (SC) cu ft, apc/cfSC</td>
</tr>
<tr>
<td></td>
<td>$MLV_{W5,apc}$</td>
<td>DMP-204</td>
<td>Bbls at (apc)</td>
</tr>
<tr>
<td></td>
<td>$X_{w,W5,apc}$</td>
<td>WIO DMP-204</td>
<td>Water volume fraction at (apc)</td>
</tr>
<tr>
<td></td>
<td>$SF_{W5}$</td>
<td>DMP-204 EOS model</td>
<td>Bbls at (SC) over Bbls at (apc)</td>
</tr>
<tr>
<td></td>
<td>$FF_{W5}$</td>
<td>PVT analysis of Well 5 separator oil sample</td>
<td>Gas volume at (SC) over Bbls at (SC)</td>
</tr>
<tr>
<td></td>
<td>$AFUG_{W5}$</td>
<td>Attributed from DMP-004 DMP-005</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$AFLG_{W5}$</td>
<td>Attributed from DMP-007</td>
<td>Scf</td>
</tr>
</tbody>
</table>

**A.4.4.3.6 Determination of Theoretical Gas Energy Quantities**

Theoretical gas energy (TGE) quantities are based on the theoretical gas volume (TGV) times the mole fraction of each component (C1 thru C10+) per the theoretical gas composition (TGC), times energy content.
(EC) for each component. The summation of the energy contribution of each component establishes the energy for the stream as follows:

\[
NTGE_i = \sum(Mol\%_{i,C1-C10+} \times NTGV_i \times EC_{comp.})
\]

Where

- \(NTGE_i\) Net theoretical gas energy for separator (i)
- \(Mol\%_{i,C1-C10+}\) Mole fraction of each component
- \(NTGV_i\) Net theoretical gas volume
- \(EC_{comp.}\) Energy content of each component, C1 through C10+

The C10+ fraction component energy content is taken as equal to the energy content of Decane and condensate (liquid) quantity basis of the PSM results is provided in the same measurement units of the Oil Sales LACT (e.g. Bbls.).

A.4.4.4 Determination of Theoretical Water Quantities

Theoretical water quantities are determined either by a metered water stream quantity or a water fraction analyzer result or sample lab result applied to a metered oil stream. Analyzer results are applied to metered quantities at line (actual) conditions and lab results are applied to oil metered quantities at standard conditions.

For a three phase separator the theoretical water volume is the summation of the meter water and the water fraction volume of the oil flow.

\[
TWV_{3\,ph,i} = MWV_{i,apc} \times CTW + (MLV_{i,apc} \times X_{W,i,apc} \times CTW)
\]

EQ A- 15

Where:

- \(MWV_{i,apc}\) is referred to as the "water fraction volume"
- \(MLV_{i,apc}\) and \(X_{W,i,apc}\) are at the same p, t conditions
- \(CTW\) the correction for temperature relative to produced water

For a two phase separator the theoretical water volume is equal to the water fraction volume.

\[
TWV_{2\,ph,Sep} = MLV_{i,apc} \times X_{W,i,apc} \times CTW
\]

EQ A- 16

A.4.4.4.1 Well Test Theoretical Quantities

A.4.4.4.1.1 Theoretical quantities for Field A, Wells 1, 2, and 3 are determined by well tests using the Field A test separator measurement (DMP-201). Wells 4 and 5 both have dedicated separators and are continuously measured and therefore need no well test theoretical quantity determination.

A.4.4.4.1.2 Oil, gas, and water production quantities are calculated as a rate per time applied to well up time. Well testing procedure and calculation of quantities to standard conditions are per API MPMS Ch. 20.5. Well test results are stated at standard conditions.

A.4.4.4.1.3 Theoretical oil and gas rates are converted into theoretical volume by multiplying the gas and oil rates times the well uptime over the allocation period as follows:

\[
TGV_{Well,i} = TGVR_{Well,i} \times Uptime_{well\,i}
\]

EQ A- 17
Theoretical gas energy for well tested wells is determined as follows:

\[ TGE_{\text{Well}_i} = \sum \left( \frac{\text{Mol\%}_{\text{well}_i} \times C_{\text{C1-C10+}} \times TGV_{\text{Well}_i} \times EC_{\text{comp.}}}{\text{Well Test Time}} \right) \]

EQ A-19

The theoretical water rate (TWR) is determined by combining the metered water volume (MWV) from the water leg and water fraction (XW) percentage applied to the metered liquid volume (MLV) at the separator oil leg, over the well test time:

\[ TWR_{\text{Well}_i} = \frac{(\text{MWV}_{\text{TestSep}} \times CTL_{\text{W}}) + (\text{MLV}_{\text{TestSep}} \times XW) \times CTL_{\text{W}}}{\text{Well Test Time}} \]

EQ A-20

Where:

- \( MLV \times XW \) is referred to as the “water fraction volume”
- \( MLV \) and \( XW \) are at the same p, t conditions
- \( CTL_{\text{W}} \) is the temperature correction for water

Water rates are converted into theoretical water volume (TWV) by multiplying the water rate times the well uptime in terms of hours over the allocation period as follow:

\[ TWV_{\text{Well}_i} = TWR_{\text{Well}_i} \times \text{Uptime}_{\text{Well}_i} \]

EQ A-21

### A.4.5 Allocation Method

#### A.4.5.1 General

Tier one allocation holds whole the trucked oil from Well 6 because it is measured by the Trucked Oil LACT unit of equal uncertainty to the Oil Sales LACT. Oil allocation quantity for the Gas Production Sources (GPS) is based on the difference of Sales Oil LACT and Trucked Oil LACT accounting for both the inventory change in the DOT and WOT to Oil Sale and Trucked Oil, respectively.

Tier two allocation addresses only the mainly GPS oil, gas, and water to Field A, Well 4, and Well 5. Well six oil, gas and water volumes are predominately based on CPF values and smaller additional quantities provided by the 3rd party entities. Tier three allocation only includes wells 1, 2, and 3 as they are the only wells commingled prior to separation and use periodic well testing.

#### A.4.5.2 Oil Allocation

##### A.4.5.2.1 Tier One Oil Allocation

A.4.5.2.1.1 The basic oil measurement reference is the CPF Oil Sales LACT NSV (DMP-001) plus the inventory change in the DOT (DMP-002). GPS allocated oil volume (AOV) is based on the difference of the Oil Sales and the Trucked Oil. Also, because of the hold whole situation and the fact that the Well 6 oil volume is much greater than the GPS produced hydrocarbon liquids, the inventory change is not tracked on source by source basis.

\[ Oil Sales_{\text{CPF}} = NSV_{\text{Oil Sales LACT}} + EINV_{\text{DOT}} - BINV_{\text{DOT}} \]

EQ A-22

\[ Trucked Oil_{\text{CPF}} = NSV_{\text{Trucked Oil LACT}} + EINV_{\text{WOT}} - BINV_{\text{WOT}} \]

EQ A-23
A.4.5.2.1.2 The liquid production from the Gas Production Sources (GPS) is also metered and analyzed for water content to determine metered oil NSV at DMP-103. These quantities are used to verify the by-difference derived allocated quantities for the GPS where a variance more than 5% is a case for review as follows:

\[
\frac{NSV_{103}}{AOV_{GPS}} \geq 1.05 \ OR \ \leq 0.95,
\]

THEN: Flag_{103} = 1, ELSE: Flag_{103} = 0

\[E Q \ A- 25\]

A.4.5.2.2 Tier Two Oil Allocation

A.4.5.2.2.1 Tier two of the oil allocation allocates the GPS AOV to the GPS separators proportionally based on theoretical oil volume as determined per Section A.4.4.2.

\[AOV_{FLD_A} = \frac{TOV_{FLD_A}}{TOV_{GPS}} \times AOV_{GPS}\]

EQ A- 26

\[AOV_{W4} = \frac{TOV_{W4}}{TOV_{GPS}} \times AOV_{GPS}\]

EQ A- 27

\[AOV_{W5} = \frac{TOV_{W5}}{TOV_{GPS}} \times AOV_{GPS}\]

EQ A- 28

A.4.5.2.2.2 Also in the tier two allocation Well 6 oil allocations is finished by adding any allocated hydrocarbon liquids determined by the 3rd party gas gathering company:

\[AOV_{W6} = Trucked \ Oil_{CPF} + 3rd \ Party \ Allocated \ Liquids\]

EQ A- 29

A.4.5.2.3 Tier Three Oil Allocation

Tier three oil allocation allocated the Field A allocated oil to Wells 1, 2, and 3 per well test results.

\[AOV_{W1} = \frac{TOV_{W1}}{TOV_{GPS}} \times AOV_{FLD_A}\]

EQ A- 30

\[AOV_{W2} = \frac{TOV_{W2}}{TOV_{GPS}} \times AOV_{FLD_A}\]

EQ A- 31

\[AOV_{W3} = \frac{TOV_{W3}}{TOV_{GPS}} \times AOV_{FLD_A}\]

EQ A- 32

A.4.5.3 Gas Allocation

A.4.5.3.1 Tier One Gas Allocation

A.4.5.3.1.1 Because Well 6 oil is deemed to be gas free at the entrance to the CPF, all Sales Gas is allocated to the GPS separators. Therefore:

\[AGV_{GPS} = Gas \ Sales \ Volume_{CPF}\]

EQ A- 33

\[AGE_{GPS} = Gas \ Sales \ Energy_{CPF}\]

EQ A- 34
A.4.5.3.2 Tier Two Gas Allocation

A.4.5.3.2.1 Well 6 allocated gas volume and energy is based solely on the allocation of the 3rd party gas gathering operation. The oil tank at the well 6 location is small and the associated inventory change not considered in the allocation.

\[
AGV_{Well6} = AGV_{3rd\text{party}} \quad \text{EQ A- 37}
\]

\[
AGE_{Well6} = AGE_{3rd\text{party}} \quad \text{EQ A- 38}
\]

A.4.5.3.2.2 Fuel gas is allocated the separators based on gross theoretical gas volume (GTGV):

\[
AFuGV_{FLD A} = \frac{GTGV_{FLD A}}{\sum GTGV_{GPS}} \times AFuGV_{GPS} \quad \text{EQ A- 39}
\]

\[
AFuGV_{W4} = \frac{GTGV_{W4}}{\sum GTGV_{GPS}} \times AFuGV_{GPS} \quad \text{EQ A- 40}
\]

\[
AFuGV_{W5} = \frac{GTGV_{W5}}{\sum GTGV_{GPS}} \times AFuGV_{GPS} \quad \text{EQ A- 41}
\]

A.4.5.3.2.3 Flare gas is allocated the separators based on gross theoretical gas volume (GTGV):

\[
AFlGV_{FLD A} = \frac{GTGV_{FLD A}}{\sum GTGV_{GPS}} \times AFlGV_{GPS} \quad \text{EQ A- 42}
\]

\[
AFlGV_{W4} = \frac{GTGV_{W4}}{\sum GTGV_{GPS}} \times AFlGV_{GPS} \quad \text{EQ A- 43}
\]

\[
AFlGV_{W5} = \frac{GTGV_{W5}}{\sum GTGV_{GPS}} \times AFlGV_{GPS} \quad \text{EQ A- 44}
\]

A.4.5.3.2.4 The net theoretical gas volume (NTGV) for each source is the GTGV minus fuel and flare:

\[
NTGV_{FLD A} = NTGV_{FLD A} + AFuGV_{FLD A} + AFlGV_{FLD A} \quad \text{EQ A- 45}
\]

\[
NTGV_{W4} = NTGV_{W4} + AFuGV_{W4} + AFlGV_{W4} \quad \text{EQ A- 46}
\]

\[
NTGV_{W5} = NTGV_{W5} + AFuGV_{W5} + AFlGV_{W5} \quad \text{EQ A- 47}
\]

A.4.5.3.2.5 Tier two of the gas allocation allocates the GPS AGV to the GPS separators proportionally based on theoretical oil volume as determined per Section A.4.4.2.

\[
AGV_{FLD A} = \frac{NTGV_{FLD A}}{\sum NTGV_{GPS}} \times AGV_{GPS} \quad \text{EQ A- 48}
\]
A.4.5.3.2.6 Tier two of the gas allocation allocates the GPS AGE to the GPS separators proportionally based on theoretical oil volume as determined per Section A.4.4.2.

\[
AGV_{W4} = \frac{NTGV_{W4}}{\sum NTGV_{GPS}} \times AGV_{GPS} \quad \text{EQ A-49}
\]
\[
AGV_{W5} = \frac{NTGV_{W5}}{\sum NTGV_{GPS}} \times AGV_{GPS} \quad \text{EQ A-50}
\]

A.4.5.3.3 Tier Three Gas Allocation

A.4.5.3.3.1 Tier three gas allocation allocates the Field A allocated gas volume to Wells 1, 2, and 3 per well test results. The same process as described in tier two GPS allocation is used.

A.4.5.3.3.2 Fuel gas is allocated the wells based on gross theoretical gas volume (GTGV):

\[
AFuGV_{W1} = \frac{GTGV_{W1}}{\sum GTGV_{FLD}} \times AFuGV_{FLD} A \quad \text{EQ A-54}
\]
\[
AFuGV_{W2} = \frac{GTGV_{W2}}{\sum GTGV_{FLD}} \times AFuGV_{FLD} A \quad \text{EQ A-55}
\]
\[
AFuGV_{W3} = \frac{GTGV_{W3}}{\sum GTGV_{FLD}} \times AFuGV_{FLD} A \quad \text{EQ A-56}
\]

A.4.5.3.3.3 Flare gas is allocated wells based on gross theoretical gas volume (GTGV):

\[
AFlGV_{W1} = \frac{GTGV_{W1}}{\sum GTGV_{FLD}} \times AFlGV_{FLD} A \quad \text{EQ A-57}
\]
\[
AFlGV_{W2} = \frac{GTGV_{W2}}{\sum GTGV_{FLD}} \times AFlGV_{FLD} A \quad \text{EQ A-58}
\]
\[
AFlGV_{W3} = \frac{GTGV_{W3}}{\sum GTGV_{FLD}} \times AFlGV_{FLD} A \quad \text{EQ A-59}
\]

A.4.5.3.4 The net theoretical gas volume (NTGV) for each well is the GTGV minus fuel and flare:

\[
NTGV_{W1} = NTGV_{W1} + AFuGV_{W1} + AFlGV_{W1} \quad \text{EQ A-60}
\]
\[
NTGV_{W2} = NTGV_{W2} + AFuGV_{W2} + AFlGV_{W2} \quad \text{EQ A-61}
\]
\[
NTGV_{W3} = NTGV_{W3} + AFuGV_{W3} + AFlGV_{W3} \quad \text{EQ A-62}
\]

A.4.5.3.5 Net theoretical gas volume is used to proportion and allocate to the well level.

\[
AGV_{W1} = \frac{NTGV_{W1}}{\sum NTGV_{FLD}} \times AGV_{FLD} A \quad \text{EQ A-63}
\]
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\[
AGV_{W2} = \frac{NTGV_{W2}}{\sum NTGV_{FLD A}} \times AGV_{FLD A} \quad \text{EQ A- 64}
\]

\[
AGV_{W3} = \frac{NTGV_{W3}}{\sum NTGV_{FLD A}} \times AGV_{FLD A} \quad \text{EQ A- 65}
\]

A.4.5.3.3.6 Tier two of the gas allocation allocates the GPS AG E to the GPS separators proportionally based on theoretical oil volume as determined per Section A.4.4.2.

\[
AGE_{W1} = \frac{NTGE_{W1}}{\sum NTGE_{FLD A}} \times AGE_{FLD A} \quad \text{EQ A- 66}
\]

\[
AGE_{W2} = \frac{NTGE_{W2}}{\sum NTGE_{FLD A}} \times AGE_{FLD A} \quad \text{EQ A- 67}
\]

\[
AGE_{W3} = \frac{NTGE_{W3}}{\sum NTGE_{FLD A}} \times AGE_{FLD A} \quad \text{EQ A- 68}
\]

A.4.5.4 Water Allocation

A.4.5.4.1 Tier One Water Allocation

A.4.5.4.1.1 Well 6 is held-whole on water in as similar manner as with oil where Well 6 is assigned the water volume according to the Trucked Oil LACT measurements and GPS water is determined by difference to the CPF total water volume. Well 6 is allocated the water quantity determined by the Trucked Oil LACT water fraction results applied to the Trucked Oil Gross Standard Volume (GSV) at DMP-101.

\[
AWV_{Trk Oil} = GSV_{Trk Oil} \times (1 - X_{W Trk Oil}) \quad \text{EQ A- 69}
\]

A.4.5.4.1.2 The total water at the CPF is the summation of the metered water volume at DMP-007, the inventory change in the water tank (DMP-008) and the Sales Oil water fraction applied to the GSV (DMP-001).

\[
TotalWater_{CPF} = MVW_{007} + ENV_{008} - BINV_{008} + \left[ GSV_{Sales} \times (1 - X_{W Sales}) \right] \quad \text{EQ A- 70}
\]

A.4.5.4.1.3 The GPS allocated water is difference between the CPF total water and the trucked oil allocated water.

\[
AWV_{GPS} = TotalWater_{CPF} - AWV_{Trk Oil} \quad \text{EQ A- 71}
\]

A.4.5.4.2 Tier Two Water Allocation

A.4.5.4.2.1 Well 6 allocated water volume is the sum of the trucked oil allocated water volume at the CPF and the metered water volume at the well 6 location (DMP-206). The change in inventory in the water tank at the well 6 location is not used in the allocation.

\[
AWV_{W6} = AWV_{Trk Oil} + MWV_{DMP-206} \quad \text{EQ A- 72}
\]

A.4.5.4.2.2 For the GPS the allocated water volume is based on theoretical water volume for each source.

\[
AWV_{FLD A} = \frac{TWV_{FLD A}}{\sum TWV_{GPS}} \times AWV_{GPS} \quad \text{EQ A- 73}
\]
A.4.5.4.3 Tier Three Water Allocation

The tier three water allocation is performed similarly based on theoretical water volumes determined by well tests.

\[
AWV_{W1} = \frac{TWV_{W1}}{\sum TWV_{FLD_A}} \times AWV_{FLD_A}
\]  
EQ A- 76

\[
AWV_{W2} = \frac{TWV_{W2}}{\sum TWV_{FLD_A}} \times AWV_{FLD_A}
\]  
EQ A- 77

\[
AWV_{W3} = \frac{TWV_{W3}}{\sum TWV_{FLD_A}} \times AWV_{FLD_A}
\]  
EQ A- 78
Annex B
(informative)

Example PMAS for an Offshore Field

The following examples are merely examples for illustration purposes only. They are 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.

B.1 Offshore Scenario Description

For the purpose of illustrating the PMAS development business process in the normative section of this document, an offshore production scenario has been construed. Annex B is based on this fictitious scenario, described below.

The scenario consists of seven wells that produce onto an offshore production facility. A graphical depiction of the production scenario is provided in Figure B.13.

There are four entities with ownership interest in the scenario. These are companies Alpha, Bravo, Charlie and Delta. Company Alpha (OPERATOR) is the operator on record. The production and facility ownership amongst the various parties are given in Table B.11. All wells produce from leases with identical royalty rates.

<table>
<thead>
<tr>
<th>Wells</th>
<th>Alpha Ownership</th>
<th>Bravo Ownership</th>
<th>Charlie Ownership</th>
<th>Delta Ownership</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>60%</td>
<td>30%</td>
<td>10%</td>
<td>-</td>
</tr>
<tr>
<td>2</td>
<td>60%</td>
<td>30%</td>
<td>10%</td>
<td>-</td>
</tr>
<tr>
<td>3</td>
<td>60%</td>
<td>30%</td>
<td>10%</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>70%</td>
<td>-</td>
<td>10%</td>
<td>30%</td>
</tr>
<tr>
<td>5</td>
<td>50%</td>
<td>50%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>6</td>
<td>60%</td>
<td>30%</td>
<td>10%</td>
<td>-</td>
</tr>
<tr>
<td>7</td>
<td>60%</td>
<td>30%</td>
<td>10%</td>
<td>-</td>
</tr>
<tr>
<td>Hub</td>
<td>60%</td>
<td>30%</td>
<td>10%</td>
<td>-</td>
</tr>
</tbody>
</table>

Wells 1-3 comprise Lease Unit A, wells 4 and 5 produce from Lease Unit B, and wells 6 and 7 from Lease Unit C. Wells from Lease Units A and C have identical ownership interests. Lease Unit B wells have ownership disparity.

Wells 1-3 are commingled into a two-phase IP Separator equipped with gas meter, liquid meter and online water cut analyzer. Well 4 is metered separately and continuously with a two-phase HP Separator equipped with gas meter, liquid meter and online water cut analyzer. Well 5 is commingled with the HP separator liquid outflow upstream of a three-phase LP separator equipped with gas meter, oil meter, water meter and online water cut analyzer. Wells 6 and 7 are commingled upstream of a two-phase LLP Separator equipped with gas meter, liquid meter and online water cut analyzer.

A two-phase test separator equipped with gas meter, liquid meter and online water cut analyzer allows any of the wells to be tested periodically. Wells 1-3 and 5-7 are routed to the test separator for periodic well testing to establish well rates for allocation purposes. The separated gas and liquids from the test separator are routed back to the applicable separator during well testing. Well 4 rate is based on dedicated and continuous measurement.
Gas outflow from the IP, LP and LLP separators are commingled with FWKO, WOT and DOT gas streams and routed to compression. The compressed gas is commingled with the HP separator gas stream and routed to dew pointing unit. Sales gas is metered via the export gas metering skid.

Pre-sales gas offtake downstream of the glycol contactor provides lift gas for Wells 6 and 7 as well as fuel for the facility. Lift gas returns to the LLP separator. Buy-back gas is procured on a need basis.

Oil and water streams are processed in the facility, routing stabilized oil to the dry oil tank. The oil sales measurement occurs downstream of the dry oil tank via the LACT unit. Buy-back oil offtake is located downstream of the LACT unit and is routed back into the DOT. DOT oil is circulated under a no-sales run ticket using the pigging meter and associated shipment pump for hot oiling during start-up and shut-down operations.

Separated water from the FWKO and LP separator are routed to hydrocyclones prior to discharge overboard. Overboard water is metered downstream of the hydrocyclones.

Other general details include:

- a) All wells produce very similar black oil fluids
- b) Wells 4 and 5 are satellite well tie-backs
- c) Well 4 has a much higher production rate than Well 5
- d) There is oil inventory at the DOT

**B.2 Identify PMAS Requirements**

**B.2.1 Roles and Responsibilities**

OPERATOR is responsible for the development, implementation, operation, performance management and maintenance of the PMAS. Table B.12 provides a list of OPERATOR functional roles and their responsibilities.

<table>
<thead>
<tr>
<th>Role</th>
<th>Responsibility</th>
</tr>
</thead>
</table>
| Operations | • Production operation systems and data quality maintenance and assurance  
• Process and measurement equipment reliability and maintenance  
• Development of standard operating procedures including sampling, meter swaps, meter configuration and well testing,  
• PMAS related work scheduling and operational coordination  
• Wells operations and data recording  
• Out-of-tolerance PMAS performance investigation, remediation and reporting  
• LACT run tickets and gas pipeline statements  
• Performs the monthly allocation calculations and reporting |
| Finance | • Production reporting to operations, marketing, finance, subsurface, regulatory agencies and external partners  
• Daily and monthly volumetric data to feed production allocation |
<table>
<thead>
<tr>
<th>Role</th>
<th>Responsibility</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Production variance analysis and reporting</td>
</tr>
<tr>
<td></td>
<td>• Performs allocation calculations, data analytics, detection and reporting of out-of-tolerance performance</td>
</tr>
<tr>
<td></td>
<td>• Controls documentation maintenance (Sarbanes-Oxley)</td>
</tr>
<tr>
<td>Reservoir and Production Management</td>
<td>• Establishes well testing program and well test acceptance criteria</td>
</tr>
<tr>
<td></td>
<td>• Develops well decline curves</td>
</tr>
<tr>
<td></td>
<td>• Development and maintenance of reservoir model for forecasting and reserves management</td>
</tr>
<tr>
<td>Commercial/Auditing</td>
<td>• Verification of compliance with regulatory and commercial requirements</td>
</tr>
<tr>
<td></td>
<td>• Performance of measurement and cost allocation audits</td>
</tr>
<tr>
<td>Marketing</td>
<td>• Coordinate pipeline nominations</td>
</tr>
<tr>
<td></td>
<td>• Supports gas balancing</td>
</tr>
</tbody>
</table>
Figure B.13 Offshore Scenario MAPFD
B.2.2  Governmental and Commercial Requirements

B.2.2.1  Governmental Requirements

The regulatory body approved Surface Commingling Permit stipulates the following requirements that are relevant to allocation:

a) Designated Measurement Points (DMP) are per the Measurement and Allocation Process Flow Diagram (MAPDF) shown in Figure B.13.

b) Well rate determination

   i. Periodic well testing will be utilized for all wells, except Well 4, to determine well rates for allocation purposes
   ii. Well tests will be conducted every 60 days, not to exceed 90 days
   iii. Well 4 rate will be based on the prorated cumulative volumes from continuous measurement
   iv. Virtual flow metering will be utilized on all wells to allocate daily sales oil and gas volumes

c) Oil, gas and water will be allocated proportionally on a volume basis

d) Royalty for the liquid hydrocarbons produced from the offshore facility will be based on the volume and volume-weighted average gravity as determined by the LACT unit, minus any volume of buyback oil measured by the buy-back oil meter DMP # 202.

e) Allocation of liquid hydrocarbons measured by the LACT meters to the individual lease units/wells will be as follows:

   i. Lease Unit A liquid hydrocarbon allocation will be based on volume measured by the oil allocation meter DMP #112, located downstream of the IP separator, converted to theoretical oil volume, plus the theoretical liquid dropout volume determined at the gas allocation metering point DMP #102, located downstream of the same separator. Further allocation of the liquid hydrocarbon to Wells 1, 2 and 3 will be based on well tests.

   ii. Lease Unit B liquid hydrocarbon allocation will be based on volume measured by the oil allocation meter DMP #114, located downstream of the LP separator, converted to theoretical oil volume, plus the theoretical liquid dropout volume determined at the gas metering points DMP #103 and DMP #104, located downstream of the HP and LP separators, respectively. Further allocation of Lease Unit B liquid hydrocarbon will be based on the Well 5 theoretical oil volume based on well test and Well 4 oil volume measured by DMP # 113, located downstream of the HP separator, converted to theoretical oil volume, plus theoretical liquid dropout volume determined at the gas metering point DMP #103, located downstream of the same separator.

   iii. Lease Unit C liquid hydrocarbon allocation will be based on volume measured by the oil allocation meter DMP #115, located downstream of the LLP separator, converted to theoretical oil volume, plus the theoretical liquid dropout volume determined at the gas meter, DMP #105 metering point located downstream of the same separator, minus the circulated oil volume measured by DMP #203. Further allocation of the net liquid hydrocarbon to Wells 6 and 7 will be based on well tests.

f) Royalty for the gas produced from the offshore facility will be based on the volume determined by the gas export metering point, minus any volume of buyback gas measured by the buy-back gas meter DMP #302.

g) Allocation of gas volume measured by the export gas meters to the individual lease units/wells well be as follows:

   i. Lease Unit A gas allocation will be based on the gas volume determined at the gas allocation meter DMP #102, located downstream of the IP separator, converted to theoretical gas volume, plus the theoretical flash gas volume determined at the liquid hydrocarbon allocation meter DMP
#112, located downstream of the same separator, minus fuel and flare volumes attributable to this unit. Further allocation of this gas volume to Wells 1, 2 and 3 will be based on well tests.

ii. Lease Unit B gas allocation will be based on the sum of the gas volumes determined at the gas allocation meters DMP #103 and DMP #104, located downstream of the HP and LP separators, converted to theoretical gas volume, plus the theoretical flash gas volume determined at the liquid hydrocarbon allocation meter DMP #114 located downstream of the LP separator, minus fuel and flare volumes attributable to this unit. Further allocation of Lease Unit B gas volume will be based on the Well 5 theoretical gas volume based on well test and Well 4 gas volume measured by the gas allocation meter DMP #103 located downstream of the HP separator, converted to theoretical gas volume, plus the theoretical flash gas volume determined at the metering point DMP #113, located downstream of the same separator.

iii. Lease Unit C gas allocation will be based on the gas volume determined at the gas allocation metering point located downstream of the LLP separator, converted to theoretical gas volume, plus the theoretical flash gas volume determined at the liquid hydrocarbon metering point located downstream of the same separator, minus fuel and flare volumes attributable to this unit, minus the circulated gas lift volume measured by DMP #303. Further allocation of the net gas volume to Wells 6 and 7 will be based on well tests.

B.2.2.2 Commercial Requirements

The Production Handling Agreement (PHA), entered into and agreed by all parties, stipulates the following requirements that are relevant to production allocation:

a) All production shall be sampled, metered, allocated and reported on a monthly basis, in accordance with the provisions of the PHA Section on Measurement and Allocation (typically under Article 7 - Operations; Measurement and Allocation; Detailed Measurement & Allocation Procedures are typically found in the EXHIBITS attached to the PHA), subject to and in accordance with the regulatory body approved Surface Commingling Permit

b) Operator will enter into separate agreements with oil and gas gathering and transportation entities

c) Well tests will be conducted for all wells per the Regulatory requirements of 60 days, NTE 90 days between tests, except for Well 5 which will be tested every 30 days

d) Periodic well testing will be conducted in accordance with API MPMS 20.5

e) Sales oil, sales gas and overboard water allocation at the lease level will be performed on a volume basis, prorated by the source point allocated theoretical volume relative to the total component theoretical volume from all sources, adjusted for fuel and flare

f) Lease allocated oil, gas and water volumes will be allocated to the well level based on well rates determined from periodic well testing or continuous measurement

g) Lease B well level sales gas allocation will be prorated based on theoretical gas basis excluding fuel and flare

h) Virtual flow metering will be utilized on all wells to allocate daily sales oil and gas volumes, for input as oil and gas production estimates into the Daily Production Report

i) Daily oil and gas production estimates will be used for submission of oil and gas nominations to export pipeline operators

j) Compression fuel gas consumption will be allocated to the IP, LP and LLP separators based on the theoretical gas volume allocated to each separator

k) Flare gas volume will be metered at the high pressure and low pressure flare header DMPs. Any purposely flared gas from a specific separator that is flared subsequent to allocation measurement will be assigned only to such relevant separator allocated flare volume. All other flare gas will be allocated on volume basis for each separator. Sales gas quality will be used to represent flare gas quality

l) Material balance factors
i. The balance factor for oil, gas and water volumes are calculated as follows:

\[
\text{Material Balance Factor} = \frac{\text{Reference Volume} - \text{Theoretical Volume}}{\text{Reference Volume}} \times 100\%
\]

*Reference Volume* is oil or gas sales volume or overboard water volume for the allocation period.

ii. For any given month, the balance between (1) Facility Theoretical Oil Volume (FTOV) and Oil Sales Meter Volume, (2) Facility Theoretical Gas Volume (FTGV) and Gas Sales Meter Volume, or (3) overboard water meter volume and the sum of production separator water metered volume not exceed ±5 % (per PHA).

iii. If for any two (2) consecutive months, or for three (3) months out of any twelve (12) consecutive months, the value for one (1) of the balance factors exceeds ±5 %, then OPERATOR will take corrective action to resolve the imbalance.

m) Other requirements include:

i. The total water volume measured by the overboard water meter, plus the water determined by the S&W and LACT meter export oil volume, will be allocated to the separators based on the water volumes determined by the water meter or net oil analyzer

ii. Liquid allocation meters will be swapped and proved every 60 days, in accordance with API MPMS Ch. 20.2

iii. Gas allocation meter will be proved/inspected every 60 days in accordance with API MPMS Ch. 20.2

iv. Composite samples will be obtained on a monthly basis for each oil stream to determine shrinkage factors and flash gas volume factors

v. Composite samples will be obtained on a monthly basis for each gas stream to determine gas volume factors and condensate-gas ratios

vi. Water volume factors can be determined analytically from produced water sample or calculated per Annex F of API MPMS Ch. 20.5

**B.2.3 Reservoir/Production Management Requirements**

Beyond oil, gas and produced water volumes, reservoir and production management requires production rate along with pressure and temperature data, e.g. at bottomhole and wellhead locations.

Reservoir / Production management requirements for the PMAS are as follows:

a) Well rate determination test results

b) Monthly well produced accumulated volumes

c) Monthly well average rates

d) Estimated daily well produced gross volumes

**B.2.4 Acceptance Criteria**

The performance evaluation of the offshore PMAS will be based on the criteria and their acceptable thresholds listed in Table B.13.
Table B.13 Acceptance Criteria

<table>
<thead>
<tr>
<th>Acceptance Criteria</th>
<th>Acceptance Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tier 1 lease level oil, gas and water balance</td>
<td>±5%</td>
</tr>
<tr>
<td>Tier 2 well level oil, gas and water balance</td>
<td>±8%</td>
</tr>
<tr>
<td>Liquid allocation meter</td>
<td></td>
</tr>
<tr>
<td>Proving repeatability (5 out of 6 consecutive runs)</td>
<td>±0.5%</td>
</tr>
<tr>
<td>Meter Factor variance between proves</td>
<td>±1%</td>
</tr>
<tr>
<td>Liquid allocation meter</td>
<td></td>
</tr>
<tr>
<td>Proving repeatability (5 out of 6 consecutive runs)</td>
<td>±0.5%</td>
</tr>
<tr>
<td>Meter Factor variance between proves</td>
<td>±1%</td>
</tr>
<tr>
<td>Water cut analyzer versus shakeout comparison</td>
<td></td>
</tr>
<tr>
<td>0-20% Water cut</td>
<td>±1% abs</td>
</tr>
<tr>
<td>20-60% Water cut</td>
<td>±2% abs</td>
</tr>
<tr>
<td>As-found variation on differential and static pressure transmitters</td>
<td>±0.5%</td>
</tr>
<tr>
<td>As-found variation on temperature transmitter</td>
<td>±0.5%</td>
</tr>
<tr>
<td>Oil and gas sample bottle pressure heated to separator temperature</td>
<td>±10 psi</td>
</tr>
<tr>
<td>Oil shrinkage and flash gas factors</td>
<td>Within est. min/max</td>
</tr>
<tr>
<td>Gas volume factor and CGR</td>
<td>Within est. min/max</td>
</tr>
</tbody>
</table>

B.3 Select Basis of Allocation

B.3.1 General

The following section describes the basis of allocation for the offshore production scenario, per the PMAS requirements established in Section B.2. It includes a description of (1) fluids to allocate, (2) allocation period, (3) customary units, and (4) material balance.

B.3.2 Fluids to Allocate

The following components of the offshore production scenario will be allocated to the lease unit and well levels:

a) Sales oil and gas volumes
b) Overboard water volume
c) Fuel gas and flare gas volumes

d) Oil and gas sample bottle pressure heated to separator temperature ±10 psi

B.3.3 Frequency of Allocation

The allocation frequency shall be monthly for PMAS reporting purposes. In addition, daily allocation of the export oil and gas volumes to the well level will be estimated using virtual flow metering for operation, finance, commercial, and marketing purposes.

B.3.4 Engineering Units and Physical Constants

The following customary units of measure will be used in this example:

a) Oil volume at actual conditions: bbl
b) Oil volume at standard conditions: stb
c) Gas volume at actual conditions: mcf
d) Gas volume at standard conditions: mscf
e) Temperature: °F
f) Pressure: psia

g) Standard Conditions: 14.696 psia, 60 °F

h) For gas: 6,000 scf = 1 BOE

i) Pure component physical properties: GPA 2145

B.3.5 Material Balance

B.3.5.1 Allocation Basis Description

Figure B.14 depicts the material balance scheme for the offshore production scenario. Measurement points are shown in the “M” boxes in the diagram. Material balance on a volume basis will be employed to allocate the outflow quantities including sales oil, sales gas and overboard water volumes to the lease units and onto the respective source wells. In addition, consumed quantities including fuel and flare gas will be allocated either proportionately to all sources or directly to their respective source points.

Inflow quantities include oil, gas and water from 7 wells, plus buy-back quantities of oil and gas. The material balance will account for recycle streams of oil and gas and changes in accumulated oil inventory in the dry oil tank.

The offshore scenario involves a multi-tiered allocation process. The first tier sales oil allocation involves the commingled streams at the IP, LP and LLP separators. The sales oil volume is proportionately allocated to the oil allocation metering points for each respective separator. The allocated oil volume to the IP separator is the basis for the second oil tier allocation to Wells 1-3 respectively, via well testing. The allocated oil volume to the LLP separator is the basis for the second tier oil allocation to Wells 6 and 7 respectively, via well testing.

A high pressure, high rate Well 4 flows separately into the intermediate HP separator where oil and gas outflows are metered continuously. The HP separator oil outflow commingles with Well 5 production and flows into the LP separator where oil and gas are metered. In this well alignment and process configuration, the allocated oil volume at the LP separator is the basis for the second tier allocation to Wells 4 and 5.

Allocation of this oil will be based on the Well 5 allocated oil volume based on well test and Well 4 oil volume measured by DMP # 113, located downstream of the HP separator, converted to theoretical oil volume, plus
theoretical liquid dropout volume determined at the gas metering point DMP #103, located downstream of the same separator

The first tier sales gas volume allocation involves the commingled streams at the HP, IP, LP and LLP separators. The sales gas volume is proportionately allocated to gas allocation metering points at each respective separator. The allocated gas volumes at the IP and LLP separators are the bases for the second gas tier allocation to Wells 1-3 and Wells 6 and 7, respectively, via well testing.

The allocated gas volume to the HP and LP separators are the bases for the second tier gas allocation to Wells 4 and 5. Allocation of this gas volume will be based on Well 5 allocated gas volume based on Well test and Well 4 gas volume measured at DMP #103, converted to theoretical gas volume, plus the theoretical flash gas volume determined at the meter DMP #113.

For the produced water, the first tier allocation of the overboard water volume is to the water meter or net oil analyser at the HP, IP, LP and LLP separators. The allocated water volumes at the IP and LLP separators are the bases for the second tier allocation to Wells 1-3 and Wells 6 and 7 respectively, via well testing.

The allocated water volume to the LP separator will be the basis for the second tier allocation to Wells 4 and 5, based on Well 5 well test allocated water and Well 4 theoretical water measured by the net oil analyser at DMP #113 downstream of the HP separator.

**B.3.5.2 Inflow Quantities**

The inflow streams for the offshore example are:

a) Commingled stream of Wells 1, 2, and 3 (IP separator inlet streams)

b) Commingled stream of Wells 4 and 5 (LP separator inlet stream)

c) Commingled stream of Wells 6 and 7 (LLP separator inlet streams)

d) Buy back oil

e) Buy back gas

f) Gas lift streams at Wells 6 and 7

g) Hot oil circulation stream at Wells 6 and 7

**B.3.5.3 Outflow Quantities**

The outflow streams for the offshore example are:

a) Oil sales stream at LACT

b) Gas sales stream

c) Overboard water

d) Gas lift recycle at LLP separator

e) Hot oil recycle at LLP separator

**B.3.5.4 Consumed Quantities**

The consumed streams for the offshore example are:

a) HP flare

b) LP flare

c) Vent gas
B.3.5.5 Accumulated Quantities
   a) Dry oil tank

B.4 Allocation Process Definition

B.4.1 General
This section provides details of the offshore allocation process per the allocation basis defined in Section B.3. Included are the following:
   a) Delineation of the allocation tiers
   b) Identification of the process inputs and outputs
   c) Detailed equations for theoretical quantities determination
   d) Determination method for the allocated quantities

B.4.2 Allocation Process Considerations

B.4.2.1 Fluid Similarity
For the purposes of this worked example, the offshore reservoir fluid sources are all black oil systems. The fluid property ranges for the source fluids are listed in Table B.14.

<table>
<thead>
<tr>
<th>FLUID PROPERTY</th>
<th>VALUE RANGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Fluid</td>
<td></td>
</tr>
<tr>
<td>API Gravity</td>
<td>32-36</td>
</tr>
<tr>
<td>GOR (scf/stb)</td>
<td>1,522-2,000</td>
</tr>
<tr>
<td>Separator Oil</td>
<td></td>
</tr>
<tr>
<td>Shrinkage Factor</td>
<td>0.871-0.916</td>
</tr>
<tr>
<td>C7+ fraction (mole %)</td>
<td>59-67</td>
</tr>
<tr>
<td>GOR (scf/stb)</td>
<td>184-227</td>
</tr>
<tr>
<td>Separator Gas</td>
<td></td>
</tr>
<tr>
<td>C1 content (mole %)</td>
<td>87-93</td>
</tr>
<tr>
<td>C7+ fraction (mole %)</td>
<td>0.075-0.128</td>
</tr>
<tr>
<td>Gross Heating Value (Btu/scf)</td>
<td>1,110-1,165</td>
</tr>
</tbody>
</table>

B.4.2.2 Bias
The potential sources of bias in the offshore example are as follows:

B.4.2.2.1 Liquid quantities determination
a) Volume change of mixing between black oil and potential liquid dropout from separator gas
b) Assumption of gas being saturated with water vapor
B.4.2.2.2 Gas quantities determination

a) Assumption of gas being saturated with water vapor

b) Lease B well level sales gas allocation (due to impact of ownership disparity on fuel/flare gas per well)

B.4.2.3 Continuous vs Periodic Measurement

Lease Unit B has two production wells, Wells 4 and 5. The wells have ownership disparity as well as large difference in production rates. Well 4 oil production rate is about 3 times that of Well 5. The Well 4 water cut is about 3% compared to Well 5 with about 15%. Well 4 production is measured continuously via the dedicated HP separator. The HP separator liquid outlet is then commingled with Well 5 production upstream of the LP separator where the commingled stream is measured continuously. Well 5 production volume for an allocation period is based on periodic well test while Well 4 is based on continuous measurement.

The continuous measurement of large production versus periodic well rate determination of a much smaller production creates significant risk for Well 5. This could be mitigated by more frequent well testing coupled with the use of decline curves to potentially lower the uncertainty of the theoretical quantity determination for Well 5.

In this worked example, Well 5 will be tested at twice the regulatory requirement from 60-day to a 30-day interval. This is reflected in the commercial requirements.

B.4.2.4 Gas Volume Allocation Basis

The volume based allocation basis for the sales gas quantities are justified in this scenario due to:

a) Highly similar properties of source reservoir fluid

b) Separator gas energy content maximum difference is less than 5%

c) There is no royalty rate difference between the leases

B.4.3 Offshore Scenario Allocation Tiers

The offshore example details a two-tier allocation system. Tier 1 allocates sales oil and gas, and overboard water to the lease unit level. Tier 2 allocates the lease level allocated volumes to the well level. Figure B.15 shows the two-tier allocation system flow diagram for the offshore example.

The annotations at the bottom of each box show the location of the information in the document. For example, Tier I theoretical oil volume calculation equations are detailed in Section A.4.4.2. The detailed input for the theoretical oil volume calculations are listed in Table A.8. The allocation of the sales oil volume is given in Section B.4.5.1.1. The Tier 1 oil allocation is input to the Tier 2 well level oil allocation, and the calculations are detailed in Section B.4.5.2.2.

The Tier 1 and Tier 2 inputs and detailed equations for the sales gas and overboard water are annotated accordingly.
**B.4.4 Equations for Theoretical Quantity Determination**

**B.4.4.1 Determination of Theoretical Oil Quantities**

The theoretical oil volume for each lease is the basis for the Tier 1 allocation of the sales oil volume to the lease level.

The lease level gross theoretical oil volume consists of two sources:

- a) Separator liquid outlet, corrected for S&W and shrinkage, and
- b) Theoretical liquid dropout from the separator gas outlet

Adjustment for applicable circulated oil and changes in inventory yields the lease level net theoretical oil volume. Lease Unit \( j \) net theoretical oil quantity, determined at inlet separator \( i \), is as follows:

\[
STOV_i = MLVi \times (1 - X_{wi,i}) \times SF_i + MGV_i \times (1 - X_{wg,i}) \times \frac{1}{B_{g,i}} \times r_{s,i} - CO_i + \Delta Inv_i
\]

(B.1)

Where:

- \( STOV_i \) net theoretical oil volume at separator \( i \), stb
- \( MLV_i \) measured liquid volume at separator \( i \), bbl separator conditions
- \( X_{wi,i} \) water cut of separator \( i \) liquid outlet from the online analyser, at separator conditions
$SF_i$ separator $i$ oil shrinkage factor, stb/sep bbl

$MGV_i$ measured gas volume at separator $i$, at mcf separator conditions

$X_{wg,i}$ water volume fraction in the gas, at separator conditions

$B_{g,i}$ gas volume factor, sep cf/scf

$rs,i$ condensate-gas ratio of the separator gas, stb/scf

$CO_i$ circulated oil volume, stb

$\Delta Inv_i$ change in inventory associated with separator $i$, stb

Equation (B.1) is combination of Equations (10) and (11) in Section 7.5.2 of the normative part of the document. Table A.8 lists the input data, source and unit for the theoretical oil volume calculation for each of the leases.

Table B.15 List of Input Data and Source to Calculate Lease Theoretical Oil Volume

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Source</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Lease Unit A</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>IP Separator</strong></td>
<td>$MLV_{IP}$</td>
<td>DMP #112</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>$X_{w,IP}$</td>
<td>AO #112</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{IP}$</td>
<td>PVT analysis of IP separator oil sample</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$MGV_{IP}$</td>
<td>DMP #102</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td></td>
<td>$X_{wg,IP}$</td>
<td>Calculated from Eqn B.7</td>
<td>water volume fraction, separator gas condition</td>
</tr>
<tr>
<td></td>
<td>$B_{g,IP}$</td>
<td>PVT analysis of IP separator gas sample</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>$rs,IP$</td>
<td>EOS calculated using IP separator gas composition</td>
<td>stb/scf</td>
</tr>
<tr>
<td></td>
<td>$CO_{IP}$</td>
<td>N/A</td>
<td>stb</td>
</tr>
<tr>
<td></td>
<td>$\Delta Inv_{IP}$</td>
<td>N/A</td>
<td>stb</td>
</tr>
<tr>
<td><strong>Lease Unit B</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>HP and LP Separators</strong></td>
<td>$MLV_{LP}$</td>
<td>DMP #114</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>$X_{w,LP}$</td>
<td>AO #114</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{LP}$</td>
<td>PVT analysis of LP separator oil sample</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$MGV_{HP}$ and $MGV_{LP}$</td>
<td>DMP #103 and DMP #104</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td></td>
<td>$X_{wg,HP}$ and $X_{wg,LP}$</td>
<td>Calculated from Eqn B.7</td>
<td>water volume fraction, separator gas condition</td>
</tr>
</tbody>
</table>
Lease Unit/Separator | Input Data | Source | Unit
---|---|---|---
| $B_{g,HP}$ and $B_{g,LP}$ | PVT analysis of HP and LP separator gas samples | separator cu ft/scf |
| $r_{s,HP}$ and $r_{s,LP}$ | EOS calculated using HP and LP separator gas composition | stb/scf |
| CO$_{LP}$ | N/A | stb |
| $\Delta lnV_{LP}$ | N/A | stb |

Lease Unit C
LLP Separator

| | | | |
| MLV$_{LLP}$ | DMP #115 | separator bbl |
| $X_{w,LLP}$ | AO #115 | water cut, bbl/bbl |
| SF$_{LLP}$ | PVT analysis of LLP separator oil sample | stb/separator bbl |
| MGV$_{LLP}$ | DMP #105 | cu. ft. separator condition |
| $X_{w,g,LLP}$ | Calculated from Eqn B.7 | water volume fraction, separator gas condition |
| $B_{g,LLP}$ | PVT analysis LLP separator gas sample | separator cu ft/scf |
| $r_{s,LLP}$ | EOS calculated using LLP separator gas composition | stb/scf |
| CO$_{LP}$ | DMP #203 | stb |
| $\Delta lnV_{LLP}$ | N/A | Stb |

B.4.4.2 Determination of Theoretical Gas Quantities

The theoretical gas for each lease is the basis for the Tier 1 allocation of the sales gas volume to the lease level. The lease level gross theoretical gas volume consists of two sources:

a) Separator gas outlet, corrected for moisture and volume change from separator to standard conditions accounting for phase change, and

b) Theoretical flash gas from the separator liquid outlet

Adjustment for applicable fuel, flare and circulated gas yields the lease level net theoretical gas volume.

Lease Unit $j$ net theoretical gas quantity, determined at inlet separator $i$, is as follows:

$$STG_{V_i} = MGV_i \times (1 - X_{w,g,i}) \times \frac{1}{B_{g,i}} + MLV_i \times (1 - X_{w,i}) \times SF_i \times FF_i - AFLG_i - AFUG_i - CG_i$$  \hspace{1cm} (B.2)
Where:

- \( STGV_i \) net theoretical gas volume at separator \( i \), scf
- \( MGV_i \) measured gas volume at separator \( i \), cf separator conditions
- \( X_{wg,i} \) water volume fraction in the gas, separator conditions
- \( B_{g,i} \) gas volume factor, sep cf/scf
- \( MLV_i \) measured liquid volume at separator \( i \), bbl separator conditions
- \( X_{w,i} \) water cut of separator \( i \) liquid outlet from the online analyser, separator conditions
- \( SF_i \) separator \( i \) oil shrinkage factor, stb/separator oil bbl
- \( FF_i \) flash gas factor, scf evolved gas/ separator oil stb
- \( AFLG_i \) separator \( i \) allocated flare gas volume, scf
- \( AFUG_i \) separator \( i \) allocated fuel gas volume, scf
- \( CG_i \) circulated gas volume, scf

Equation (B.2) is combination of Equations (13), (14) and (18) in Section 7.5.3 of the normative part of the document. Table B.16 lists the input data, source and unit for the theoretical gas volume calculation for each of the leases.

**Table B.16 List of Input Data and Source to Calculate Lease Theoretical Gas Volume**

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Source</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>( MGV_{IP} )</td>
<td>DMP #102</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td>Lease Unit A</td>
<td>( X_{wg,IP} )</td>
<td>Calculated from Eqn B.7</td>
<td>water volume fraction, separator condition</td>
</tr>
<tr>
<td>IP Separator</td>
<td>( B_{g,IP} )</td>
<td>PVT analysis of IP separator gas sample</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>( MLV_{IP} )</td>
<td>DMP #112</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>( X_{w,IP} )</td>
<td>AO #112</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>( SF_{IP} )</td>
<td>PVT analysis of IP separator oil sample</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>( FF_{IP} )</td>
<td>PVT analysis of IP separator oil sample</td>
<td>scf/stb</td>
</tr>
<tr>
<td></td>
<td>( AFL_{IP} )</td>
<td>Attributed from DMP #141 and DMP #142</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>( AFU_{IP} )</td>
<td>Attributed from DMP #304 and DMP #305</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>( CG_{IP} )</td>
<td>N/A</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>( MGV_{HP} ) and ( MGV_{LP} )</td>
<td>DMP #103 and DMP #104</td>
<td>cu. ft. separator cond</td>
</tr>
<tr>
<td>Lease Unit/Separator</td>
<td>Input Data</td>
<td>Source</td>
<td>Unit</td>
</tr>
<tr>
<td>----------------------</td>
<td>------------</td>
<td>--------</td>
<td>------</td>
</tr>
<tr>
<td>HP and LP Separators</td>
<td>$X_{wg,HP}$ and $X_{wg,LP}$</td>
<td>Calculated from Eqn B.7</td>
<td>water volume fraction, separator gas condition</td>
</tr>
<tr>
<td></td>
<td>$B_{g,HP}$ and $B_{g,LP}$</td>
<td>PVT analysis of HP and LP separator gas samples</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>$MLV_{LP}$</td>
<td>DMP #114</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>$X_{w,IP}$</td>
<td>AO #114</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{IP}$</td>
<td>PVT analysis of IP separator oil sample</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$FF_{IP}$</td>
<td>PVT analysis of IP separator oil sample</td>
<td>scf/stb</td>
</tr>
<tr>
<td></td>
<td>$AFL_{HP}$ and $AFL_{LP}$</td>
<td>Attributed from DMP #141 and DMP #142</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$AFU_{LP}$</td>
<td>Attributed from DMP #304 and DMP #305</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$CG_{HP}$</td>
<td>N/A</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$CG_{LP}$</td>
<td>N/A</td>
<td>Scf</td>
</tr>
<tr>
<td>Lease Unit C LLP Separator</td>
<td>$MGV_{LLP}$</td>
<td>DMP #105</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td></td>
<td>$X_{wg,LLP}$</td>
<td>Calculated from Eqn B.7</td>
<td>water volume fraction, separator condition</td>
</tr>
<tr>
<td></td>
<td>$B_{g,LLP}$</td>
<td>PVT analysis LLP separator gas sample</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>$MLV_{LLP}$</td>
<td>DMP #115</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>$X_{w,LLP}$</td>
<td>AO #115</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{LLP}$</td>
<td>PVT analysis of LLP separator oil sample</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$FF_{LLP}$</td>
<td>PVT analysis of LLP separator oil sample</td>
<td>scf/stb</td>
</tr>
<tr>
<td></td>
<td>$AFL_{LLP}$</td>
<td>Attributed from DMP #141 and DMP #142</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$AFU_{LLP}$</td>
<td>Attributed from DMP #304 and DMP #305</td>
<td>Scf</td>
</tr>
<tr>
<td></td>
<td>$CG_{LLP}$</td>
<td>DMP #303</td>
<td>Scf</td>
</tr>
</tbody>
</table>
B.4.4.2.1 Flare Gas Volume Allocation

The common flare gas volume $FLV_{Total}$ measured by the LP and HP flare header meters, DMP #141 and DMP #142, will be allocated to each of the separator as follows:

$$ AFL_i = \frac{SGTGVi - CGi}{\sum(SGTGVi - CGi)} \times (FLV_{Total} - \sum FLV_{Events,j}) + FLV_{event,i} \quad (B.3) $$

Where:

- $AFL_i$: flare gas volume allocated to separator $i$, scf
- $SGTGVi$: gross theoretical gas volume at separator $i$, scf
- $CGi$: circulated gas volume at separator $i$, scf
- $FLV_{Total}$: total common flare volume $i$, scf
- $FLV_{Events,j}$: event-driven flare volume at separator $j$, scf
- $FLV_{events,i}$: event-driven flare volume at separator $i$, scf

The $SGTGVi$ is the sum of the separator measured gas volume, converted to standard conditions, plus the theoretical flash gas from the separator liquid outlet. $SGTGVi$ is the first two terms of Equation (B.2).

In the case of an event driven flare, total flare volume will be assigned to the specific separator responsible for the flaring event.

B.4.4.2.2 Fuel Gas Volume Allocation

The total facility fuel gas volume $FUV_{Total}$ measured by the fuel load meter, DMP #304, and the fuel gas volume utilized for electricity generation $FUV_{electrical}$ measured by DMP #305, will be allocated to each of the separator as follows:

$$ AFU_i = AFU_{compression,i} + AFU_{electrical,i} \quad (B.4) $$

Where:

- $AFU_i$: fuel gas volume attributed to separator $i$, scf
- $AFU_{compression,i}$: compression fuel gas volume attributed to separator $i$, scf
- $AFU_{electrical,i}$: electrical fuel gas volume attributed to separator $i$, scf
- $STOV_i$: net theoretical oil volume at separator $i$, stb
- $SGTGVi$: gross theoretical oil volume at separator $i$, scf
- $FUV_{Total}$: total common fuel volume $i$, scf

B.4.4.2.3 Gas Moisture Correction

The calculation of the theoretical oil and gas quantities include the gas volume on a dry gas basis. The measured separator gas, however, contains water vapor. The water vapor fraction can be estimated by
assuming the gas phase is saturated with water vapor at separator conditions. This assumption represents the maximum amount of water vapor that the gas can hold at prevailing separator conditions.

The saturated water vapor fraction in the gas can be calculated from Equation (16) in Section 7.5.3.2.2 of the normative part of this document,

\[ X_{wg} = 1 - \frac{P_{water \ vapor}}{P_{Total}} \]  

(B.7)

Where:
- \( X_{wg} \) volume fraction of water vapor in the separator gas
- \( P_{water \ vapor} \) partial pressure of water vapor at separator conditions, psia
- \( P_{Total} \) separator pressure, psia

Assuming ideal gas and liquid mixtures, the water vapor pressure can be estimated using the Antoine equation,

\[ P_{water \ vapor} = 10^{\left(A - \frac{B}{T + C}\right)} \]  

(B.8)

Where:
- \( P_{water \ vapor} \) partial pressure of water vapor at separator conditions, mm Hg
- \( T \) separator temperature, °C
- \( A, B, C \) Antoine equation pure component coefficients

The Antoine equation parameters for water are listed in Table B.17.

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>( T_{min} ) °C</th>
<th>( T_{max} ) °C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>8.07131</td>
<td>1730.63</td>
<td>233.426</td>
<td>1</td>
<td>100</td>
</tr>
</tbody>
</table>

**B.4.4.3 Determination of Theoretical Water Quantities**

The theoretical water volume for each lease is the basis for the Tier 1 allocation of the overboard water volume, measured at DMP #136, to the lease level.

The lease level net theoretical water volume is determined from the separator liquid outlet with S&W applied and corrected to standard conditions.

Lease Unit \( j \) net theoretical water quantity, determined at inlet separator \( i \), except for the LP separator, is as follows:

\[ STWV_i = MLV_i \times X_{w,i} \times \frac{1}{B_{w,i}} \]  

(B.9)

Where:
- \( STWV_i \) net theoretical water volume at separator \( i \), stb
- \( MLV_i \) measured liquid volume at separator \( i \), bbl separator conditions
- \( X_{w,i} \) water cut of separator \( i \) liquid outlet from the online analyser, at separator conditions
- \( B_{w,i} \) water volume factor, sep bbl/stb
The LP separator is a three-phase separator; theoretical water volume is calculated as follows:

\[ STWV_{\text{LP}} = (MWV_{\text{LP}} + MOV_{\text{LP}} \times X_{w,\text{LP}}) \times \frac{1}{B_{w,\text{LP}}} \]  

(B.10)

Where:
- \(STWV_{\text{LP}}\) net theoretical water volume at LP separator, stb
- \(MWV_{\text{LP}}\) measured water volume by DMP#124 at LP separator, bbl separator conditions
- \(MOV_{\text{LP}}\) measured oil volume by DMP#114 at LP separator, bbl separator conditions
- \(X_{w,\text{LP}}\) water cut measured at AO#114 at LP separator, separator conditions
- \(B_{w,\text{LP}}\) water volume factor, sep bbl/stb

Equation (B.9) is equivalent to Equation (23) in Section 7.5.5.2 of the normative part of the document. Table B.18 lists the input data, source and unit for the theoretical water volume calculation for each of the leases.

### Table B.18 List of Input Data and Source to Calculate Lease Theoretical Water Volume

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Source</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease Unit A</td>
<td>MILV&lt;sub&gt;IP&lt;/sub&gt;</td>
<td>DMP #112</td>
<td>separator bbl</td>
</tr>
<tr>
<td>IP Separator</td>
<td>X&lt;sub&gt;w,IP&lt;/sub&gt;</td>
<td>AO #112</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>B&lt;sub&gt;w,IP&lt;/sub&gt;</td>
<td>Calculated from Equations (6) and (7) in Section 7.4.5.4 in this document</td>
<td>bbl/stb</td>
</tr>
<tr>
<td>Lease Unit B</td>
<td>MOV&lt;sub&gt;LP&lt;/sub&gt;</td>
<td>DMP #114</td>
<td>separator bbl</td>
</tr>
<tr>
<td>LP Separators</td>
<td>X&lt;sub&gt;w,LP&lt;/sub&gt;</td>
<td>AO #114</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>MWV&lt;sub&gt;LP&lt;/sub&gt;</td>
<td>DMP#124</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>B&lt;sub&gt;w,LP&lt;/sub&gt;</td>
<td>Calculated from Equations (6) and (7) in Section 7.4.5.4 in this document</td>
<td>bbl/stb</td>
</tr>
<tr>
<td>Lease Unit C</td>
<td>MILV&lt;sub&gt;LLP&lt;/sub&gt;</td>
<td>DMP #115</td>
<td>separator bbl</td>
</tr>
<tr>
<td>LLP Separator</td>
<td>X&lt;sub&gt;w,LLP&lt;/sub&gt;</td>
<td>AO #115</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>B&lt;sub&gt;w,LLP&lt;/sub&gt;</td>
<td>Calculated from Equations (6) and (7) in Section 7.4.5.4 in this document</td>
<td>bbl/stb</td>
</tr>
</tbody>
</table>
B.4.5 Allocation Method

B.4.5.1 Tier 1 Allocation Method – Lease Level

A volume-based proportional allocation will be utilized to distribute the sales oil, sales gas and overboard water to the contributing Lease Units A, B and C. A lease allocation factor will be calculated based on the ratio of the theoretical quantity (oil, gas or water) determined for a lease to the sum of the theoretical quantities for all the leases.

B.4.5.1.1 Sales Oil Allocation

Sales oil will be allocated as follows:

\[
ASOV_i = \frac{STOV_i}{\sum STOV_i} \times (LACT - BBO)
\]  

(B.11)

Where:

- \(ASOV_i\) allocated sales oil volume to separator \(i\), stb
- \(STOV_i\) net theoretical oil volume at separator \(i\), stb
- \(LACT\) oil sales volume measured at the LACT unit, stb
- \(BBO\) total buy back oil volume, stb

B.4.5.1.2 Sales Gas Allocation

Sales gas will be allocated as follows:

\[
ASGV_i = \frac{STGV_i}{\sum STGV_i} \times (SGV - BBG)
\]  

(B.12)

Where:

- \(ASGV_i\) allocated sales gas volume to separator \(i\), scf
- \(STGV_i\) net theoretical gas volume at separator \(i\), scf
- \(SGV\) sales gas volume measured at sales gas metering skid, scf
- \(BBG\) total buy back gas volume, scf

B.4.5.1.3 Overboard Water Allocation

Water will be allocated as follows:

\[
APWV_i = \frac{STWV_i}{\sum STWV_i} \times (OWV + LACT \times S&W)
\]  

(B.13)

Where:

- \(APWV_i\) allocated produced water volume to separator \(i\), stb
- \(STWV_i\) net theoretical water volume at separator \(i\), stb
- \(OWV\) overboard water volume, stb
- \(LACT\) oil sales volume measured at the LACT unit, stb
- \(S&W\) S&W measured at the LACT unit online analyser, stb/stb
B.4.5.2 Tier 2 Allocation Method – Well Level

B.4.5.2.1 General

Well testing will be the primary method used for Tier 2, well level allocation of sales oil, sales gas and overboard water volumes for Lease Units A and C. A combination of well testing and continuous measurement will be used for Tier 2 allocation for Lease Unit B.

B.4.5.2.2 Well Level Oil Allocation

B.4.5.2.2.1 Lease Unit A Well Level Oil Allocation

Lease Unit A allocated sales oil volume will be distributed to Wells 1, 2, and 3 based on periodic well test, as follows:

\[ WAOV_i = \frac{WTOV_i}{\sum WTOV_i} \times ASOV_{Lease A} \]  \hspace{1cm} (B.14)

Where:
- \( WAOV_i \): Well allocated oil volume to Well \( i \), stb
- \( WTOV_i \): Well test oil volume determined for Well \( i \), stb (determined from well test in accordance with API MPMS 20.5)
- \( ASOV_{Lease A} \): Lease A allocated sales oil volume, stb
- \( i \): Wells 1, 2 and 3

B.4.5.2.2.2 Lease Unit B Well Level Oil Allocation

Lease Unit B allocated sales oil volume will be distributed to Well 4 and Well 5, based on continuous measurement and periodic well test, respectively. The allocation equations for Wells 4 and 5 are as follows:

\[ WAOV_4 = \frac{TOV_4}{TOV_4 + WTOV_5} \times ASOV_{Lease B} \]  \hspace{1cm} (B.15)

\[ WAOV_5 = \frac{WTOV_5}{TOV_4 + WTOV_5} \times ASOV_{Lease B} \]  \hspace{1cm} (B.16)

Where:
- \( WAOV_i \): Well 4 allocated oil volume, stb
- \( TOV_4 \): Well 4 theoretical oil volume, stb
- \( WTOV_5 \): Well 5 well test oil volume, stb (determined from well test in accordance with API MPMS 20.5)
- \( ASOV_{Lease B} \): Lease B allocated sales oil volume, stb

Well 4 theoretical oil volume is calculated as follows:

\[ TOV_4 = MLV_{HP} \times (1 - X_{w,HP}) \times SF_{HP} + MGV_{HP} \times (1 - X_{w,HP}) \times \frac{1}{\beta_{p,HP}} \times r_{s,HP} \]  \hspace{1cm} (B.17)

B.4.5.2.2.3 Lease Unit C Well Level Oil Allocation

Lease C allocated sales oil volume will be distributed to Wells 6 and 7 based on well test, as follows:

\[ WAOV_j = \frac{WTOV_j}{\sum WTOV_j} \times ASOV_{Lease C} \]  \hspace{1cm} (B.18)
B.4.5.2.3 Well Level Gas Allocation

B.4.5.2.3.1 Lease Unit A Well Level Gas Allocation

Lease Unit A allocated sales gas volume will be distributed to Wells 1, 2, and 3 based on well test, as follows:

\[ WAGV_i = \frac{WTGV_i}{\sum WTGV_i} \times ASGV_{\text{Lease A}} \]  

(B.19)

Where:

- \( WAGV_i \): well allocated gas volume to Well \( i \), scf
- \( WTVG_i \): well test gas volume determined for Well \( i \), scf (determined from well test in accordance with API MPMS 20.5)
- \( ASGV_{\text{Lease A}} \): Lease A allocated sales gas volume, scf
- \( i \): Wells 1, 2 and 3

B.4.5.2.3.2 Lease Unit B Well Level Gas Allocation

Wells 4 and 5 on Lease Unit B have different ownership (see Table B.11) and large discrepancy in production rates. Well 4 is measured continuously at the HP separator where the primary gas outlet goes directly to the dehydration unit. The primary liquid outlet commingles with Well 5 production and goes to the LP separator. The LP separator gas and liquid outlets comprise of commingled production from both wells. Wells 4 and 5 will have different fuel utilization and flare assignment due to differences in production rate and process arrangement. **A technically rigorous well level allocation of the lease allocated sales gas volume would require the determination of gas consumption (fuel and flare) per well.** Whilst technically feasible, partners recognize that this would impose additional financial and operational burden that could negate or outweigh any benefits. Disregard of the gas consumption per well in the gas allocation algorithm would be a pragmatic alternative though one that results in potential bias.

Partners were made aware of the potential bias but agreed that sales gas allocation at Lease Unit B will be conducted without regard to gas consumption per well. This is reflected in the commercial requirements.

Lease Unit B allocated sales oil volume will be distributed to Well 4 and Well 5, based on continuous measurement and well test, respectively. The allocation equations for Wells 4 and 5 are as follows:

\[ WAGV_4 = \frac{TGV_4}{TGV_4 + WTGV_5} \times ASGV_{\text{Lease B}} \]  

(B.20)

\[ WAGV_5 = \frac{WTGV_5}{TGV_4 + WTGV_5} \times ASGV_{\text{Lease B}} \]  

(B.21)

Where:

- \( WAGV_4 \): Well 4 allocated gas volume, scf
- \( TGV_4 \): Well 4 theoretical gas volume, scf
WTGV₅  Well 5 well test gas volume, scf (determined from well test in accordance with API MPMS Ch. 20.5)

ASGVₗₑᵃˢᵉ₆  Lease B allocated sales gas volume, scf

Well 4 theoretical gas volume is calculated as follows:

\[ TGV₄ = MGV_{HP} \times (1 - X_{w,HP}) \times \frac{1}{B_{g,HP}} + MLV_{HP} \times (1 - X_{w,HP}) \times SF_{HP} \times FF_{HP} \]  \hspace{1cm} (B.22)

Where:

\( TGV₄ \)  \hspace{0.5cm} Well 4 theoretical gas volume, scf

\( MGV_{HP} \)  \hspace{0.5cm} measure gas volume at HP separator by DMP #103, mcf

\( X_{w,HP} \)  \hspace{0.5cm} water volume fraction in HP separator gas, separator conditions

\( B_{g,HP} \)  \hspace{0.5cm} HP separator gas volume factor, sep cf/scf

\( MLV_{HP} \)  \hspace{0.5cm} measured liquid volume at HP separator by DMP #113, bbl separator conditions

\( X_{w,HP} \)  \hspace{0.5cm} water cut of HP separator liquid outlet measured by AO #113, separator conditions

\( SF_{HP} \)  \hspace{0.5cm} HP separator oil shrinkage factor, stb/separator oil bbl

\( FF_{HP} \)  \hspace{0.5cm} HP separator oil flash gas factor, scf evolved gas/separator oil stb

B.4.5.2.3.3  Lease Unit C Well Level Gas Allocation

Lease C allocated sales gas volume will be distributed to Wells 6 and 7 based on well test, as follows:

\[ WAGV_{j} = \frac{WTGV_{j}}{\sum WTV_{j}} \times ASGV_{ₗₑᵃˢᵉ₆} \]  \hspace{1cm} (B.23)

Where:

\( WAGV_{j} \)  \hspace{0.5cm} well allocated gas volume to Well \( j \), scf

\( WTV_{j} \)  \hspace{0.5cm} well test gas volume determined for Well \( j \), scf (determined from well test in accordance with API MPMS 20.5)

\( ASGV_{ₗₑᵃˢᵉ₆} \)  \hspace{0.5cm} Lease C allocated sales gas volume, stb

\( j \)  \hspace{0.5cm} Wells 6 and 7

B.4.5.2.4  Well Level Water Allocation

B.4.5.2.4.1  Lease Unit A Well Level Water Allocation

Lease Unit A allocated produced water volume will be distributed to Wells 1, 2, and 3 based on well tests, as follows:

\[ WAWV_{i} = \frac{WTWV_{i}}{\sum WTV_{i}} \times APWV_{ₗₑᵃˢᵉ₆} \]  \hspace{1cm} (B.24)

Where:

\( WAWV_{i} \)  \hspace{0.5cm} well allocated water volume to Well \( i \), stb

\( WTWV_{i} \)  \hspace{0.5cm} well test water volume determined for Well \( i \), stb (determined from well test in accordance with API MPMS 20.5)

\( APWV_{ₗₑᵃˢᵉ₆} \)  \hspace{0.5cm} Lease A allocated produced water volume, stb

\( i \)  \hspace{0.5cm} Wells 1, 2 and 3

110
B.4.5.2.4.2 Lease Unit B Well Level Water Allocation

Lease Unit B allocated sales oil volume will be distributed to Well 4 and Well 5, based on continuous measurement and well test, respectively. The allocation equations for Wells 4 and 5 are as follows:

\[
W_{AWV4} = \frac{TWV4}{TWV4 + WTWV5} \times APWV_{Lease B}
\]  
(B.25)

\[
W_{AWV5} = \frac{WTWV5}{TWV4 + WTWV5} \times APWV_{Lease B}
\]  
(B.26)

Where:

- \(W_{AWV4}\) Well 4 allocated water volume, stb
- \(TWV4\) Well 4 theoretical water volume, stb
- \(WTWV5\) Well 5 well test water volume, stb (determined from well test in accordance with API MPMS 20.5)
- \(APWV_{Lease B}\) Lease B allocated produced volume, stb

\[
TWV4 = MLV_{HP} \times X_{w,HP} \times \frac{1}{b_{w,HP}}
\]  
(B.27)

B.4.5.2.4.3 Lease Unit C Well Level Water Allocation

Lease C allocated produced water volume will be distributed to Wells 6 and 7 based on well test, as follows:

\[
W_{AWVj} = \frac{WTWVj}{\sum WTWVj} \times APWV_{Lease C}
\]  
(B.28)

Where:

- \(W_{AWVj}\) well allocated water volume to Well \(j\), stb
- \(WTWVj\) well test water volume determined for Well \(j\), stb (determined from well test in accordance with API MPMS 20.5)
- \(APWV_{Lease C}\) Lease C allocated sales water volume, stb
- \(j\) Wells 6 and 7

B.4.6 Numerical Worked Example for the Offshore Allocation

The worked example in the following sections to show the calculation for the allocation of the sales oil, sales gas and overboard water production volumes to the lease and well levels. The example is based on input quantities detailed in the sections below.

B.4.6.1 Theoretical Quantities Calculation

The following sections show the calculation of the theoretical quantities at the lease level.

B.4.6.1.1 Theoretical Oil Quantity Calculation

The input quantities comprising of measured and laboratory determined PVT properties for the theoretical oil volume calculation are provided in Table B.19.
Table B.19 List of Input Quantities to Calculate Lease Theoretical Oil Volume

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Lease Unit A</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>IP Separator</strong></td>
<td>$P_{IP}$ (flow weighted avg.)</td>
<td>619</td>
<td>psia</td>
</tr>
<tr>
<td></td>
<td>$T_{IP}$ (flow weighted avg.)</td>
<td>160</td>
<td>°F</td>
</tr>
<tr>
<td></td>
<td>$MLV_{IP}$</td>
<td>1,336,947</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>$X_{w,IP}$</td>
<td>0.318</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{IP}$</td>
<td>0.907</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$MGV_{IP}$</td>
<td>41,772</td>
<td>mcf, separator condition</td>
</tr>
<tr>
<td></td>
<td>$X_{wg,IP}$ (calc. from Eqn. B.7)</td>
<td>0.00764</td>
<td>water volume fraction, separator gas condition</td>
</tr>
<tr>
<td></td>
<td>$B_{g,IP}$</td>
<td>0.0282</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>$r_{s,IP}$</td>
<td>0.0</td>
<td>stb/scf</td>
</tr>
<tr>
<td></td>
<td>$CO_{IP}$</td>
<td>-</td>
<td>stb</td>
</tr>
<tr>
<td></td>
<td>$\Delta ln_{IP}$</td>
<td>-</td>
<td>stb</td>
</tr>
<tr>
<td><strong>Lease Unit B</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>HP and LP Separators</strong></td>
<td>$P_{HP}$ &amp; $P_{LP}$ (flow weighted avg.)</td>
<td>$P_{HP}$ = 810, $P_{LP}$ = 607</td>
<td>psia</td>
</tr>
<tr>
<td></td>
<td>$T_{HP}$ &amp; $T_{LP}$ (flow weighted avg.)</td>
<td>$T_{HP}$ = 165, $T_{LP}$ = 125</td>
<td>°F</td>
</tr>
<tr>
<td></td>
<td>$MOV_{LP}$</td>
<td>583,027</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>$X_{w,LP}$</td>
<td>0.005</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>$SF_{LP}$</td>
<td>0.871</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>$MGV_{HP}$ and $MGV_{LP}$</td>
<td>$MGV_{HP}$ = 10,519, $MGV_{LP}$ = 16,527</td>
<td>mcf, separator condition</td>
</tr>
<tr>
<td></td>
<td>$X_{wg,HP}$ and $X_{wg,LP}$ (calc. from Eqn B.7)</td>
<td>$X_{wg,HP}$ = 0.00657, $X_{wg,LP}$ = 0.00319</td>
<td>water volume fraction, separator gas condition</td>
</tr>
<tr>
<td></td>
<td>$B_{g,HP}$ and $B_{g,LP}$</td>
<td>$B_{g,HP}$ = 0.0217, $B_{g,LP}$ = 0.0272</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>$r_{s,HP}$ and $r_{s,LP}$</td>
<td>$r_{s,HP}$ = 0.0, $r_{s,LP}$ = 0.0</td>
<td>stb/scf</td>
</tr>
</tbody>
</table>
The theoretical oil volume for each lease is calculated from Equation (B.1):

Lease A theoretical oil volume is calculated from the IP separator:

\[
STOV_{IP} = \left( 1,336,947 \text{ bbl} \times (1 - 0.318) \times 0.907 \frac{\text{stb}}{\text{bbl}} \right) + \left\{ 41,772 \text{ mcf} \times (1 - 0.00764) \times \frac{1 \text{ mcf}}{0.0282 \text{ mscf}} \times 0 \frac{\text{stb}}{\text{mscf}} \right\} = 827,001 \text{ stb}
\]

Lease B theoretical oil volume is calculated from the LP separator:

\[
STOV_{LP} = \left( 583,027 \text{ bbl} \times (1 - 0.005) \times 0.871 \frac{\text{stb}}{\text{bbl}} \right) + \left\{ 10,519 \text{ mcf} \times (1 - 0.00657) \times \frac{1 \text{ mcf}}{0.0217 \text{ mscf}} \times 0 \frac{\text{stb}}{\text{mscf}} \right\} + \left\{ 16,527 \text{ mcf} \times (1 - 0.00319) \times \frac{1 \text{ mcf}}{0.0272 \text{ mscf}} \times 0 \frac{\text{stb}}{\text{mscf}} \right\} = 505,277 \text{ stb}
\]

Lease C theoretical oil volume is calculated from the LLP separator:
\[ STOV_{LLP} = \left\{ 166,579 \text{ bbl} \times (1 - 0.135) \times 0.892 \frac{\text{stb}}{\text{bbl}} \right\} + \left\{ 8,018 \text{ mcf} \times (1 - 0.00313) \times \frac{1}{0.0311} \frac{\text{mcf}}{\text{mcf}} \times 0 \frac{\text{stb}}{\text{mcf}} \right\} - 5,000 \text{ stb} \\
= 123,529 \text{ stb} \]

The facility total theoretical oil volume, FTOV, is the sum of the theoretical oil volume for all the leases.

\[ FTOV = 827,001 + 505,277 + 123,529 = 1,455,807 \text{ stb oil} \]

### B.4.6.1.2 Theoretical Gas Quantity Calculation

The input quantities comprising of measured and laboratory determined PVT properties for the theoretical gas volume calculation are provided in Table B.20.

#### Table B.20 List of Input Quantities to Calculate Lease Theoretical Gas Volume

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease Unit A</td>
<td>MGV_{IP}</td>
<td>41,772</td>
<td>mcf, separator condition</td>
</tr>
<tr>
<td></td>
<td>X_{wg,IP} (calc. from Eqn. B.7)</td>
<td>0.00764</td>
<td>water volume fraction, separator condition</td>
</tr>
<tr>
<td></td>
<td>B_{g,IP}</td>
<td>0.0282</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td></td>
<td>MLV_{IP}</td>
<td>1,336,947</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>X_{w,IP}</td>
<td>0.318</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>SF_{IP}</td>
<td>0.907</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td></td>
<td>FF_{IP}</td>
<td>0.214</td>
<td>mscf/stb</td>
</tr>
<tr>
<td></td>
<td>AFL_{IP}</td>
<td></td>
<td>scf</td>
</tr>
<tr>
<td></td>
<td>AFU_{IP}</td>
<td></td>
<td>scf</td>
</tr>
<tr>
<td></td>
<td>CG_{IP}</td>
<td>N/A</td>
<td>scf</td>
</tr>
</tbody>
</table>

**Lease Unit B HP and LP Separators**

<table>
<thead>
<tr>
<th>Input Data</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
</table>
| MGV_{HP} and MGV_{LP} | \begin{align*}
                      & MGV_{HP} = 10,519 \\
                      & MGV_{LP} = 16,527
\end{align*} | mcf, separator condition |
| X_{wg,HP} and X_{wg,LP} | \begin{align*}
                      & X_{wg,HP} = 0.00657 \\
                      & X_{wg,LP} = 0.00319
\end{align*} | water volume fraction, separator gas condition |
| B_{g,HP} and B_{g,LP} | \begin{align*}
                      & B_{g,HP} = 0.0217 \\
                      & B_{g,LP} = 0.0272
\end{align*} | separator cu ft/scf |
| MOV_{LP}              | 583,027   | separator bbl              |
### Lease Unit/Separator

<table>
<thead>
<tr>
<th>Input Data</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$X_{w,LP}$</td>
<td>0.005</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td>$SF_{LP}$</td>
<td>0.871</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td>$FF_{LP}$</td>
<td>0.186</td>
<td>scf/stb</td>
</tr>
<tr>
<td>$AFL_{HP}$ and $AFL_{LP}$</td>
<td>Attributed from DMP #141 and DMP #142</td>
<td>scf</td>
</tr>
<tr>
<td>$AFU_{LP}$</td>
<td>Attributed from DMP #304</td>
<td>scf</td>
</tr>
<tr>
<td>$CG_{HP}$</td>
<td>N/A</td>
<td>scf</td>
</tr>
<tr>
<td>$CG_{LP}$</td>
<td>N/A</td>
<td>scf</td>
</tr>
</tbody>
</table>

### Lease Unit C

#### LLP Separator

<table>
<thead>
<tr>
<th>Input Data</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$MGV_{LLP}$</td>
<td>8,018</td>
<td>cu. ft. separator condition</td>
</tr>
<tr>
<td>$X_{w,LLP}$</td>
<td>0.003128</td>
<td>water volume fraction, separator condition</td>
</tr>
<tr>
<td>$B_{g,LLP}$</td>
<td>0.03109</td>
<td>separator cu ft/scf</td>
</tr>
<tr>
<td>$MLV_{LLP}$</td>
<td>166,579</td>
<td>separator bbl</td>
</tr>
<tr>
<td>$X_{w,LLP}$</td>
<td>0.135</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td>$SF_{LLP}$</td>
<td>0.892</td>
<td>stb/separator bbl</td>
</tr>
<tr>
<td>$FF_{LLP}$</td>
<td>0.102</td>
<td>mscf/stb</td>
</tr>
<tr>
<td>$AFL_{LLP}$</td>
<td>Attributed from DMP #141 and DMP #142</td>
<td>mscf</td>
</tr>
<tr>
<td>$AFU_{LLP}$</td>
<td>Attributed from DMP #304</td>
<td>mscf</td>
</tr>
<tr>
<td>$CG_{LLP}$</td>
<td>50,000</td>
<td>mscf</td>
</tr>
</tbody>
</table>

### Flare and Fuel Volumes

<table>
<thead>
<tr>
<th>Input Data</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$FLV_{Total}$ (DMP #142 and DMP #143)</td>
<td>30,075</td>
<td>mscf</td>
</tr>
<tr>
<td>$FLV_{event}$</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td>$FUV_{Total}$ (DMP #304)</td>
<td>182,844</td>
<td>mscf</td>
</tr>
<tr>
<td>$FUV_{electrical}$ (DMP #305)</td>
<td>63,995</td>
<td>mscf</td>
</tr>
</tbody>
</table>

The gross theoretical gas volume calculation from each lease is calculated from Equation (B.2), using only the first two terms.

Lease A gross theoretical gas volume is calculated from the IP separator:
\[
SGTGV_{IP} = 41,772 \text{ mcf} \times (1 - 0.00764) \times \frac{1 \text{ mcf}}{0.0282 \text{ mcf}} + 1,366,947 \text{ bbl} \times (1 - 0.318) \times 0.907 \frac{\text{ mcf}}{\text{ bbl}} \times 0.214 \frac{\text{ mcf}}{\text{ stb}} = 1,644,904 \text{ mcf}
\]

Lease B gross theoretical gas volume is calculated from the HP and LP separators:

\[
SGTGV_{HP} + SGTGV_{IP} = 10,519 \text{ mcf} \times (1 - 0.00657) \times \frac{1 \text{ mcf}}{0.0217 \text{ mcf}} + 16,527 \text{ mcf} \times (1 - 0.00319) \times \frac{1 \text{ mcf}}{0.0272 \text{ mcf}} + 583,027 \text{ bbl} \times (1 - 0.005) \times 0.871 \frac{\text{ mcf}}{\text{ bbl}} \times 0.186 \frac{\text{ mcf}}{\text{ stb}} = 1,180,562 \text{ mcf}
\]

Lease C gross theoretical gas volume is calculated from the LLP separator:

\[
SGTGV_{LLP} = 8,018 \text{ mcf} \times (1 - 0.00313) \times \frac{1 \text{ mcf}}{0.03109 \text{ mcf}} + 166,579 \text{ bbl} \times (1 - 0.135) \times 0.892 \frac{\text{ mcf}}{\text{ bbl}} \times 0.102 \frac{\text{ mcf}}{\text{ stb}} = 269,658 \text{ mcf}
\]

Sum of gross theoretical gas volume for all the leases:

\[
\sum SGTGV_i = 1,644,904 + 1,180,562 + 269,658 = 3,095,125 \text{ mcf}
\]

Flare gas volume allocation is calculated from Equation (B.3).

Lease A flare gas volume assigned to IP separator is calculated as follows:

\[
AFL_{IP} = \frac{1,644,904}{3,095,125 - 50,000} \times (30,075 - 0) + 0 = 16,246 \text{ mcf}
\]

Lease B flare gas volume assigned to HP and IP separators are calculated as follows:

\[
AFL_{HP} + AFL_{IP} = \frac{1,180,562}{3,095,125 - 50,000} \times (30,075 - 0) + 0 = 11,660 \text{ mcf}
\]

Lease C flare gas volume assigned to LLP separator, accounting for circulated gas lift volume, is calculated as follows:

\[
AFL_{LLP} = \frac{269,658 - 50,000}{3,095,125 - 50,000} \times (30,075 - 0) + 0 = 2,169 \text{ mcf}
\]

Fuel gas volume allocation is calculated from Equation (B.4), (B.5) and (B.6).

Lease A fuel gas volume is calculated from the IP separator is calculated as follows:

\[
AFU_{IP} = \frac{827,001}{827,001 + 505,277 + 123,529} \times 65,608 = 37,270 \text{ mcf}
\]
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Lease B fuel gas volume is calculated from the LP separator as follows:

\[
AFU_{LP} = 37,270 + 76,659 = 113,929 \text{ mscf}
\]

Lease C fuel gas allocation is calculated from the LLP separator as follows:

\[
AFU_{LP} = 22,771 + 32,617 = 55,388 \text{ mscf}
\]

The theoretical gas volume for each lease is calculated from Equation (B.2).

Lease A theoretical gas volume is calculated from the IP separator:

\[
STGV_{IP} = 1,644,904 - 16,246 - 113,929 - 0 = 1,514,729 \text{ mscf}
\]

Lease B theoretical gas volume is calculated from the HP and LP separators:

\[
STGV_{HP} + STGV_{LP} = 1,180,562 - 11,660 - 55,388 - 0 = 1,113,515 \text{ mscf}
\]

Lease C theoretical gas volume is calculated from the LLP separator:

\[
STGV_{LLP} = 269,658 - 2,169 - 18,134 - 50,000 = 199,354 \text{ mscf}
\]

The facility total theoretical gas volume, FTGV, is the sum of the lease theoretical gas volumes,

\[
FTGV = 1,514,729 + 1,113,515 + 199,354 = 2,827,599 \text{ mscf gas}
\]

B.4.6.1.3 Theoretical Water Quantity Determination

The input quantities comprising of measured and laboratory determined PVT properties for the theoretical water volume calculation are provided in Table B.21.
Table B.21 List of Input Quantities to Calculate Lease Theoretical Water Volume

<table>
<thead>
<tr>
<th>Lease Unit/Separator</th>
<th>Input Data</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease Unit A</td>
<td>MLV&lt;sub&gt;IP&lt;/sub&gt;</td>
<td>1,336,947</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>X&lt;sub&gt;w,IP&lt;/sub&gt;</td>
<td>0.318</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>B&lt;sub&gt;w,IP&lt;/sub&gt;</td>
<td>1.0259</td>
<td>bbl/stb</td>
</tr>
<tr>
<td>Lease Unit B</td>
<td>MOV&lt;sub&gt;LP&lt;/sub&gt;</td>
<td>583,027</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>X&lt;sub&gt;w,LP&lt;/sub&gt;</td>
<td>0.005</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>MWV&lt;sub&gt;LP&lt;/sub&gt;</td>
<td>57,662</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>B&lt;sub&gt;w,LP&lt;/sub&gt;</td>
<td>1.0139</td>
<td>bbl/stb</td>
</tr>
<tr>
<td>Lease Unit C</td>
<td>MLV&lt;sub&gt;LLP&lt;/sub&gt;</td>
<td>166,579</td>
<td>separator bbl</td>
</tr>
<tr>
<td></td>
<td>X&lt;sub&gt;w,LLP&lt;/sub&gt;</td>
<td>0.135</td>
<td>water cut, bbl/bbl</td>
</tr>
<tr>
<td></td>
<td>B&lt;sub&gt;w,LLP&lt;/sub&gt;</td>
<td>1.0121</td>
<td>bbl/stb</td>
</tr>
</tbody>
</table>

The theoretical water volume for each lease is calculated from Equation (B.9).

Lease A theoretical water volume is calculated from the IP separator:

\[ STWV_{IP} = 1,366,947 \text{ bbl water} \times 0.318 \times \frac{1}{1.0259} = 404,436 \text{ stb water} \]

Lease B theoretical water volume is calculated from the LP separator:

\[ STWV_{LP} = (57,662 + 583,027 \times 0.005) \text{ bbl water} \times \frac{1}{1.0139} = 59,874 \text{ stb water} \]

Lease C theoretical water volume is calculated from the LLP separator:

\[ STWV_{LLP} = 166,579 \text{ bbl water} \times 0.135 \times \frac{1}{1.0121} = 22,219 \text{ stb water} \]

The facility total theoretical water volume, FTWV, is the sum of the lease theoretical water volumes,

\[ FTWV = 404,436 + 59,749 + 22,219 = 496,404 \text{ stb water} \]

B.4.6.2 Tier 1 Allocation – Lease Level

The sales oil, sales gas and overboard water volumes for the allocation period, along with buy back quantities of oil and gas, are listed in Table B.22.
Table B.22 Export Oil and Gas, Overboard Water Volumes and Buy Back Quantities

<table>
<thead>
<tr>
<th>Product</th>
<th>Quantity</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales oil (LACT)</td>
<td>1,438,544</td>
<td>stb</td>
</tr>
<tr>
<td>S&amp;W</td>
<td>0.15%</td>
<td></td>
</tr>
<tr>
<td>Buy back oil</td>
<td>0</td>
<td>stb</td>
</tr>
<tr>
<td>Sales Gas</td>
<td>2,746,575</td>
<td>mscf</td>
</tr>
<tr>
<td>Buy back gas</td>
<td>0</td>
<td>mscf</td>
</tr>
<tr>
<td>Overboard Water</td>
<td>510,127</td>
<td>stb</td>
</tr>
</tbody>
</table>

B.4.6.2.1 Sales Oil Allocation to Leases

The allocation of the sales oil volume to the leases is calculated using Equation (B.11).

Lease A sales oil volume allocation is calculated from the IP separator:

\[
ASOV_{IP} = \frac{827,001}{1,455,807} \times (1,438,544 - 0) = 817,194 \text{ stb}
\]

Lease B sales oil volume allocation is calculated from the LP separator:

\[
ASOV_{LP} = \frac{505,277}{1,455,807} \times (1,438,544 - 0) = 499,286 \text{ stb}
\]

Lease C sales oil volume allocation is calculated from the LLP separator:

\[
ASOV_{LLP} = \frac{123,529}{1,455,807} \times (1,438,544 - 0) = 122,064 \text{ stb}
\]

B.4.6.2.2 Sales Gas Allocation to Leases

The allocation of the sales gas volume to the leases is calculated using Equation (B.12).

Lease A sales gas volume allocation is calculated from the IP separator:

\[
ASGV_{IP} = \frac{1,514,729}{2,827,599} \times (2,746,575 - 0) = 1,471,325 \text{ mscf}
\]

Lease B sales gas volume allocation is calculated from the HP and LP separator:

\[
ASGV_{HP+LP} = \frac{1,113,515}{2,827,599} \times (2,746,575 - 0) = 1,081,607 \text{ mscf}
\]

Lease C sales gas volume allocation is calculated from the LLP separator:

\[
ASGV_{LLP} = \frac{199,354}{2,827,599} \times (2,746,575 - 0) = 193,642 \text{ mscf}
\]

B.4.6.2.3 Overboard Water Allocation to Leases

The allocation of the overboard water to the leases is calculated using Equation (B.13).

Lease A overboard water allocation is calculated from the IP separator:
Lease B overboard water allocation is calculated from the LP separator:

\[ APWV_{LP} = \frac{59,749}{496,404} \times (510,127 + 1,438,544 \times 0.0015) = 61,660 \text{ stb} \]

Lease C overboard water allocation is calculated from the LLP separator:

\[ APWV_{LLP} = \frac{22,219}{496,404} \times (510,127 + 1,438,544 \times 0.0015) = 22,930 \text{ stb} \]

### B.4.6.3 Tier 2 Allocation – Well Level

The lease allocated sales oil, sales gas and overboard water will be allocated to the wells based on well prorated volumes obtained from periodic well testing, except for Well 4. Well 4 is measured separately and continuously via the HP separator. Theoretical oil for Well 4 will be based on the oil volume measured by DMP #113, adjusted for water cut and shrinkage, plus the theoretical liquid dropout volume measured by DMP #103.

The test separator is utilized for well rate determination of Wells 1-3 and 5-6, in accordance with API MPMS 20.5 – RP for Application of Production Well Testing in Measurement and Allocation. Well prorated volumes for the allocation period, determined from the well tests are listed in Table B.23.

### Table B.23 Well Prorated Oil, Gas and Water Volumes Based on Periodic Well Tests

<table>
<thead>
<tr>
<th>Well</th>
<th>Prorated Oil stb</th>
<th>Prorated Gas mscf</th>
<th>Prorated Water stb</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>361,069</td>
<td>737,311</td>
<td>59,728</td>
</tr>
<tr>
<td>2</td>
<td>266,503</td>
<td>537,622</td>
<td>167,237</td>
</tr>
<tr>
<td>3</td>
<td>232,116</td>
<td>261,131</td>
<td>171,219</td>
</tr>
<tr>
<td>4</td>
<td>411,811</td>
<td>569,278</td>
<td>35,775</td>
</tr>
<tr>
<td>5</td>
<td>102,953</td>
<td>571,818</td>
<td>23,850</td>
</tr>
<tr>
<td>6</td>
<td>62,751</td>
<td>89,317</td>
<td>12,795</td>
</tr>
<tr>
<td>7</td>
<td>67,980</td>
<td>109,166</td>
<td>7,842</td>
</tr>
</tbody>
</table>

### B.4.6.3.1 Well Level Oil Allocation

The allocation of Lease A allocated sales oil volume to wells 1-3 is calculated from Equation (B.14):

\[
WAOV_1 = \frac{361,069}{(361,069 + 266,503 + 232,116)} \times 817,194 = 343,222 \text{ stb}
\]

\[
WAOV_2 = \frac{266,503}{(361,069 + 266,503 + 232,116)} \times 817,194 = 253,330 \text{ stb}
\]
The allocation of Lease B allocated sales oil volume to wells 4 and 5 is calculated from Equation (B.15) and (B.16):

\[ WAOV_4 = \frac{411,811}{(411,811 + 102,953)} \times 499,286 = 399,428 \text{ stb} \]

\[ WAOV_5 = \frac{102,953}{(411,811 + 102,953)} \times 499,286 = 99,857 \text{ stb} \]

The allocation of Lease C allocated sales oil volume to wells 6 and 7 is calculated from Equation (B.18):

\[ WAOV_6 = \frac{62,751}{(62,751 + 67,980)} \times 122,064 = 58,591 \text{ stb} \]

\[ WAOV_7 = \frac{67,980}{(62,751 + 67,980)} \times 122,064 = 63,473 \text{ stb} \]

### B.4.6.3.2 Well Level Gas Allocation

The allocation of Lease A allocated sales gas volume to wells 1-3 is calculated from Equation (B.19):

\[ WAGV_1 = \frac{737,311}{(737,311 + 537,622 + 261,131)} \times 1,471,325 = 706,236 \text{ mscf} \]

\[ WAGV_2 = \frac{537,622}{(737,311 + 537,622 + 261,131)} \times 1,471,325 = 514,964 \text{ mscf} \]

\[ WAGV_3 = \frac{261,131}{(737,311 + 537,622 + 261,131)} \times 1,471,325 = 250,125 \text{ mscf} \]

The allocation of Lease B allocated sales gas volume to wells 4 and 5 is calculated from Equation (B.20) and (B.21):

\[ WAGV_4 = \frac{569,278}{(569,278 + 571,818)} \times 1,081,607 = 539,600 \text{ mscf} \]

\[ WAGV_5 = \frac{571,818}{(569,278 + 571,818)} \times 1,081,607 = 542,008 \text{ mscf} \]

The allocation of Lease C allocated sales gas volume to wells 6 and 7 is calculated from Equation (B.23):

\[ WAGV_6 = \frac{89,317}{(89,317 + 109,166)} \times 193,642 = 87,139 \text{ mscf} \]

\[ WAGV_7 = \frac{109,166}{(89,317 + 109,166)} \times 193,642 = 106,503 \text{ mscf} \]

### B.4.6.3.3 Well Level Water Allocation

The allocation of Lease A allocated overboard water volume to wells 1-3 is calculated from Equation (B.24):
The allocation of Lease B allocated overboard water volume to wells 4 and 5 is calculated from Equations (B.25) and (B.26):

\[
WAWV_1 = \frac{59,728}{(59,728 + 167,237 + 171,219)} \times 427,694 = 64,154 \text{ stb}
\]

\[
WAWV_2 = \frac{167,237}{(59,728 + 167,237 + 171,219)} \times 427,694 = 179,632 \text{ stb}
\]

\[
WAWV_3 = \frac{171,219}{(59,728 + 167,237 + 171,219)} \times 427,694 = 183,909 \text{ stb}
\]

The allocation of Lease C allocated overboard water volume to wells 6 and 7 is calculated from Equation (B.28):

\[
WAWV_4 = \frac{35,775}{(35,775 + 23,850)} \times 61,660 = 36,996 \text{ stb}
\]

\[
WAWV_5 = \frac{23,850}{(35,775 + 23,850)} \times 61,660 = 24,664 \text{ stb}
\]

\[
WAWV_6 = \frac{13,193}{(13,193 + 8,086)} \times 22,930 = 14,216 \text{ stb}
\]

\[
WAWV_7 = \frac{8,086}{(13,193 + 8,086)} \times 22,930 = 8,713 \text{ stb}
\]

**B.4.6.4 Material Balance Factors**

The material balance factors for Tier 1 and Tier 2 level allocations are calculated from Equation (B.29):

\[
\text{Material Balance Factor} = \frac{\text{Reference Volume} - \text{Theoretical Volume}}{\text{Reference Volume}} \times 100\% 
\]

(B.29)

where the Reference Volume is the oil, gas and overboard water volumes at the sales and lease allocated levels.

The material balance between facility oil, gas and water output and the lease level theoretical quantities constitutes the Tier 1 performance for the offshore scenario, listed in Table B.24.

<table>
<thead>
<tr>
<th>Product</th>
<th>Sales Oil/Gas and Overboard Water</th>
<th>Theoretical Quantity</th>
<th>Material Balance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>1,438,544 stb</td>
<td>1,455,807 stb</td>
<td>-1.20%</td>
</tr>
<tr>
<td>Gas</td>
<td>2,746,575 mscf</td>
<td>2,827,599 mscf</td>
<td>-2.95%</td>
</tr>
<tr>
<td>Water</td>
<td>510,127 stb</td>
<td>496,404</td>
<td>3.10%</td>
</tr>
</tbody>
</table>

The material balance between the lease allocated quantities and the well level prorated well test volumes constitute Tier 2 performance of the offshore scenario, listed in Table B.25.
B.5 Production Measurement and Allocation System Implementation

B.5.1 General

The documentation for the Production Measurement and Allocation System designed and implemented for the offshore production scenario, per the requirements detailed in B.2 Identify PMAS Requirements, are consolidated in this section.

B.5.2 Measurement and Allocation Process Flow Diagram (MAPFD)

The MAPDF for the offshore production scenario is shown in Figure B.13. The offshore MAPFD show the following major points:

- Inflow quantities consisting of seven wells from three different leases, buy back oil and gas, and circulated oil and gas streams
- Commingling junctions at the IP, HP+LP, and LLP separators for the Wells 1-3 on Lease A, Wells 4-5 on Lease B, and Wells 6-7 on Lease C
- Measurement points are identified as numbered Designated Metering Points (DMP); DMPs are identified for all the separator gas and liquid outlets, the oil and gas export points, overboard water, buy back oil and gas points, fuel and flare gas points, and intra-process circulated oil and gas points

B.5.3 Measurement Equipment List for Allocation Inputs, Equipment Verification and Performance Specifications

Table B.26 and Table B.27 provide example equipment listing for liquid and gas allocation measurement points, respectively. The data includes device tag number, device type, make and model, configured UOM, operating range, published performance specifications, calibration procedure per industry standard, and recommended calibration frequency.
<table>
<thead>
<tr>
<th>Tag number</th>
<th>FT-1120</th>
<th>PT-1120</th>
<th>TT-1120</th>
<th>AE-1120</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type</td>
<td>TURBINE MTR</td>
<td>STATIC PRESS</td>
<td>TEMPERATURE</td>
<td>WIO ANALYZER</td>
</tr>
<tr>
<td>Manufacturer</td>
<td>METER CO</td>
<td>XMTR CO</td>
<td>XMTR CO</td>
<td>WIO DEVICE CO</td>
</tr>
<tr>
<td>Model</td>
<td>XYZ</td>
<td>XYZ</td>
<td>XYZ</td>
<td>XYZ</td>
</tr>
<tr>
<td>Unit of Measure</td>
<td>BBL</td>
<td>PSIG</td>
<td>DEG F</td>
<td>PERCENT WATER IN OIL</td>
</tr>
<tr>
<td>Range Min</td>
<td>3,400 BPD</td>
<td>0 PSIG</td>
<td>20 F</td>
<td>0%</td>
</tr>
<tr>
<td>Range Max</td>
<td>41,000 BPD</td>
<td>1000 PSIG</td>
<td>200 F</td>
<td>100%</td>
</tr>
<tr>
<td>Pipe Size</td>
<td>4 INCH</td>
<td>SIDE TAP IN 4 INCH PIPE</td>
<td>THERMOWELL IN 4 INCH PIPE</td>
<td>PROBE IN 4 INCH PIPE</td>
</tr>
<tr>
<td>Pressure rating</td>
<td>ANSI 300</td>
<td>ANSI 300</td>
<td>ANSI 300</td>
<td>ANSI 300</td>
</tr>
<tr>
<td>Nominal K-factor</td>
<td>1,260 PUL/BBL</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Linearity or Uncertainty</td>
<td>0.5%</td>
<td>0.15% URL 0.75 PSI</td>
<td>0.15% URL 0.3 °F</td>
<td>1.0%</td>
</tr>
<tr>
<td>Repeatability or stability</td>
<td>0.02%</td>
<td>0.2% URL PER YR</td>
<td>0.1% URL PER YR</td>
<td>0.1%</td>
</tr>
<tr>
<td>Calibration Procedure</td>
<td>API MPMS Ch. 20.2</td>
<td>API MPMS Ch. 21.2</td>
<td>API MPMS Ch. 21.2</td>
<td>MANUF. RECOMMENDATION</td>
</tr>
<tr>
<td>Calibration Frequency</td>
<td>MONTHLY NTE 60 DAYS</td>
<td>QUARTERLY NTE 120 DAYS</td>
<td>QUARTERLY NTE 120 DAYS</td>
<td>DAILY VALIDATION CALIBRATE AS NEEDED</td>
</tr>
</tbody>
</table>
Table B.27 Typical Gas Allocation Measurement Data

<table>
<thead>
<tr>
<th>DMP-102</th>
<th>IP SEPARATOR GAS OUTFLOW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tag number</td>
<td>FE-1020</td>
</tr>
<tr>
<td>Type</td>
<td>DC ORIFICE</td>
</tr>
<tr>
<td>Manufacturer</td>
<td>METER CO</td>
</tr>
<tr>
<td>Model</td>
<td>XYZ</td>
</tr>
<tr>
<td>Unit of Measure</td>
<td>CUBIC FEET</td>
</tr>
<tr>
<td>Range Min</td>
<td>PER DP</td>
</tr>
<tr>
<td>Rang Max</td>
<td>PER DP</td>
</tr>
<tr>
<td>Min. dia. ratio</td>
<td>0.2</td>
</tr>
<tr>
<td>Max. dia. ratio</td>
<td>0.6</td>
</tr>
<tr>
<td>Pipe Size</td>
<td>8 INCH</td>
</tr>
<tr>
<td>Pressure rating</td>
<td>ANSI 300</td>
</tr>
<tr>
<td>Linearity or Uncertainty</td>
<td>1.0%</td>
</tr>
<tr>
<td>Repeatability or stability</td>
<td>N/A</td>
</tr>
<tr>
<td>Calibration Procedure</td>
<td>API MPMS Ch. 14.3</td>
</tr>
<tr>
<td>Calibration Frequency</td>
<td>MONTHLY NTE 60 DAYS</td>
</tr>
</tbody>
</table>

B.5.4 Allocation Algorithm

The offshore scenario allocation algorithm is detailed in Section B.4 Allocation Process Definition of this annex. Offshore Scenario Allocation Tiers maps out the two-tier allocation setup for the offshore scenario. The reader is referred to Section B.4 in its entirety for details of the offshore allocation algorithm which includes the following information:

- Input data
- Logic
- Equations
- Calculation sequence
- Primary reported allocation results
B.5.5 Fluid Quality Verification

The following sections outline the minimum fluid quality verification plan for the offshore production scenario.

B.5.5.1 Liquid Sampling and Analysis

Liquid sampling and analytical procedures are performed in accordance with the following industry standards:

- API MPMS Ch. 8.2 – Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products

A composite liquid sample is obtained from a proportional to flow liquid sampler at the outlet of each separator on a monthly basis for allocation purposes. If a composite liquid sample becomes unavailable at any time, the shrink and flash gas factors determined from previous accepted composite sample can be used for the current allocation period.

If the proportional to flow sampler fails, the operator may use spot sample in lieu of a composite sample, but not to exceed 90 days. The composite sampler is to be remediated and brought back online in 90 days or less.

The single phase separator liquid composition is analysed by using a single-stage flash process to determine the gas-oil ratio (GOR). The flash gas and residual liquid compositions are determined by gas and liquid (simulated distillation) chromatography. The composite liquid composition is determined mathematically from the phase compositions and GOR.

An extended gas analysis to C9+ fraction of the flash gas and an extended liquid analysis to C36+ of the residual liquid are performed. The hydrocarbon plus fractions molecular weight and density are reported.

The quality of the liquid sample is impacted by two major factors: (1) the sampling process and (2) the analytical process. The composite liquid composition and fluid properties are also influenced by the well alignment and relative rates during an allocation period. The liquid sample acceptance criteria are based on the composition and fluid properties of the source fluids.

B.5.5.2 Gas Sampling

Gas sampling and analytical procedures are performed in accordance with the following industry standards:

- API MPMS Ch. 14.1 – Collecting and Handling of Natural Gas Samples for Custody Transfer, 6th ed., Feb 2006
- GPA 2261-13 – Analysis of Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,
- GPA 2145-16 – Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Natural Gas Liquids Industries, 2016 rev.

A composite gas sample is obtained from a proportional to flow gas sampler at the outlet of each separator on a monthly basis for allocation purposes. If a composite gas sample becomes unavailable at any time, the gas composition and PVT properties determined from previous accepted composite sample can be used for the current allocation period.

If the proportional to flow sampler fails, the operator may use spot sample in lieu of a composite sample, but not to exceed 90 days. The composite sampler is to be remediated and brought back online in 90 days or less.
The gas composition is analysed to C7+ fraction, non-hydrocarbon and hydrocarbon components including isomers to pentane, and lumped hexanes. Gross heating value, relative density and compressibility are reported on both water saturated and dry gas bases.

The quality of the gas sample is impacted by two major factors: (1) the sampling process and (2) the analytical process. The composite gas composition and fluid properties are also influenced by the well alignment and relative rates during an allocation period. The gas sample acceptance criteria are based on the composition and fluid properties of the source fluids.

**B.5.6 Data Handling and Storage**

The data gathering, handling, processing, transmission and storage for production scenario in this annex is typical of most offshore operations.

Field devices communicate with the platform ICSS (integrated control and safety system) via OPC tags. The real time data from every field device in the facility are stored redundantly on separate database called historian, located offshore and onshore.

Measurement and allocation field data are pulled from the historian and stored in a dedicated PMAS data server. Manual input of laboratory and field technician data interface are provided by the server. Production analysts access data from the server and generate all the PMAS reporting requirements. Figure B.16 shows the Offshore PMAS data handling architecture.

![Figure B.16 PMAS Data Handling Architecture](image)

**B.5.7 Phase Behavior Calculation Basis**

The PVT input data for the offshore allocation scenario includes the following parameters:

- Separator oil shrinkage factor
- Separator oil flash gas factor
Separator gas volume factor
Separator gas condensate-gas ratio (CGR)
Produced water volume factor

All the above parameters can be measured analytically in a PVT laboratory from separator oil, gas and water samples obtained for allocation purposes.

In this worked example scenario, laboratory analysis of separator oil sample for the period provided shrinkage and flash gas factors used in the allocation.

The separator gas CGR was calculated with an Equation of State (EoS) using the composition of the separator gas sample up to C7+, determined from a gas chromatograph. The separator gas remained in single-phase at standard conditions, with a cricondentherm well below 60°F. The outcome was independent of the EoS used and arbitrary breakdown of the C7+ fraction.

Having determined the separator gases to not undergo phase change at standard conditions, the gas volume factor was calculated from

\[ B_g = 0.0282793 \frac{ZT}{p} \frac{cf}{scf} \]  

(B-30)

Where:

- \( B_g \)  
  gas volume factor, cf/scf
- \( Z \)  
  gas compressibility factor at separator conditions
- \( T \)  
  separator temperature, °R
- \( p \)  
  separator pressure, psia

Equation (B-30) assumes the gas compressibility factor is unity at standard conditions. Alternatively, the compressibility factors can be calculated at both standard and separator conditions using and EoS.

Note that the use of Equation (B-30) is predicated on no phase change with the gas composition from separator to standard conditions. If phase change occurs, then \( B_g \) should be determined analytically.

B.5.8 Well Testing Application Basis

The prorated well oil, gas and water volumes were obtained from periodic well testing. All periodic well tests were are conducted in accordance with API MPMS Ch. 20.5.

B.5.9 Contingency Plan

Offshore facility OPERATOR will notify non-operating partners of any abnormal operating conditions, resulting contingency measure/s adopted, or any findings regarding measurements, fluid samples, allocation process, or unplanned operating events that raises concern on the equitable allocation of production. OPERATOR will submit a remediation plan and a reallocation strategy, if necessary, within 30 days of the adoption of a contingency. Remediation will be completed NTE 90 days after the submission of a remediation plan.
### Table B.28 Contingency Plan

<table>
<thead>
<tr>
<th>CP No</th>
<th>Situation</th>
<th>Contingency Plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>CP1</td>
<td>Pressure and temperature transmitters</td>
<td>In the event of pressure or temperature instrument failure during part of the allocation period, available and acceptable values recorded prior to failure will be used to represent the said period. If no valid data is available for the allocation period, OPERATOR will use valid data at analogue operating conditions from the closest previous allocation period.</td>
</tr>
</tbody>
</table>
| CP2   | Gas or liquid allocation meters        | If a gas or liquid allocation meter or their ancillary devices are out of service, or determined to provide inaccurate readings resulting in mismeasurement, OPERATOR will use, depending on availability, the appropriate of the following methods to determine produced quantities:  
1) Correct calibration error and apply mismeasurement handling policy  
2) Use producing separator gas-oil ratio representative of recent well rates and alignment (assuming reliable gas or liquid measurement is available)  
3) Well prorated volumes based on well tests |
| CP3   | Secondary gas or liquid meters (flare, fuel, and circulation meters) | If a secondary gas or liquid meter or their ancillary devices are out of service, or determined to provide inaccurate readings resulting in mismeasurement, OPERATOR will use, depending on availability, the appropriate of the following methods to determine volumetric quantities:  
1) Alternative ICSS system data  
2) Correct calibration error and apply mismeasurement handling policy  
3) Last applicable daily volume  
4) Engineering estimate  
5) Virtual metering estimate |
<p>| CP4   | Inline Water Cut Analyser             | If water cut analyser is found to be providing erroneous readings, available and acceptable readings will be utilized. If water cut analyser fails, OPERATOR will use spot samples and use shakeout, obtained twice daily at a minimum, to determine field water cut. The field water cut will be adjusted to metering conditions using Equation (16), Section 6.3.4.5 of API MPMS Ch. 20.5 |
| CP5   | Liquid composite sampler              | If composite liquid sample is not available for the current allocation period, the most recent and acceptable liquid sample analysis will be used for the current allocation period. If the proportional-to-flow composite sampler are determined to operate improperly, or has failed, spot samples will be taken to determine liquid properties for allocation purposes. Liquid properties determined from spot samples will be accepted if they fall within the range of the fluid sources. If not, the last valid set of properties will be used for the current allocation period. |</p>
<table>
<thead>
<tr>
<th>CP No</th>
<th>Situation</th>
<th>Contingency Plan</th>
</tr>
</thead>
</table>
| CP6   | Gas composite sampler            | If composite gas sample is not available for the current allocation period, the most recent and acceptable gas sample analysis will be used for the current allocation period.  
If the proportional-to-flow composite sampler are determined to operate improperly, or has failed, spot samples will be taken to determine gas properties for allocation purposes.  
Gas properties determined from spot samples will be accepted if they fall within the range of the fluid sources. If not, the last valid set of properties will be used for the current allocation period. |
| CP7   | Loss of System Data              | If the loss of totalized volumetric data occurs from any or all sources including flow computers, PLC, ICSS, or the data historian, and no redundant data is available, OPERATOR will use hourly rates obtained from the data historian for the balance of the allocation period after the discovery of data loss. |
| CP8   | Unplanned or unusual operational circumstances | Unplanned operational events including, but not limited to: (1) loss of communications, (2) system or local PLC/controller malfunctions, (3) power loss, (4) weather related shut-down and start-ups, may necessitate a deviation from the PMAS process. OPERATOR will document alternative allocation methodologies utilized, the time such alternative methods were in-place, provide an assessment of potential mis-allocation, and provide recommendation for reallocation, if necessary. |

**B.6 Operate and Manage PMAS**

**B.6.1 General**

All pertinent PMAS design and operational documentation is kept electronically in a secured file system. This set of files and data is referred to as the PMAS manual and contains the following types of data. Table B.29 shows the elements of a Measurement Manual.

**Table B.29 PMAS Measurement Manual**

<table>
<thead>
<tr>
<th>Section</th>
<th>Topic</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic Design</td>
<td>Process flow</td>
<td>• Measurement and allocation process flow diagram (MAPFD)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Relevant P&amp;ID pages</td>
</tr>
<tr>
<td></td>
<td>Allocation logic description</td>
<td>• Inputs and output parameters,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Equations,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Calculation sequence</td>
</tr>
<tr>
<td></td>
<td>Data handling and storage</td>
<td>• End device registers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Control system registers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Data historian tags</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• PMAS data base tags</td>
</tr>
<tr>
<td>Equipment and</td>
<td>Equipment specifications</td>
<td>• See tables Table B.26 and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Table B.27 for an example</td>
</tr>
</tbody>
</table>
Section | Topic | Contents
--- | --- | ---
Procedural Data | Procedures | • Gas and liquid sampling and analysis (see Fluid Quality Verification)
 |  | • Equipment validation and calibration procedures
 |  | • Laboratory audit procedures
KPIs and Tolerance Levels | Material Balances | • See tables Table B.24, Table B.25 for an example
 | Fluid properties variances | • API Gravity
 |  | • Water cut
 |  | • Shrinkage factors
 |  | • Flash factors
 |  | • Gas energy content
 | Equipment | • Meter factor variances
 |  | • XMTR as found as left
 |  | • WIO analyzer variances
Reporting | Reports | • Monthly measurement and allocation reports (MMAR)
 |  | • KPI data for past 12 months
 |  | • Out of tolerance performance reports
 |  | • Annual PMAS review report
 |  | • PMAS management of change (MOC) documents
Performance Management | Contingency Plan | See Table B.28 Contingency Plan
 | Out-of-tolerance performance resolution plan | • Specific roles and responsibilities of the staff members
 |  | • Data and causal analysis
 |  | • Recommendation and data reconciliation
 |  | • Modifications (MOC)

B.6.2 Performance Capability Assessment

Performance capability is a combination of the equipment or procedural base uncertainty, accuracy, or variability and the effects of the fluid properties and flowing conditions. It is an assessment as opposed to a calculation. Some technical judgement and operational knowledge is usually needed to come to a fair assessment of the performance expectation for any given situation. Table B.30 is an example of the performance expectation, which is used to set the out-of-tolerance limits for material balance. This example shows the capability assessment results for a liquid and gas metering point. The assessment considers both equipment specification and the in-situ effects such as flow velocity, variability in water cut, effects of low level gas carry under or low level liquid carry over, etc. This capability assessment does not consider the effects of high level of gas carry under or liquid carry over, which can cause significant larger errors.

<table>
<thead>
<tr>
<th>TAG NO</th>
<th>EQ-TYPE</th>
<th>MAKE MODEL</th>
<th>CURRENT CONDITIONS</th>
<th>RANGE</th>
<th>PERFORMANCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>DMP-112</td>
<td>IP separator liquid metering</td>
<td>Current conditions: 10MBOD, 25% w/ 425 PSIG, 105F</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FT-1120</td>
<td>Turbine meter</td>
<td>ABC Co</td>
<td>8.6 MBPD</td>
<td>86 MBPD</td>
<td>0.5%</td>
</tr>
<tr>
<td>FA-1120</td>
<td>WIO Analyzer</td>
<td>ABC Co</td>
<td>0</td>
<td>100</td>
<td>2%</td>
</tr>
<tr>
<td>PT-1220</td>
<td>Static Pressure</td>
<td>ABC Co</td>
<td>0 PSI</td>
<td>1000 PSI</td>
<td>0.25%</td>
</tr>
<tr>
<td>TT-1220</td>
<td>Temperature</td>
<td>ABC Co</td>
<td>20 F</td>
<td>200 F</td>
<td>0.05%</td>
</tr>
</tbody>
</table>

Performance capability range: 2.1% - 4.5%
B.6.3 Review and Modifications

A review of the offshore PMAS is conducted at the end of the first quarter of the calendar year, in accordance with Section 9.3 of this standard. Modifications to the offshore PMAS, resulting from review findings or new production coming into the facility via tie-backs, will be documented on an MOC system and in accordance with Section 9.4 of this standard.

B.6.4 Performance Monitoring and Reporting

Key Performance Indicators (KPI) are measurable parameters that provide an indication of the effectiveness of a process in achieving equitable allocation of production to all parties. For the offshore production scenario, the critical success factors to achieve equitable allocation of sales products are:

- Material balance is realized between all inlet, outlet, consumed and stored streams
- Instruments and analysers are calibrated on schedule and pass acceptance criteria
- Allocation meters are proven on schedule and pass acceptance criteria
- Fluid samples are obtained on schedule and are representative of the commingled stream over an allocation period
- Commingled fluid compositions are within bounds of source fluids composition and well alignment over an allocation period
- Commingled fluid properties are within range of source fluids

The KPIs covered in this section assume the process equipment performance levels are as intended. If this is not the case, for example, when large gas-carry under or liquid-carry over occurs due to inefficient phase separation, then the above KPIs may provide unreliable results.

B.6.4.1 Facility Material Balance

Offshore facility OPERATOR will monitor and report system balances for each allocation period based on the Commercial Requirements outlined in Section B.2.2.2, and Equation (B.29). The following Tier 1 system balance factors are required to be within ±5%:

- Absolute deviation between the Net Sales Oil Metered Volume and the Facility Theoretical Oil Volume, FTOV
- Absolute deviation between the Net Sales Gas Metered Volume and the Facility Theoretical Gas Volume, FTGV
- Absolute deviation between the Overboard Water Metered Volume and the Facility Theoretical Water Volume determined from the net oil analyzers, FTWV

If any of the three facility material balance factors exceed ±5 % in an allocation period, OPERATOR will perform an investigation to determine the cause of the imbalance. If the same balance factor exceeds the limit in any two consecutive months, or three months in a twelve month period, OPERATOR will perform and investigation to determine the root cause of the imbalance and implement corrective action. Upon completion of the

---

<table>
<thead>
<tr>
<th>DMP-112 IP separator gas metering</th>
<th>Current conditions: 100MMSCFD 425 PSIG, 105F</th>
</tr>
</thead>
<tbody>
<tr>
<td>FE-1020</td>
<td>DC-ORIFICE</td>
</tr>
<tr>
<td>DP-1020</td>
<td>DP XMTR</td>
</tr>
<tr>
<td>PT-1020</td>
<td>SP XMTR</td>
</tr>
<tr>
<td>TT-1020</td>
<td>TEMP XMTR</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>
investigation, OPERATOR will issue a Non-Compliance Report (NCR) to all non-operating parties along with a corrective action plan.

The following Tier 2 balance factors are required to be within ±8%:

- Absolute deviation between Lease Allocated Sales Oil Volume and the Lease Total Prorated Oil Volume based on well test
- Absolute deviation between Lease Allocated Sales Gas Volume and the Lease Total Prorated Gas Volume based on well test
- Absolute deviation between Lease Allocated Overboard Volume and the Lease Total Prorated Water Volume based on well test

If the tier 2 tolerance limit is exceeded, the owners of Lease B wells, which vary in ownership, will meet and agree any related actions or corrections.

### B.6.4.2 Instrument and Analyzer Maintenance

Equipment maintenance routine for instruments and analyzers is based on the company’s maintenance management software system. For each piece of equipment the maintenance management system lists pertinent information. For example, Table B.31 shows a typical report for an instrument that is past due.

#### Table B.31 Typical Maintenance Report

<table>
<thead>
<tr>
<th>Asset / Facility Name</th>
<th>Offshore Platform 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tag No</td>
<td>PT-1220</td>
</tr>
<tr>
<td>Equipment Type</td>
<td>Pressure Transmitter</td>
</tr>
<tr>
<td>Equipment Name</td>
<td>Static pressure – IP Separator – Oil Meter</td>
</tr>
<tr>
<td>Procedure No</td>
<td>SOP-105</td>
</tr>
<tr>
<td>Procedure Name</td>
<td>Pressure transmitter validation / calibration</td>
</tr>
<tr>
<td>Equipment Status</td>
<td>Active</td>
</tr>
<tr>
<td>Priority Level</td>
<td>3</td>
</tr>
<tr>
<td>Previous Date</td>
<td>15-NOV-2016</td>
</tr>
<tr>
<td>Today’s Date</td>
<td>29-JAN-2017</td>
</tr>
<tr>
<td>Schedule Date</td>
<td>ASAP</td>
</tr>
<tr>
<td>Frequency Limit (Days)</td>
<td>60</td>
</tr>
<tr>
<td>Days in use</td>
<td>75</td>
</tr>
<tr>
<td>Alarm Statement</td>
<td>PAST DUE</td>
</tr>
</tbody>
</table>

As an example, the technician reports referred to in the maintenance management system contain the detailed information necessary to document the activity and the results.
B.6.4.3 Fluid Sample Quality Assurance

Fluid samples obtained from the offshore facility are transported, received and stored in a third party laboratory site. OPERATOR will review laboratory standard operating procedure (SOP) documentation for the following:

- Sample Receipt and Handling Procedure – this document describes the steps to receive, handle and process samples that arrive at the receiving dock prior to transfer to the laboratory for analysis. It includes the sample check-in process, verification of documentation, and proper handling. For the offshore example, the following items are verified: (1) shipment documentation, (2) sample quantity and (3) testing requested.

- Sample Validation Procedure – this document describes the steps required to accept a sample as representative of the fluid source and fit-for-purpose for the analyses. For the offshore example, the following steps constitute the initial verification: (1) Samples are placed in heating chamber and heated at or above sampling temperature for a minimum of 6 hours, (2) verify the pressure of the cylinder to be within ±5 psi of the sampling pressure.

B.6.4.4 Fluid PVT Properties Quality Assurance

Fluid samples are analyzed in the laboratory to determine PVT properties listed in Section B.5.7 of this document. In the offshore example, the following steps are taken to assure the PVT properties used in the allocation process are representative of the source fluids. The steps include: (1) gas and liquid compositions are within the trend of historical production profile, (2) test if separator gas and liquid samples are in equilibrium, (3) test if PVT properties are within the bounds of the source fluids.

B.6.5 Out-of-Tolerance Performance Management

B.6.5.1 Roles and Responsibilities

Table B.32 shows a RACI type chart that defines the team and the respective roles and responsibilities regarding the management of out-of-tolerance PMAS performance. Keep in mind that the position titles will be specific to the organization and company. The RACI acronym stands for Responsible, Accountable, Contributor, and Informed.
<table>
<thead>
<tr>
<th>Position</th>
<th>Role</th>
<th>Responsibilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations Manager (e.g. OIM, AOM, etc.)</td>
<td>A</td>
<td>Accountable for providing oversight, resources of time, access to facility, personnel, budget allowances.</td>
</tr>
<tr>
<td>Measurement Supervisor</td>
<td>R</td>
<td>Responsible to lead causal analysis and conclusions including recommendations and relevant modifications to the PMAS (MOC)</td>
</tr>
<tr>
<td>Maintenance Supervisor</td>
<td>C</td>
<td>Contributor via equipment maintenance</td>
</tr>
<tr>
<td>Safety Supervisor</td>
<td>C</td>
<td>Contributor via safe operations</td>
</tr>
<tr>
<td>Measurement Engineer</td>
<td>C</td>
<td>Contributor for technical support, data analysis, recommended modifications</td>
</tr>
<tr>
<td>Measurement Tech</td>
<td>C</td>
<td>Contributor to assist in additional sampling, testing, and calibrations work</td>
</tr>
<tr>
<td>Production Accounting</td>
<td>I</td>
<td>Informed of suspected mismeasurements and reconciled data changes</td>
</tr>
<tr>
<td>Production Engineer</td>
<td>I</td>
<td>Informed of suspected mismeasurements and reconciled data changes</td>
</tr>
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</tr>
<tr>
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</tr>
<tr>
<td>B.17</td>
<td>Example As Found/As Left Report</td>
<td>134</td>
</tr>
</tbody>
</table>
Annex C
(informative)

Example Analysis for Establishing Thermodynamic Paths and PVT Parameter Determination for Liquid and Gas Hydrocarbons

The following examples are merely examples for illustration purposes only. They are 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

When determining hydrocarbon PVT fluid properties applied to input quantities (oil shrinkage factor, \(SF\); gas correction factor, \(B_g\); flash gas factor, \(FF\); solution condensate-gas ratio, \(r_s\)) it is useful to develop diagrams of the thermodynamic processes associated with the PMAS liquid and gas hydrocarbons. Creating a P-T phase diagram illustrating the thermodynamic path between allocation point conditions and end point conditions for liquid and gas hydrocarbons can provide a preliminary qualitative indication on the effective magnitude of a PVT parameter (e.g., is a phase boundary such as a retrograde dew point curve crossed that might require determination of \(r_s\)). It is also useful to develop a block diagram showing the physical process that a quantity of liquid and gas hydrocarbon is subject to as it transits the thermodynamic path of the PMAS, particularly as a precursor for use in flash calculations and EOS modeling of PVT fluid properties.

This annex provides a procedure for applying a P-T phase diagram and physical process block diagram in the preliminary evaluation of both a liquid and gas hydrocarbon for establishing thermodynamic paths and PVT parameter determination.

C.2 Procedure

1) Provide a Characterization of the Hydrocarbon. Determine the hydrocarbon composition at allocation point conditions and identify an applicable VLE EOS that can be used to generate a P-T phase diagram.

   NOTE 1 Refer to API Draft Standard Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems for details on establishing hydrocarbon compositions for use in EOS phase behavior calculations.

   NOTE 2 Using an EOS previously tuned to match PVT fluid properties of the hydrocarbon typically can provide the most accurate P-T phase diagram.

2) Plot the P-T Phase Diagram. Using the EOS and hydrocarbon composition in commercially available software, plot the P-T phase diagram.

3) Identify the Thermodynamic Path from Allocation Point Conditions to End Point Conditions on the P-T Phase Diagram, Including Intermediate Thermodynamic Equilibrium Points. Plot the various P-T conditions from allocation point conditions to end point conditions (including intermediate thermodynamic equilibrium points) and qualitatively evaluate the magnitude of \(SF\), \(FF\), \(B_g\), and \(r_s\). For example, a thermodynamic path for a liquid hydrocarbon that transits the length of the phase envelope is an indication that the liquid hydrocarbon will evolve gas between allocation point conditions and end point conditions (i.e., an indication of volatility). Therefore, it would be anticipated that the quantification of the \(SF\) and \(FF\) is warranted for additional evaluation and potential use in the determination of theoretical quantities. Alternatively, a thermodynamic path for a gas hydrocarbon that crosses the dew point curve into the phase envelope is an indication that the gas hydrocarbon will condense liquids between allocation point conditions and end point conditions (i.e., an indication of retrograde
condensate). Thus, it would be anticipated that the quantification of the $B_g$ and $r_s$ is warranted for additional evaluation and potential use in the determination of theoretical quantities.

NOTE Recall that the intermediate thermodynamic equilibrium points correspond to major liquid/vapor separation stages. At each stage, liquid would be separated from gas, resulting in new liquid and gas hydrocarbon compositions and new P-T phase diagrams for each phase. Repeating the previous steps to generate separate P-T phase diagrams can be a useful exercise but is not required for the preliminary evaluation addressed in this annex.

4) Align a Physical Process Block Diagram with the P-T Phase Diagram. Illustrate a quantity of liquid or gas hydrocarbon as it moves along its respective thermodynamic path alongside the P-T phase diagram. This exercise can provide a useful visual representation of the process and reiterate the physical steps that would be used to define a flash calculation model for determination of PVT fluid properties.

C.3 Example Liquid Application

1) Provide a Characterization of the Hydrocarbon. Consider the following liquid hydrocarbon composition at an allocation point:

<table>
<thead>
<tr>
<th>COMPONENT</th>
<th>MOLE FRACTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen</td>
<td>0.00023</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
<td>0.00025</td>
</tr>
<tr>
<td>Methane</td>
<td>0.05536</td>
</tr>
<tr>
<td>Ethane</td>
<td>0.05308</td>
</tr>
<tr>
<td>Propane</td>
<td>0.08010</td>
</tr>
<tr>
<td>i-Butane</td>
<td>0.01848</td>
</tr>
<tr>
<td>n-Butane</td>
<td>0.05330</td>
</tr>
<tr>
<td>i-Pentane</td>
<td>0.02652</td>
</tr>
<tr>
<td>n-Pentane</td>
<td>0.04094</td>
</tr>
<tr>
<td>Hexanes</td>
<td>0.05945</td>
</tr>
<tr>
<td>Heptanes</td>
<td>0.06697</td>
</tr>
<tr>
<td>Octanes</td>
<td>0.07290</td>
</tr>
<tr>
<td>Nonanes</td>
<td>0.05878</td>
</tr>
<tr>
<td>Decanes +</td>
<td>0.41365</td>
</tr>
</tbody>
</table>

NOTE Hexanes, heptanes, octanes, nonanes and decanes + are pseudo-components specifically applied to this example composition.

For this example, a Peng Robinson EOS is used.
2) *Plot the P-T Phase Diagram.* Using a commercially available flash simulator, the following P-T phase diagram is derived using the hydrocarbon composition and the Peng Robinson EOS:

![P-T Phase Diagram](image)

In addition to the phase envelope for the liquid hydrocarbon, the plot includes the pressure and temperature conditions for a hypothetical liquid production process. The allocation point corresponds to an inlet separator, intermediate point conditions #1 corresponds to an equilibrium stage of separation after the inlet separator (e.g., a FWKO), and intermediate point conditions #2 is a final equilibrium stage of separation prior to storage (e.g., a bulk oil treater). End point conditions corresponds to a storage tank (e.g., a dry oil tank).

3) *Identify the Thermodynamic Path from Allocation Point Conditions to End Point Conditions on the P-T Phase Diagram, Including Intermediate Thermodynamic Equilibrium Points.* The previous P-T phase diagram is expanded to further illustrate the thermodynamic path of the oil from allocation point conditions to end point conditions:
The figure depicts the actual thermodynamic path the oil transits between allocation point conditions and end point conditions via the intermediate points, as illustrated by the multistage flash thermodynamic path. The figure also demonstrates the thermodynamic path that would be followed by flashing the oil from allocation point conditions to end point conditions via a single-stage flash. As reference, the bubble point curves for the resulting oils after flash at equilibrium conditions are included in the diagram. (Recall that at each equilibrium point a new hydrocarbon liquid composition is generated following flash of the liquid to gas.)

4) **Align a Physical Process Block Diagram with the P-T Phase Diagram.** A physical process block diagram is developed for both a multistage flash and single-stage flash scenario and aligned with the P-T phase diagram per the numbered labels (1, 1a, 1b, 2, 3):
The physical process block diagram provides a separate qualitative description of the production process and thermodynamic paths and depicts the evolution of gas as the hydrocarbon liquid is flashed between allocation point conditions and end point conditions. The block diagram also illustrates how $SF$ and $FF$ are derived.

C.4 Example Gas Application

1) **Provide a Characterization of the Hydrocarbon.** Consider the following gas hydrocarbon composition at an allocation point:
<table>
<thead>
<tr>
<th>COMPONENT</th>
<th>MOLE FRACTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen</td>
<td>0.0262</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
<td>0.0112</td>
</tr>
<tr>
<td>Methane</td>
<td>0.8084</td>
</tr>
<tr>
<td>Ethane</td>
<td>0.055</td>
</tr>
<tr>
<td>Propane</td>
<td>0.0228</td>
</tr>
<tr>
<td>i-Butane</td>
<td>0.0069</td>
</tr>
<tr>
<td>n-Butane</td>
<td>0.009</td>
</tr>
<tr>
<td>i-Pentane</td>
<td>0.0041</td>
</tr>
<tr>
<td>n-Pentane</td>
<td>0.0045</td>
</tr>
<tr>
<td>C6</td>
<td>0.0065</td>
</tr>
<tr>
<td>Benzene</td>
<td>0.0017</td>
</tr>
<tr>
<td>Toluene</td>
<td>0.0012</td>
</tr>
<tr>
<td>Xylenes</td>
<td>0.0009</td>
</tr>
<tr>
<td>C7</td>
<td>0.0052</td>
</tr>
<tr>
<td>C8</td>
<td>0.0053</td>
</tr>
<tr>
<td>C9</td>
<td>0.0037</td>
</tr>
<tr>
<td>C10</td>
<td>0.0042</td>
</tr>
<tr>
<td>C11</td>
<td>0.0035</td>
</tr>
<tr>
<td>C12</td>
<td>0.0027</td>
</tr>
<tr>
<td>C13</td>
<td>0.0027</td>
</tr>
<tr>
<td>C14</td>
<td>0.0022</td>
</tr>
<tr>
<td>C15 – C19</td>
<td>0.0071</td>
</tr>
<tr>
<td>C20+</td>
<td>0.0053</td>
</tr>
</tbody>
</table>

NOTE C6, C7, C8, C9, C10, C11, C12, C13, C14, C15 – C16, and C20+ are pseudo-components specifically applied to this example composition.

For this example, a Peng Robinson EOS is used.

2) *Plot the P-T Phase Diagram.* Using a commercially available flash simulator, the following P-T phase diagram is derived using the hydrocarbon composition and the Peng Robinson EOS:
In addition to the phase envelope for the gas hydrocarbon, the plot includes the pressure and temperature conditions for a hypothetical gas production process. The allocation point corresponds to an inlet separator, and intermediate point conditions corresponds to an equilibrium stage of separation after the inlet separator (e.g., a knockout drum). End point conditions corresponds to the export point.

3) **Identify the Thermodynamic Path from Allocation Point Conditions to End Point Conditions on the P-T Phase Diagram, Including Intermediate Thermodynamic Equilibrium Points.** The previous P-T phase diagram is expanded to further illustrate the thermodynamic path of the gas from allocation point conditions to end point conditions:
The figure depicts the actual thermodynamic path the gas transits between allocation point conditions and end point conditions via the intermediate point, as illustrated by the multistage flash thermodynamic path. The figure also demonstrates the thermodynamic path that would be followed by flashing the gas from allocation point conditions to end point conditions via a single-stage flash. The dew point curves for the resulting gases after flash at equilibrium conditions are included in the diagram. Note that the allocation point gas crosses the phase boundary, indicating that liquid hydrocarbon condenses out of the gas. To what extent the hydrocarbon gas condenses requires additional analysis and quantification of $r_x$. Also note that relative to intermediate point conditions (i.e., the dew point curve of the intermediate gas), the gas remains in the gas phase at end point conditions (i.e., no additional liquid condenses).

4) **Align a Physical Process Block Diagram with the P-T Phase Diagram.** A physical process block diagram is developed for both a multistage flash and single-stage flash scenario and aligned with the P-T phase diagram per the numbered labels (1, 1a, 2, 3):
The physical process block diagram provides a separate qualitative description of the production process and thermodynamic paths and depicts the condensation of liquid as the hydrocarbon gas is flashed between allocation point conditions and end point conditions. The block diagram also illustrates how $B_g$ and $r_s$ are derived.

**NOTE 1** The condensed liquid hydrocarbon follows the thermodynamic path of the associated liquid production process.

**NOTE 2** The gas quantity at standard conditions includes gas evolved from the condensed liquid as the liquid follows the thermodynamic path of the associated liquid production process.

$Q_{g,sc}$ quantity of gas hydrocarbon at standard conditions
$Q_{g,apc}$ quantity of gas hydrocarbon at allocation point conditions
$Q_{g,e pc}$ quantity of gas hydrocarbon at end point conditions
$Q_{g,ipc}$ quantity of gas hydrocarbon at intermediate point conditions
$Q_{o,ipc}$ quantity of liquid hydrocarbon at intermediate point conditions
$Q_{o,sc}$ quantity of liquid hydrocarbon at standard conditions
$Q_{o,epc}$ quantity of liquid hydrocarbon at end point conditions
$B_g$ gas correction factor
$r_s$ solution condensate-gas ratio
Annex D  
(informative)

Example Tank Inventory Calculations

The following examples are merely examples for illustration purposes only. They are 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.

D.1 General

This annex provides example calculation for a First In First Out (FIFO) process and for an Available to Sales process to determine changes in inventory.

D.2 First In First Out (FIFO)

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TOTAL E + TOTAL D - TOTAL C = TOTAL B

\[
\frac{\text{TOTAL B}}{\text{TOTAL A}} \times \text{SOURCE}(i) \times A = \text{SOURCE}(i) \times B
\]

\[
\frac{\text{TOTAL D}}{\text{TOTAL B}} \times \text{SOURCE}(i) \times B = \text{SOURCE}(i) \times D
\]

\[
\text{SOURCE}(i) \times A + \text{SOURCE}(i) \times C - \text{SOURCE}(i) \times D = \text{SOURCE}(i) \times E
\]

D.3 Available to Sales

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TOTAL F + TOTAL E - TOTAL C = TOTAL B

\[
\frac{\text{TOTAL B}}{\text{TOTAL A}} \times \text{SOURCE}_A = \text{SOURCE}_B
\]

\[
\text{SOURCE}_D = \text{SOURCE}_B + \text{SOURCE}_C
\]

\[
\frac{\text{TOTAL F}}{\text{TOTAL D}} \times \text{SOURCE}_D = \text{SOURCE}_F
\]

\[
\text{SOURCE}_B + \text{SOURCE}_C - \text{SOURCE}_E = \text{SOURCE}_E
\]
Annex E
(informative)

Shrinkage Determination Factor (Field)

E.1 General
The procedure below describes how to determine the shrinkage factor for a hydrocarbon liquid. The sample captured for shrinkage determination should represent the liquid at actual conditions.

E.2 Procedure
1. Determine the temperature of the sampled fluid when the sample is obtained, and record the pressure.
2. With the charged sample cylinder in an upright position, slowly bleed the sample into a clear calibrated graduated cylinder that is open to atmospheric pressure. The graduated cylinder should be large enough to contain the entire sample.
3. Allow the sample to stabilize until no gas bubbles are visible.
4. Record the total volume of the sample remaining in the graduated cylinder. Record the temperature of the sample.
5. If water is present in the final sample, determine its water cut using a recognized method.
6. Obtain a sample of water free hydrocarbon and determine its API gravity at 60°F or density in kg/m³ at 15°C.
7. Compute the shrinkage factor using the following equation:

\[ SF = \frac{(V_f - (V_f \times X_w)) \times CTL_f}{(V_i - (V_i \times X_w)) \times CTL_i} \]

Where:
- \( V_f \) = total volume of final sample in the graduated cylinder.
- \( V_i \) = total volume of initial sample in the sample cylinder.
- \( X_w \) = volume fraction of water in the final sample.
- \( CTL_f \) = volume correction factor based on temperature of final sample.
- \( CTL_i \) = volume correction factor based on temperature during sampling.
Annex F
(informative)

Volume Correction Factor for the Effect of Temperature and Pressure on Produced Water

F.1. General

Liquid densities are a function of temperature and pressure. Because the thermal coefficient of expansion and the bulk modulus for oil and water are different, the change in density of water and oil will be different for a given change in pressure and temperature. The bulk modulus of water is 1.5 to 2 times greater than oil while the thermal coefficient of expansion of oil is 4 to 5 times greater than water. These differences will always drive a greater density change in the oil. When the initial pressure and temperature are both greater than or less than the final pressure and temperature, the effects of pressure and temperature are counteracting.

When a quantity fraction of water in a sample of allocation source liquid is evaluated at atmospheric pressure and temperature a volume correction factor, CTPLW, is needed to determine the water fraction at source conditions. Conversely, when a water volume is determined at measured conditions, the same volume correction factor can be applied to determine the water volume at standard conditions. The CTPLW is calculated using the following procedures:

F.2. CTPLW Customary Units

\[ CTPLW = \frac{P_t}{P_{60}} \]  \hspace{1cm} (Eqn. F1)

Where:
- \( P_t \) = density of produced water at temperature \( t \) (°F) and pressure \( p \) (psia) in kg/m³.
- \( P_{60} \) = density of produced water at 60°F and 14.696 psia in kg/m³.

\[ CTPLW = CTLW \times CPLW \]  \hspace{1cm} (Eqn. F2)

Where:
- \( CTLW \) = Volume correction factor to account for change in temperature.
- \( CPLW \) = Volume correction factor to account for change in pressure.

\[ CTLW = 1 - (9.177 \times 10^{-5} t + 1.442 \times 10^{-6} t^2) \]  \hspace{1cm} (Eqn. F3)

Where:
- \( t = ^\circ \text{F} - 60 \)

\[ CPLW = 1 + (3.4984 \times 10^{-6} - 1.2487 \times 10^{-8} t_s + 8.8523 \times 10^{-11} t_s^2) Dp \]  \hspace{1cm} (Eqn. F4)

Where:
- \( t_s = ^\circ \text{F} - 32 \)
- \( Dp = p - 14.696 \)
- \( p \) = pressure in psia

F.3. CTPLW Metric Units

\[ CTPLW = \frac{P_{t,p}}{P_{15}} \]  \hspace{1cm} (Eqn. F5)
Where:

\[ P_t = \text{density of produced water at temperature } t (^\circ \text{C}) \text{ and pressure } p \text{ (psia) in kg/m}^3 \]

\[ P_{15} = \text{density of produced water at } 15^\circ \text{F and } 101325 \text{ Pa in kg/m}^3 \]

\[ CTPLW = CTLW \times CPLW \quad \text{(Eqn. F6)} \]

Where:

\[ CTLW = \text{Volume correction factor to account for change in temperature.} \]

\[ CPLW = \text{Volume correction factor to account for change in pressure.} \]

\[ CTLW = 1 - (1.626 \times 10^{-4} d_t + 4.6 \times 10^{-5} d_t^2) \quad \text{(Eqn. F7)} \]

\[ dt = ^\circ \text{C} - 15 \]

\[ CPLW = 1 + (5.074 \times 10^{-10} - 3.26 \times 10^{-12} t_a + 4.16 \times 10^{-14} t_a^2) d_p \quad \text{(Eqn. F8)} \]

Where:

\[ t_a = \text{temperature in } ^\circ \text{C} \]

\[ d_p = p - 101325 \quad p = \text{absolute pressure in Pa (Pascals)} \]

F.4. Further Information

For further information on the determination of water volume correction factors see API MPMS Chapter 11.4.1 Density of Water and Water Volumetric Corrections for Water Calibration of Volumetric Provers

F.5. CTLW for high salinity water

The base density of the water can impact the thermal coefficient of expansion and the bulk modulus of water. When there is a large disparity in base water density/salinity (14 % salinity difference by weight) between source streams, a bias of up to 0.4 % could be introduced in the water volume calculation. When the base density of the produced water is greater than 999.016 kg/m\(^3\) at 60°F and 14.696 psia (999.102 kg/m\(^3\) and 101325 Pa), the following procedure can be used to determine CTLW. There is no procedure to account for the CPLW except as outlined above.

\[ CTLW = (P_t) I (P_{60}) \quad \text{(Eqn. F9)} \]

Where:

\[ P_t = \text{density of produced water at temperature } t (^\circ \text{F}) \text{ in kg/m}^3 \]

\[ P_{60} = \text{density of produced water at } 60^\circ \text{F in kg/m}^3 \]

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

\[ CTLW = 1 - (1.0312E-4 + 7.1568E-6 \times B) \times (d t) \]

\[ - (1.2701E-6 - 4.4641E-8 \times B) \times (d t)^2 \quad \text{(Eqn. F10)} \]
\[ + (1.2333 \times 10^{-9} - 2.2436 \times 10^{-11} \times B) \times (d_t)^3 \]

\[ B = \text{% salinity by weight. If } p_{60} \text{ is known, } B \text{ can also be calculated using the formula, } \]
\[ B = \frac{(P_{60} - 999.0)}{17.2} \]

\[ d_t = t - 60 \]

\[ = \text{water temperature in °F} \]

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

**F.6. High Salinity CTLw SI Units**

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

\[ CTL_w = \frac{(P_t)}{(P_{15})} \]  \hspace{1cm} (Eqn. F11)

Where:

\[ P_t = \text{density of produced water at temperature } t \text{ (°C) in kg/m}^3. \]

\[ P_{15} = \text{density of produced water at 15°C in kg/m}^3. \]

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

Where:

\[ CTL_w = 1 - (1.8562 \times 10^{-4} + 1.2882 \times 10^{-5} \times B) \times (d_t) \]

\[ - (4.1151 \times 10^{-6} - 1.4464 \times 10^{-7} \times B) \times (d_t)^2 \]

\[ + (7.1926 \times 10^{-9} - 1.3085 \times 10^{-10} \times B) \times (d_t)^3 \]

\[ B = \text{% salinity by weight. If } P_{15} \text{ is known, } B \text{ can also be calculated using the formula, } \]
\[ B = \frac{(P_{15} - 999.0)}{17.2}. \]

\[ d_t = t - 15 \]

\[ t = \text{Water temperature, in °C} \]

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


[4] API MPMS Chapter 3.6, Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems


[8] API MPMS Chapter 12.3 Volumetric Shrinkage resulting from Blending Light Hydrocarbons with Crude Oils

[9] API MPMS Chapter 14.1, Collecting and Handling of Natural Gas Samples for Custody Transfer

[10] API MPMS Chapter 18.1, Measurement Procedures for Crude Oil Gathered From Small Tanks by Truck


[14] API RP 87, Field Analysis of Crude Oil Samples Containing from Two to Fifty Percent Water by Volume


[17] GPA 2145-09, Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry.


[19] API MPMS Chapter 10.4, Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Field Procedure)