Technical Specification

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Design and operation of allocation systems used in gas productions facilities

Conception et opération des systèmes d'allocation dans les installations de production de gaz

Reference number
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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO document should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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This document was prepared by Technical Committee ISO/TC 193, *Natural gas*, Subcommittee SC 3, *Upstream area*.

This first edition cancels and replaces ISO/TR 26762:2008, which has been technically revised.

The main changes compared to the previous edition are as follows:

— revision and update of flow and analysis measurement part;

— detailed description of all allocation methods;

— development of fluid property calculation and process simulation part;

— development of a specific uncertainty clause with examples;

— integration of well allocation part in addition to purely commercial allocation;

— extension of design considerations as well as operation considerations;

— incorporation of a specific clause on allocation audits.

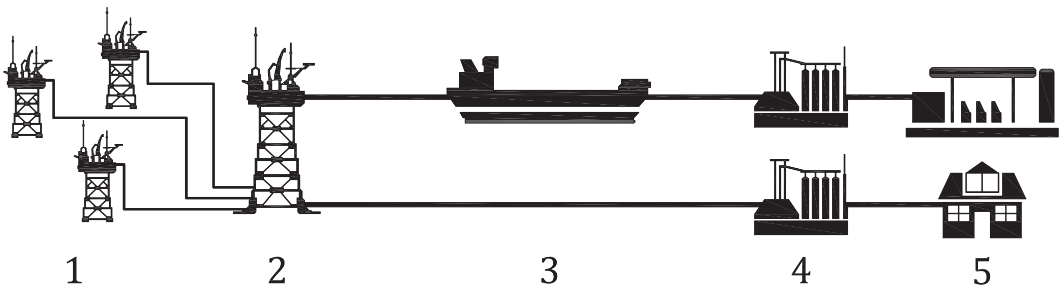
Any feedback or questions on this document should be directed to the user’s national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

Allocation is the procedure for sharing production and products belonging to different users of shared facilities when such production and products result from processing and transport of streams in a commingled way (Figure 1).

For instance, allocation is performed to attribute oil, gas and water production back to production wells when these wells are produced and processed in the same facilities. Correct well allocation has a high impact on reservoir management and cost related to well overhauls.

More critically, allocation of hydrocarbons and associated streams is performed when different licenses with different equity share are tied into a shared process facility, pipeline or plant. Allocation calculations are used to determine each license's and/or owner's allocated share of the outgoing new comingled stream(s) directed to the delivery/sales point. The allocated share in volume, mass or energy is required for gross company revenue, tariffs, duties, fees and taxes.



Key

1 wells production facility
2 processing facility
3 transportation cargo/pipeline
4 plant
5 market

Figure 1 — Schematic view of a typical allocation system

The intention is to conduct allocation in acceptable terms to ensure the license/owners receive their fair share of the comingled stream and that no parties experience unnecessary or unknown losses.

The allocation of gas and other products is a result of field development, technical design, investments and commercial negotiation and agreements. There are multiple combinations of allocation methods and calculations. Most of the allocation systems and hydrocarbon value realization chains are unique. As more fields and licenses are connected to common process facilities or transportation infrastructure, the complexity increases to ensure owners get a fair return on investment and production. Small bias to measurements over time can result in errors that represent large amounts of money. However, it can be too costly to invest in a low measurement uncertainty of a minor production stream. Cost-benefits and uncertainty analyses of the value chain are a good way to understand the cost of maximizing return on investment.

To design, evaluate, audit or operate an allocation system/method for gas and associated liquids, it is necessary to have competence within fluid thermodynamic properties, flow characteristics, gas treatment/processing, measurement, process simulation, sampling, allocation principles, uncertainty calculations and the value realization chain for the given application.

As sustainable computer systems are necessary to handle the allocation calculation on a regular basis and storing data securely, IT skills are also required.

This document comprises the most common or recommended allocation principles, systems, uncertainty, and calculation of possible losses, including some evaluation of risk for losses. Some clauses are directly derived from HM 96 developed by Energy Institute which very generously allowed ISO to use them.

Design and operation of allocation systems used in gas productions facilities

1 Scope

This document specifies how to design and operate allocation systems for gas production facilities.

It describes the most common types, principles and methods used for the allocation of gas and associated liquids. The objective is to provide an approach to current best practice in the oil and gas industry.

It applies to gas and liquid allocations to be performed in production, processing, transportation, storage and terminal installations dealing with natural gas and associated liquids as well as end products like sales gas, liquefied petroleum gas (LPG), liquefied natural gas (LNG), condensate and to some extend non-hydrocarbon gases like CO_2, H_2.

This document provides the minimum information needed to develop and implement allocation procedures and systems both for internal purposes (well allocation) and fiscal or commercial applications with different owners and stakeholders.

This document can be used to develop gas and liquid processing and transportation agreements and regulatory documents as well as to conduct audit of measurement and allocation systems.

It also introduces the areas of competence needed and the terminology used in the industry.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 5167 (all parts), *Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full*

ISO 10715, *Natural gas — Gas sampling*

ISO 14532, *Natural gas — Vocabulary*

HM 96, *Guidelines for the allocation of fluid streams in oil and gas production*

3 Terms and definitions

For the purposes of this document, the terms and definitions given in ISO 14532, HM 96 and the following apply.

ISO and IEC maintain terminology databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at https://www.electropedia.org/

3.1 Fluids

3.1.1
condensate-gas ratio
CGR
ratio of condensate to gas

Note 1 to entry: The condensate-gas ratio can be expressed on either a mass or a volume basis.

3.1.2
dry gas
gas in vapor phase containing no liquids.

Note 1 to entry: Gas is not necessarily only hydrocarbon but can contain other components such as CO_2, N_2, etc. There is no liquid entrainment and no liquid condensation is expected over the expected normal operating temperatures and pressures at the metering point

EXAMPLE Gas with a dew point of − 5 °C that is measured under conditions between 5 °C and 10 °C.

3.1.3
equation of state
EOS
mathematical expression that relates the composition, pressure and temperature of a fluid

Note 1 to entry: For an ideal gas, the equation of state is the ideal gas law. More complicated equations of state have been developed to model the behaviour of actual gases over a range of pressures and temperatures, e.g. Benedict, Webb, Rubin (BWR equation) and Soave, who modified Redlich and Kwong's Formula (SRK equation).

3.1.4
equilibrium gas
⟨dry gas⟩ at its dew point but without the presence of liquid condensation

Note 1 to entry: Any change in temperature or pressure can cause a change in state of the gas towards a dry gas or a wet gas.

Note 2 to entry: Separated at dew point.

Note 3 to entry: Typically gas at the outlet of a properly functioning separator.

3.1.5
equilibrium liquid
separated liquid at bubble point
hydrocarbon liquid at its equilibrium pressure and temperature, which does not contain any gas

Note 1 to entry: However, any further pressure or temperature change can cause gas to be released. True equilibrium liquid is very rare in gas-condensate processing as the dynamic nature of the processes does not allow sufficient time for liquids to reach equilibrium conditions.

3.1.6
gassy liquid
⟨two or three phases⟩ any mixture of hydrocarbon liquid and water at a pressure below its equilibrium pressure (bubble point) and where gas is present in the liquid mixture

Note 1 to entry: This typically occurs inside a separator or where the liquid is exposed to a pressure reduction, e.g. cavitation.

3.1.7
gas-oil ratio
GOR
ratio of produced gas flow rate to the produced oil (condensate) flow rate

Note 1 to entry: GOR is generally measured in standard units, e.g. cubic meters per cubic meter (standard cubic feet per barrel).

3.1.8
gas-condensate ratio
GCR
ratio of produced gas flow rate to the produced condensate flow rate

Note 1 to entry: The GCR is generally measured in standard units, e.g. cubic meters per cubic meter (standard cubic feet per barrel).

3.1.9
gas-liquid ratio
GLR
ratio of produced gas flow rate to the produced total liquid flow rate

Note 1 to entry: The GLR is generally measured in standard units, e.g. cubic meters per cubic meter (standard cubic feet per barrel).

3.1.10
gas volume fraction
GVF
ratio of produced gas flow rate to the produced fluid (gas plus liquid) flow rate

Note 1 to entry: The GVF is generally measured under actual conditions, e.g. cubic meters per cubic meter, and expressed as a fraction.

3.1.11
multiphase fluid
⟨oil and gas production⟩ mixture of the three phases: liquid hydrocarbon, water and gas

Note 1 to entry: Almost all fluids encountered in oil and gas production are multiphase fluids. There are broad categories of multiphase fluid, e.g. wet gas where the GVF is typically > 90 %; fluids from a wide range of oil wells where 5 % < GVF < 90 %; and low-GVF, “gassy" oils. “Multiphase fluid” is not a well-defined substance.

3.1.12
single-phase liquid
liquid at a pressure above its equilibrium pressure (bubble point)

EXAMPLE Liquid below the level of the outlet of a separator where static head (or booster pumps) increase(s) the pressure above the equilibrium pressure.

Note 1 to entry: The liquid can contain traces of water.

3.1.13
water fraction
volumetric fraction of water in the total fluid stream (water, liquid hydrocarbons and gas hydrocarbons), with all volumes determined at the same pressure and temperature

Note 1 to entry: Water fraction is often used in wet-gas applications.

Note 2 to entry: Water fraction can be expressed in mass fraction.

Note 3 to entry: Water fraction can be expressed in percentage.

3.1.14
wet gas
⟨two- or three-phase⟩ any mixture of gas and up to about 10 % by volume liquid hydrocarbon and/or water

Note 1 to entry: The mass ratio of gas to liquid varies significantly with pressure for a constant gas volume fraction. A convenient parameter to indicate the wetness of the gas is the Lockhart-Martinelli parameter .

3.2 Definitions for allocation systems

3.2.1
allocation process
calculation by which a quantity of products measured at a node is allocated to one or more contributing sources, fields or owners

Note 1 to entry: Allocation units are either volume, mass or energy.

3.2.2
attribution
process of calculating a final quantity for each allocation point based on its assigned substitution and allocated quantities

3.2.3
components
individual chemical compounds within a product stream

EXAMPLE 1 CH_4, methane, also designated C_1.

EXAMPLE 2 C_2H_6 ethane, also designated C_2.

3.2.4
data reconciliation
adjustment of measurement data to conform to balance constraints that can apply

Note 1 to entry: Data reconciliation uses statistical methods to ensure the weighted sum of the squares of the differences between the measurements and their revised values are minimized.

Note 2 to entry: The technique considers the uncertainties and gives more weight to measurements that are expected to be most accurate.

3.2.5
delivery point
final measurement point(s) where hydrocarbons leave a single allocation stage

3.2.6
energy
heat energy released when the gas or condensate is subject to combustion under specified conditions

Note 1 to entry: Energy can be expressed per unit mass, per unit (standard or normal) volume or per mole, at various reference temperatures and pressures, with or without the condensation energy of the water vapor formed during combustion. See ISO 6976 for further information.

3.2.7
entry point
entry of a stream into an installation

Note 1 to entry: Quantities associated with entry points can be measured or derived.

3.2.8
gas facilities
any installation receiving, processing, transporting or storing hydrocarbons for further natural gas production

3.2.9
products
any fluid marketable or not, derived from processing wet gas or gas like sales gas, liquefied petroleum gas and liquefied natural gas

Note 1 to entry: Gas products also include nonhydrocarbon liquid like CO_2 as well as associated liquids and condensed liquids like water and hydrocarbon condensates.

3.2.10
gas recovery factor
mass of gas obtained after processing divided by total hydrocarbon mass input

3.2.11
injection gas
gas injected into a field's reservoir to maintain reservoir pressure

Note 1 to entry: The gas is not specific to any one producing well, as is the case with lift gas. It is possible that the gas does not appear from production wells until years after injection has begun.

Note 2 to entry: The allocation of injection gas is usually different from the allocation of lift gas.

3.2.12
imbalance
physical difference between outputs and inputs corrected for any change in stock

3.2.13
mass component
total mass of a single chemical component within a stream, the total of all components being equal to the total mass delivered by that stream

3.2.14
node
any originating point to an allocation system or a point with two or more streams attached.

3.2.15
mismeasurement
process resulting in an erroneous quantity or quality value being recorded and entered into an allocation system

Note 1 to entry: The error in the value can be caused by faulty or incorrect equipment, incorrect configuration, or correction factors.

3.2.16
oil recovery factor
ORF
quantity of oil obtained after processing divided by total hydrocarbon input

Note 1 to entry: Usually defined by component.

3.2.17
shrinkage factor
volume or mass change of hydrocarbon liquids from upstream process to end-of-process conditions

Note 1 to entry: Change is generally reduction.

3.2.18
simulation model
process engineering model simulating processing facilities for the calculation of allocation parameters

Note 1 to entry: Like but not limited to recovery factors, volume conversion factors, fluid properties for allocation.

3.2.19
source
entry of a product stream into a single allocation stage

Note 1 to entry: Quantities associated with source points can be measured or derived.

3.2.20
stream
⟨allocation modelling⟩ line depicting the flow of product from a source node to a delivery node

3.2.21
substitution
process in any system where nominations are used to target deliveries of products, whereby the difference between target production (nomination) and allocated deliveries are reduced through exchanges between allocation points

3.2.22
system balance
performance indicator used to track the difference between the sum of all sources and all delivery points for an allocation system or single allocation stage

3.2.23
validation
process of performing data and measurement checks

3.2.24
well allocation
split of produced or injected quantities back to each production or injection well

3.2.25
yield factor
expected returns of hydrocarbon liquids as a proportion of the potential liquids contained within a gas stream

3.3 Streams

3.3.1
injection gas
gas injected into the field's reservoir to maintain reservoir pressure

Note 1 to entry: The gas is not specific to anyone producing well, as is the case with lift gas, and the gas might not appear from production wells until, perhaps, years after injection has begun. The allocation of injection gas is usually different from the allocation of lift gas.

3.3.2
lift gas
riser gas
gas that is pumped down a well to assist in that well's production

Note 1 to entry: For the purposes of allocation, all the gas pumped down the well is assumed to be recovered with the well production fluids. However, the lift gas can mix with the reservoir gas and can change its composition. This can affect a volume-based allocation.

3.3.3
utility gas
gas that is vented, flared or burnt as part of normal operations

Note 1 to entry: Utility gas includes the following:

— Vent/flare gas: All producing fields shall have a means of maintaining a positive pressure in all vent lines from the processing facilities to atmosphere under normal operating conditions and to have the capability to vent large amounts of gas in case of an emergency. At present, the method to do this is to continuously vent gas to the atmosphere. Relatively small quantities of gas can be vented into the atmosphere un-ignited from some facilities. Usually, to make the gas safe, it is ignited on leaving the vent stack, when it is known as flare gas. This gas is waste product, but it is necessary to account for it a) in normal operation, when there are usually small quantities; and b) when large amounts are vented during an emergency. The allocation for these two scenarios is usually different.

— Fuel gas: Fuel gas used by the plant is usually provided from the gas extracted from the incoming fluids. The allocation of fuel gas is usually driven by commercial or contractual considerations, so measurement applications can be very varied. New European environmental laws require operators to calculate the amount of CO_2 vented to the atmosphere; hence this requires the amount of CO_2 to be measured and allocated. (A component-based allocation system seems to be suitable for this.)

— Start-up gas: Gas imported from other facilities to fill pipelines or equipment on facilities prior to start-up. Depending on the size and pressure of the system, these quantities of gas can be large [e.g. for a 300 km, 91,5 cm (36 in) pipeline operating at 13 MPa (130 bar)] and should be considered in the allocation process.

4 Allocation fundamentals

4.1 Allocation definition and objective

Allocation is the mathematical process used to determine the part of productions and products quantity belonging or to be attributed to each of contributors (fields/wells) and users of some installations when they are sharing such installations.

In such cases, productions/products to be attributed and allocated to each user cannot be measured directly. Consequently, allocation calculation using dedicated measurements and information shall be developed and implemented.

The objective is to conduct allocation according to acceptable and agreed methods to ensure the contributors and license owners obtain their fair share of the comingled stream from gas facilities and that no parties experience unnecessary or unknown losses.

4.2 Allocation and metering

Allocation implementation requires flow information i.e. flow or quantities as well as flow composition and fluid properties.

Allocation and metering including fluid analysis are complementary. They cannot be dissociated and shall be treated consistently for optimization purposes to define allocation and metering concept.

4.3 Gas productions facilities

Gas production facilities include all installations involved in production, transportation, processing and storage of gases, associated liquid and water as well as end products like dry gas, LPG, LNG, condensate. Allocation also applies to facilities dealing with nonhydrocarbon gas like H_2 or CO_2.

There can be a large variety of facilities or systems concerned with gas allocation; see Table 1.

Table 1 — Typical gas facilities

Gas facilities	Products
Gas/condensate wells	Raw gas and liquids
Subsea networks	Gas and liquids/methanol
Upstream production facility including pipeline, gathering and processing facilities	Gas, water and condensate
Transportation system	Gas and liquids
Gas terminal	Sales gas and liquids
Gas storages including CO_2	Gas, water and GCO_2
LNG plant	LNG, gas, liquids
CCS facilities	LCO_2, GCO_2,
H_2 facilities	LH_2, GH_2

The nature of gas facilities installations (onshore, offshore, subsea) dictates equipment selection for measurement and analysis and consequently affects allocation system definition.

4.4 Allocation applications and cases

Allocation shall be performed whenever at least one of following scenarios is found:

— no individual measurement of production and products from wells, fields, etc.;

— commingled processing/transportation;

— different usage of commodities by fields /system users;

— different operators;

— different percentage ownership/tax regimes for wells and fields.

When allocation is required, allocation systems shall be designed and implemented combining measurements, sampling, analysis and calculation to accurately determine the quantity of end products to be allocated to each field or owner.

The allocation of gases depends on facilities as well as streams and stakeholders involved in process. Some potential cases are listed below:

— allocation of gas and liquid to production wells and installations: subsea or topside;

— allocation of pipeline outlets to shippers;

— allocation of commercial products to producers;

— allocation of utility gas (fuel gas, gas lift) to users;

— flare and gas release (vent) allocation to contributors.

4.5 Allocation types and classification

4.5.1 General

Allocation can be:

— technical, i.e. addressing physical quantities/volumes;

— contractual, i.e. to reflect agreements in place and calculate the ownership of each stakeholder or partner in a given contract.

4.5.2 Technical allocation

Technical allocation applies to procedures used to calculate individual contributions of each well to a global production/injection. The technical allocation is mainly done daily and monthly but can also be hourly for assets dealing with gas sales agreements.

An example of technical allocation is production well allocation. This consists of calculating well productions based on well estimations models and reference quantities measured from production facilities outlets (fiscal measurements) and intermediate reference measurements.

The main purposes of technical allocation are:

— to report consolidated/validated figures on each well to partners (daily and monthly);

— to provide the same consolidated figures internally to the departments for operations, well performance, and reservoir management as input data for wells and reservoir models simulations.

4.5.3 Contractual and fiscal allocation

Contractual allocation can be different from technical allocation. A contractual allocation is governed by allocation agreements and commercial agreements. It determines the final ownership of installation users as well as their contribution and usage in utilities and/or disposals which can influence net allocated quantities.

In other words, contractual allocation considers how to calculate net quantities and final products to be allocated to users of shared facilities. It does so by considering the allocation of disposals and utilities like fuel gas, which can be user-specific.

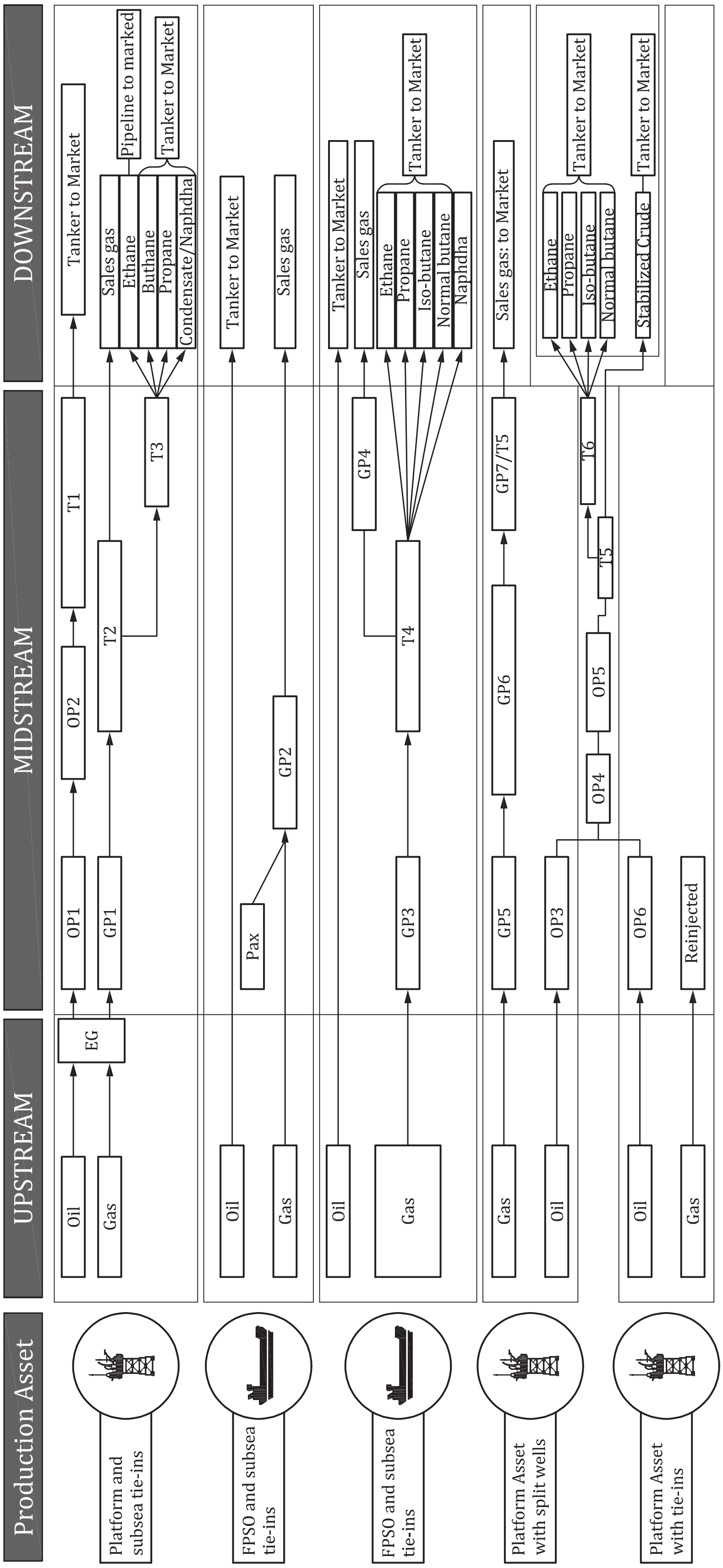
Allocation used to calculate ownership of different users of a system for revenue and taxation purposes can also be referred to as fiscal allocation.

For contractual and fiscal allocation, calculation principles and formulae as well as associated measurements for allocation shall conform to agreements in force between different entity.

4.6 Allocation in the value realization chain

Depending on the installation, allocation can be performed in several steps or areas.

For example, the hydrocarbon value chain can be divided into upstream, midstream and downstream areas with different operators. A hydrocarbon management or allocation system can be designed and used for upstream, midstream and/or downstream areas or for the hole hydrocarbon value realization chain. Each operator has their own allocation system; see Figure 2.



Key

EG export gas

Pa production asset

GPx gas pipeline x

SG sales gas

OPx oil pipeline x

Tx terminal/plant

Figure 2 — Hydrocarbon value chain

A hydrocarbon flow stream consists of several products. The value of the fluid is dependent on the composition of the products. If the hydrocarbon stream at the end of the value chain is sold by single products or energy, the components or the gross calorific value (GCV) shall be tracked through the value chain. The GCV and density can be calculated from the gas composition (see ISO 6976).

In a hydrocarbon value chain, there can be several commingle or split points related to processing or transportation with other producers. The properties/value of the fluid changes after each point. The change should be documented/calculated by adequate (quantity) measurements and (quality) sampling.

4.7 Allocation boundaries and steps

Allocation boundaries describe the physical set up, i.e. the installations or networks concerned, of a specific allocation with its specific input and output streams as per Table 2.

When designing allocation systems, a key issue is to identify and define the allocation boundaries with their different sub-perimeters as well as the steps to take to ensure consistent reconciliation and allocation calculations.

Table 2 — Allocation boundaries

Perimeter	Products examples	Typical input streams
Terminal/delivery point	Sales gas Fuel gas Stabilized crude oil Condensate Water	Field exports
Pipeline	Oil, gas, water	Installations deliveries/field exports
Central production facilities	Oil, gas, water exports, water dis-charged	
Offshore platform/subsea line	Oil and gas outlets Water disposals	Wells streams and flow lines

In a classical system with large boundaries, including all installations between terminal and wells as per Figure 3, allocation is performed using the five steps outlined in Table 3.

Table 3 — Example of allocation steps

Step number	Description
1	Plant streams, i.e. export/sales gas + condensate + utility gas from plant P to be allocated to A, B and C
2	A production as well as utility gas from A to be allocated to A1, B2 and B3
3	B production as well as utility gas from B to be allocated to B1 and C1
4	C2 allocated production estimated from C minus utility gas from C
5	Well back allocation from A1, B1, B2, C1 and C2 back to wells

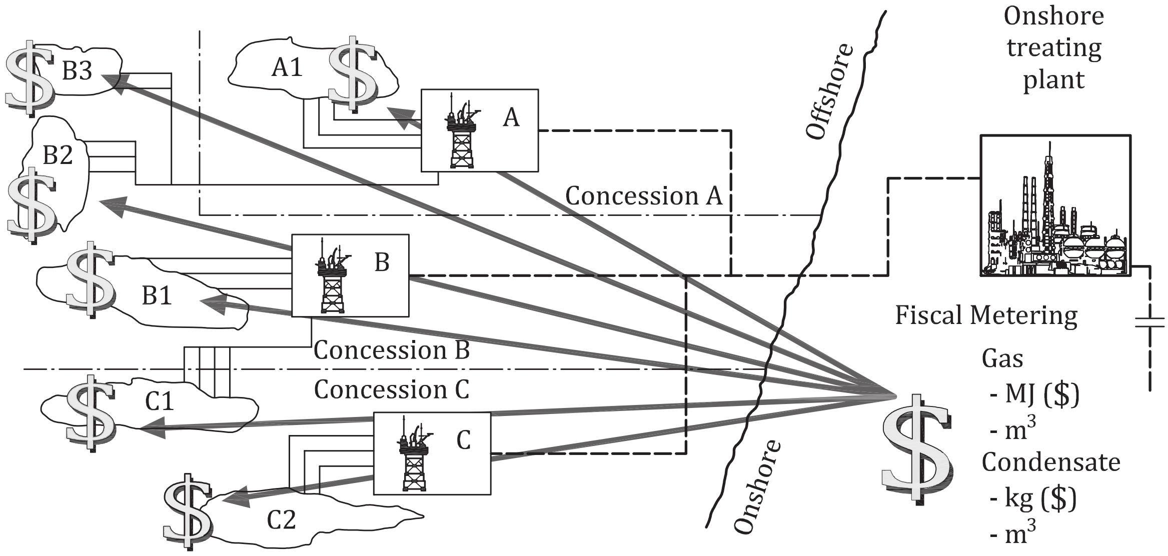


Figure 3 — Well to terminal system

4.8 Physical streams

4.8.1 General

Prior to allocation calculation, all streams taking part in allocation shall be identified and characterized in terms of property and fluid thermodynamical state.

Key streams include both output streams and products which shall be allocated and input streams corresponding to stream entering facilities via an entry point before being commingled and processed to give products.

4.8.2 Products

Products are the quantities which shall be allocated between contributors and users. From an allocation viewpoint, products are usually either at the point of sale or disposal, or feed into another allocation system.

However, these product streams are not restricted to streams providing sales value for users. With the increasing emphasis on monitoring and reporting of emissions and discharges (including taxes, tariffs, penalties and trading schemes) streams for disposal, such as produced water, fuel gas and flare, can have a direct financial impact and shall be included. These are normally treated as products streams.

See Table 4. Products streams can include:

— any marketable products derived from processing wet gas or gas like sales gas, LPG and LNG;

— nonhydrocarbon gases like CO_2;

— associated liquids produced by gas and gas condensate fields.

Table 4 — Product streams

Product stream	Offshore platform	Onshore gas plant	Gas pipeline
LPGs		✓	
Natural gas liquids	✓	✓	
Wet gas or export gas	✓	✓	✓
Sales quality gas	✓	✓	✓
LNG		✓	
Fuel gas	✓	✓	✓
Flare gas	✓	✓	✓
Import gas	✓		✓
Re-injection gas	✓		
Produced water	✓	✓	
Re-injection water	✓		
H_2 import		✓	✓
CO_2 import/ export		✓	✓

4.8.3 Input streams

Depending on the case, input streams can be:

— well productions;

— well hookup, platforms, flow lines, risers' exports;

— fields exports;

— pipeline inputs;

— terminal inputs;

— any other gas or liquid inputs into systems.

4.8.4 Fluid characteristics

Whatever fluids are multiphase, wet gas or single phase, quantities measured or determined at actual conditions shall be converted at standard conditions. Fluid behaviour versus pressure and temperature and specifically fluid change from measurement conditions to reference conditions shall be recorded.

More details on fluid types and behaviour are given in Clause 5.

4.8.5 Gas and liquid compositions

There are a variety of fluid compositions depending on the type of stream. Stream compositions can consist of several hydrocarbon components such as methane, ethane, propane, butane, pentane, hexane, heptane and heavier components as well as non-hydrocarbons components such as CO_2, H_2, N_2, H_2O, H_2S, etc.

In allocation calculation, components are referred and indexed with C_1, C_2, C_3, iC_4, nC_4, iC_5, nC_5, C_6 and so on up to C_n. Combinations of components with higher hydrocarbons numbers than C_6 are referred to as C_{6+} or C_{n+}.

4.9 Allocation process

For a given allocation perimeter, a standard allocation process generally involves the following tasks which concern both measurements as well as specific allocations items:

— well measurements (well test, wellhead measurements);

— stream flow measurements, including, when possible, condition-based monitoring;

— stream sampling and analysis, calculations at the measurement points for the incoming and outgoing streams;

— possible corrections on flow measurements: correction factors;

— balancing and reconciliation between the incoming and outgoing amounts (losses);

— utilities allocation, like fuel consumption and gas lift;

— disposal allocation;

— inventory calculation and allocation if needed;

— calculation of user's/owner's share in the comingled outgoing stream based on the allocation method;

— official reporting.

4.10 Gas allocation cases summary

The typical gas products to allocate per system are summarized in Table 5.

Table 5 — Gas allocation matrix

	Gas	HC liquid	Water	Dry gas	Sales gas	LPG	LNG	Condensate	H_2	H_2S	CO_2	Fuel and flare
Wellhead platform	X	X	X									X
Processing facilities	X	X	X	X				X				X
Pipeline				X	X			X	X		X	X
Terminal					X	X		X			X	X
LNG plant						X	X	X			X	X

4.11 Allocation methodology

Methods of allocation are generally classified in four groups as per Reference [29]:

a) allocation by pro-rata;

b) allocation by difference;

c) allocation by process simulation with flash calculations;

d) uncertainty-based allocation.

Detailed descriptions are given in Clause 7.

The methods can be performed in energy, mass or volume. Allocation based on energy or mass by hydrocarbon components are the most comprehensive. If allocation by volume is used for well back allocation for reservoir monitoring purposes, it is generally not recommended for fiscal allocation but can be accepted when allocation by mass is not possible or the products or energy has minimal affiliation. An example is utility gas allocation, where mass measurement nor representative sampling of the flare is possible. If the flare gas is a small share of the utility gas consumption, it can be assumed that the flare gas composition is equal to the fuel gas composition or an agreed density can be used to convert volume to mass.

4.12 Balance and reconciliation

4.12.1 Balance

In an ideal system, receiving and exporting flows with no losses, on a given period, shall balance as per Formula (1).

$$I + I_S = O + C_S \tag{1}$$

where

I is inputs;

I_S is initial stocks;

O is outputs;

C_S is closing stocks.

The imbalance I_B calculated as per Formula (2):

$$I_B = \sum x_{OUT} + s_{t2} - (\sum x_{IN} + s_{t1}) \tag{2}$$

where

s_{t2} is the stock at time, t2;

s_{t1} is the stock at time, t1 with t2 > t1.

shall equal to 0.

Imbalance other than 0 indicate either loss/gain or measurement issues. Ideally, material conservation shall be achieved with $I_B = 0$.

Imbalance is an indicator used to track the difference between the sum of all inputs and outputs of a production system corrected by stocks/inventory changes prior to allocation.

A significant imbalance I_B can indicate measurement errors/discrepancies or losses.

In all cases, imbalances calculations should be carried out over a representative period to check ins equal to outs. Inventory change shall be considered in imbalances determination.

Material imbalances calculation is carried out on a volume, mass, molar or energy basis, depending on the allocation type and the measurement system as well as analysis availability.

The advantages and disadvantages of the most common methods are summarized in Table 6. (From Reference [12].)

Although volume balancing has several disadvantages (principally, the complexity of conserving a material balance), it is widely used as many stream measurements are made using volumetric meters. Also, for historical reasons, reports are frequently requested in volume units (e.g. barrel of oil or standard cubic foot of gas).

Table 6 — Advantages and disadvantages of allocation balance basis

	Mass balance and component mass balance	Component molar balance	Volume balance	Energy balance
Advantages	— A mass-balanced system is easy to understand. — Mass is not affected by phase change.	— A molar balanced system is easy to understand. — Molar quantities are not affected by phase change. — Gas analyses are typically in mole per cent. — Molar compositions are required if flash calculations are to be performed.	— Volume is simple and easy to understand. — Volume measurement is a common method for metering oil and gas. — Industry uses volume for routine reporting of production reporting and reserves	— Allows swapping of components between product streams. This can enhance the flexibility of the allocation system, e.g. if one user prefers gas and another prefers NGL.
Disadvantages	— Direct mass measurement is not widely used. It is therefore generally necessary to convert from volume measurement, which requires composition, pressure and temperature data	— Molecular weights of non-standard components can be unknown. — Molar measurement (stream compositional analysis) is often not known.	— Volumes are not additive so they are not normally conserved across a process. This is because volumes: a) change with pressure and temperature; b) change with phase changes. — Accurate pressure and temperature data are required at all measurement points to allow calculation of standard volumes. — Differing standards can cause confusion. e.g. stock tank conditions and standard conditions are not the same.	— Calculations require composition data for all streams. — Details of individual components are lost. — The value of components is not correctly recognized e.g. propane in a liquid stream has a different financial value than propane in a gas stream.

4.12.2 Reconciliation

Whichever allocation method or combination of allocation methods is selected, an overall material balance across the system shall be established. Due to uncertainties in measurements and estimates, it is unlikely that the sum of input quantity equals the sum of products.

Reconciliation is a mathematical process to ensure consistent input and output flows satisfy the material balances.

Standard reconciliation practice is to normalize inputs data to match output quantities. This is because outputs are generally measured accurately and are considered official.

Reconciliation is achieved mathematically by performing a simple pro rata method assuming the output stream is the correct value. See Figure 4, which represents oil reconciliation for field allocation.

Outputs are considered correct. Imbalance is distributed based on contributions.

Some systems can use redundant data. For example, an onshore gas plant can measure flow and composition of all the feed streams and of all the product streams. However, due to measurement uncertainties, the total feed is unlikely to equal the total products. In this event, the more uncertain measurements are reconciled to the less uncertain measurements. Normally, the feed streams are reconciled to match the product streams.

For modern flow meters, condition-based monitoring techniques, i.e. online diagnostic tools, can reduce the likelihood of any flow measurement bias going unnoticed.

Reconciliation is then performed using flow data uncertainty and optimization algorithms thanks to data validation reconciliation approaches in which input and output flow data are adjusted to satisfy mass balance equation.

This type of method, which can be used to detect errors, can be used internally to ensure the data sets are consistent and the balances are closed prior to allocation.

Redundant data can be useful as they can reduce the uncertainty in the data that are used.

4.13 Units

In this document, SI units are used as well as the following:

— pressure is expressed in bar absolute or bar units[1)];

— volume is expressed in Sm^3 at standard conditions (at 15 °C and 1 atmospheric pressure).

Allocation may be conducted in mass (kg), since mass is not influenced by pressure and temperature to the same extent as volume. Mass calculation has less uncertainty.

It can be necessary to express gas volumes in oil equivalent (O_E). In the absence of any other specific formula, the following conversion can be used:

$$1\ m^3\ O_E = 1\ 000\ Sm^3 \text{ gas @ } 40\ MJ/\ Sm^3$$

4.14 Upstream allocation example

An example of an upstream allocation is shown in Figure 4. The asset has four tie-in fields/streams to a common process facility. Allocation can be conducted using pro-rata calculations, by difference calculation or simulation. The calculation can be in units for mass, energy or volume. The measurement can be executed on single or multi-phase fluid at different rates.

NOTE Representative flow proportional sampling is only obtainable for single phase fluids.

1) 1 bar = 0,1 MPa = 10^5 Pa; 1 MPa = 1 N/mm^2.

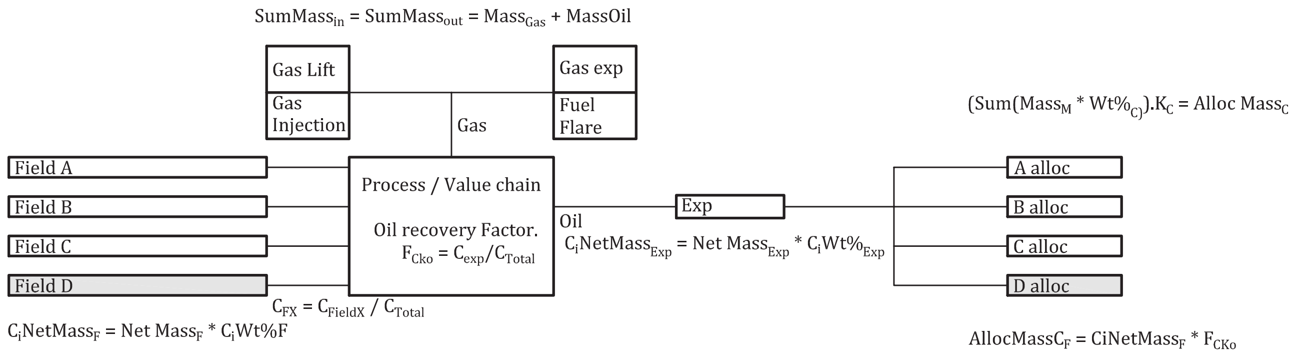


Figure 4 — Upstream allocation example

4.15 Contractual gas allocation

4.15.1 General

Prior to entering gas allocation system negotiations, the underlying framework of commercial agreements (either existing or being negotiated) and the technical characteristics of the production system, pipeline and terminal shall be known. For example, each system user's perception of the local gas market influences the importance that party places on different aspects of the allocation agreement, such as the following:

a) security of gas supply with the aim to sell gas on a long-term contract:

   1) allocation and attribution period set to one day;

   2) limited re-nomination with relatively long lead times;

   3) priority system for the attribution process;

   4) mechanisms for notified and system substitution;

   5) pipeline stock controlled by the pipeline system operator.

b) flexibility of gas supply in a de-regulated system with the aim to sell gas on the spot market:

   1) allocation period set to less than one day;

   2) relatively short re-nomination lead times;

   3) no priority system with the allocation process;

   4) no gas substitution;

   5) all nominations and re-nominations treated as firm;

   6) line pack controlled by the system users;

   7) within a day production changes to supplement gas delivery.

The specific situations are never as clear-cut as outlined above. There are other issues that impact the gas buyers and/or the system users, e.g. independence and capacity rights. However, unless a high-level analysis is undertaken, and the main issues evaluated prior to entering negotiations, it is likely that the allocation system does not fulfil the system users' requirements and objectives. In extreme cases, the poor quality of the allocation system can impinge on the operation of the offshore production facility and/or limit the opportunity to sell gas in the open market.

Allocation agreements are commercial agreements with technical input and not the other way around. Attempting to develop a gas-allocation system in isolation has the potential to produce an allocation system that does not fit either commercial or technical purposes. The following issues shall be considered:

— Is the gas being sold to individual or multiple buyers?

— Is there one or are there multiple gas sales points?

— Is the gas being sold on a short-term or long-term contract basis?

— Is there a spot market available for gas sales?

— Are there penalties for under-delivery or off-spec delivery?

— Are there any restrictions in the use of system capacity by a system user?

— How is the gas from the production system being used within a system user's gas sales portfolio?

— How flexible is the production system to respond to required changes in flow rate?

— Are there any local statutory regulations/considerations with respect to measurement devices, reporting and/or gas balancing?

4.15.2 Gas-allocation issues

From a technical standpoint, developing a gas-allocation system shall include all aspects of the overall process design and operation. This includes the implications of variations in processing conditions and gas compositions on the terminal product. From a commercial standpoint, gas allocation system development shall be consistent with the gas sales agreements and the overall commercial structure.

By its very nature, a gas-allocation system encompasses a wide range of topics. These include:

— measurement methods;

— flow meter validation and diagnostic suites;

— standards;

— laboratory techniques;

— data auditing;

— allocation principles and procedures;

— nomination, substitution and attribution procedures;

— statutory requirements;

— IT system development;

— audits, tax and related commercial transportation;

— operating and processing system agreements.

The various issues are further explained in the remainder of this document.

4.15.3 Measurement

Measurement includes metering and sampling. Measuring is required to establish the quantity and associated quality of the gas exported from the production system into the pipeline and the product leaving the terminal. An understanding of the different types of metering systems, sampling equipment and associated analytical techniques is required. This information is required to ensure that the meter specified is correct for the service and accuracy and that the sampling installation is installed in the appropriate location. Flow meters can have condition-based monitoring, i.e. online diagnostic tools, that indicate if the meter is operating correctly or if it malfunctions.

The specification of metering and sampling equipment at each measurement point should be designed in accordance with applicable standards and local regulations. Commercial considerations can have an impact on this specification. For example, it can be agreed that a marginal field can use a standard of metering with a higher uncertainty if the overall financial risk is mitigated. Measurement points include:

— pipeline entry measurement point(s) for gas and liquid;

— terminal entry measurement point;

— terminal measurement exits point(s) for gas and liquid;

— terminal fuel gas;

— terminal flare gas;

— liquid storage.

In addition, the sampling systems are utilized to monitor the entry and exit streams to ensure that the composition specifications are achieved.

4.15.4 Terminal products

Terminal products relates to the onshore processing of the commingled gas stream to ensure that the sales gas and associated liquid product(s) meet the required specifications. In general, more liquid products requires a more complex allocation procedure. An understanding of the terminal process design is required to ensure that the developed procedures correctly reflect each field's entitlement.

4.15.5 Pipeline capacity

Pipeline capacity relates to the steady-state and transient operation of the gas pipeline. The allocation procedures shall not inhibit pipeline operation and vice versa.

4.15.6 System response time

System response time relates to the speed at which the offshore process, the pipeline and the onshore terminal can individually respond to a required change in system throughput. An understanding is required because of the need to ensure that the process reflects the dynamics of the system.

4.15.7 Agreements

4.15.7.1 Gas sales agreement

The gas sales agreement specifies the gas specification at the re-delivery point, nomination procedures, forecasting and gas measurement required. It therefore directly impacts the allocation process. An understanding is required to ensure that the allocation agreement enables the principles of the gas sales agreement to be applied or that the gas sales agreement can be negotiated to fit with the system's allocation agreement.

4.15.7.2 Commercial agreements

Commercial agreements relate to the transportation and processing agreements that specify, among other things, capacity rights, specifications and system-wide capacity constraint procedures.

4.15.8 Regulatory

4.15.8.1 Statutory obligations

The statutory obligations relate to specific reporting requirements, which can be technical (e.g. measurement), that are incorporated into the agreements.

4.15.8.2 Tax implications

Processes should be developed for the tax implications that recognize those fields that are liable for specific taxes and those that are not liable. Consideration should be given to the most tax-efficient option when developing the allocation procedures.

4.15.9 Commercial issues

4.15.9.1 Attribution

Attribution is the procedure for sharing out the terminal's gas production between the participating fields, primarily based on nomination data. Attribution relates to the commercial movement of gas through the system and can be independent of the measured input quantities.

A series of mathematical equations shall be specifically developed to establish each system user’s share of the gas exported from the terminal. The procedures are based on the user's gas allocation, nomination and specific substitution rights.

4.15.9.2 Nomination

Nomination relates to the quantity of gas requested by a buyer from a system user for delivery from the terminal. The aggregate nominations of all system users (from a field) are used to establish the field’s contribution of production into the pipeline system.

4.15.9.3 Substitution

Substitution is the mechanism that enables one user to lend or borrow gas (exported from the terminal) to/from another system user to meet either system user's nominations.

The difference between a field's allocated and attributed quantities is substitution. Substitution is a mutual self-help process that is controlled at the terminal by the terminal operator. The terminal operator is aware if a producing area is having difficulties meeting the production targets and can find another operating area that can contribute; and vice versa if a producing area can produce excess gas. Limitations can be imposed on the level of lending, borrowing and the payback period.

4.15.10 Time period

The time period relates to the allocation and attribution calculations. Consideration is given to daily, hourly or another allocation period. It is possible that the allocation period is not linked to the nomination period, e.g. when there is an hourly allocation period but a daily nomination period. In addition, there often exists downstream gas transporters “balancing” periods. This balancing period is the time frame within which the downstream gas transporter can levy penalties for imbalances between inflow and outflow, e.g. an hourly allocation period but a balancing period of 4 to 6 h. This gives the gas time to travel from the input point to the output point. The allocation period is shorter as this enables the shippers to manage their imbalance positions within the balancing period.

4.15.11 Forecasting

Forecasting ensures that the lead times for the provision of the data required by the gas sales agreements and the production and planning targets for the terminal and platform operators are incorporated.

4.15.12 Pipeline stock

Pipeline stock relates to the use of pipeline stock to help achieve gas delivery. It is necessary to consider which commercial party controls the level of stock in the pipeline, e.g. the pipeline/terminal operator or the system users.

4.15.13 Existing systems

The system shall seamlessly integrate with existing gas-allocation systems and with the existing procedure associated with existing downstream systems.

4.15.14 Data timing

Data timing ensures that nominations and any potential re-nominations within the allocation agreement coincide with the requirement of the gas sale agreements and operational requirements.

4.15.15 Data flow and reporting

Evaluating data flow and reporting ensures that sufficient information is provided to check the allocation and attribution reports prepared by the system operator. Where individual parties receive data, all parties shall receive the same information at the same time. Business processes are required for the terminal operator to advise the field operators to increase/decrease the flow of production into the pipeline system.

4.15.16 Auditing

Auditing provides a means of checking the overall operation of the system operator if errors are found within the allocation statement. This issue shall be a priority item within any allocation-agreement negotiations.

4.15.17 Fallback

A detailed fallback plan establishes how nominations and data flow are provided if the normal communication processes fail or meter data do not exist.

4.15.18 Summary

The results from allocation calculations establish each participant's revenue from the system. A gas-allocation agreement is not a technical agreement. During the negotiation of an allocation, system users should be wary of statements that imply that the allocation agreement is purely a technical arrangement and, hence, should be developed by the technical departments.

In conclusion, when gas from two or more entry sources are commingled and processed in a common pipeline and terminal system and the sources have different ownership and/or operate under different tax regimes, a gas-allocation system is required. The allocation system shall provide a fair, equitable and auditable means of sharing out the products from the system to the entry sources and to the associated partners recognizing the specific delivery requirements of each participant.

The following should be considered:

a) All allocation procedures are unique and are specifically designed for a given system driven by commercial considerations.

b) For an allocation system, technical solutions are developed to meet the specific commercial requirements.

c) There is no standard allocation procedures but there are standard elements and approaches that combine to produce the overall allocation system.

d) As with any other commercial agreement, allocation agreements are finalized because of negotiation and compromise. It is therefore not good practice to take an existing agreement and attempt to modify it without discussing the terms of the agreement with the parties that negotiated it.

e) It is necessary that an allocation/attribution system is not developed in isolation from other commercial agreements, e.g. transportation and operating agreements.

5 Fluid property and parameters for allocation

5.1 Fluid types

In gas facilities, the fluid can be multiphase, wet gas or single phase.

Fluid behaviour (specifically how the fluid changes from measurement conditions to reference conditions) against changes in pressure and temperature shall be used to calculate allocation parameters and convert the quantities measured or determined at actual conditions in standard conditions.

Unsaturated (or stabilized) and saturated (non-stabilized) fluids and gases shall be distinguished.

Table 7 illustrates types of fluids per locations and products.

Table 7 — Typical fluid types per streams and products

	Multiphase	Single phase	Unstabilized	Stabilized
Input streams				
Well productions	x	x	x	
Field productions	x	x	x	x
Pipeline inputs	x	x	x	x
Terminal inputs	x	x	x	x
H_2 import		x		x
Import gas/water		x		x
Diluent		x		x
Gas lift		x		x
CO_2 import		x	x	x
Products				
Oil export		x	x	x
Sales oil and condensate		x		
LPGs		x	x	
Export gas including C_2, C_3		x		x
Sales gas		x		x
LNG		x	x	
Fuel gas		x		x
Flare gas		x		x
Gas injection		x		x
Produced water		x		x
Water disposal	x	x		x
Water injection		x		x
CO_2 export		x	x	x
H_2 export		x		x

5.2 Gas and liquid properties

5.2.1 General

Thermodynamic properties (e.g. composition, density, phase fractions) and fluid characteristics (e.g. viscosity) shall be used to determine flow rates from primary measurements (e.g. velocity, pressure drop, attenuation, frequency, absorption).

In 7.1, the calculation method is addressed for use when fluid properties and/or composition:

— change with pressure and temperature;

— are not measured or cannot be measured directly.

At the conditions prevailing at the measurement point, streams can be stabilized (gas phase or liquid phase) or non-stabilized either as one phase (gas or liquid) or as two phases (gas and liquid).

5.2.2 Stabilized fluids

For stabilized gases, calculation routines to derive density and compressibility factors are based on existing standards such as ISO 6976 using composition, pressure and temperature to derive density and compressibility factors.

For density and compressibility factors of liquid, API or ISO standards API MPMS Chapter 11 or ISO 91 may be used if applicable.

5.2.3 Equilibrium gas (separated gas at dew point)

Equilibrium gas is defined as separated gas that has no free liquids but can develop a small liquid content by changes in process conditions or meter/pipe-work interaction. Any process changes of the gas can cause a shift in the definition of the gas as wet or dry.

The measurement devices that can be used for equilibrium gas are like the devices mentioned for dry gas application. However, in the design, care should be taken that as soon as liquids start to form (e.g. due to pressure drop in the meter), the effect on the reading should be established.

5.2.4 Equilibrium liquid (separated liquid at bubble point)

Equilibrium liquid, i.e. liquid from a separator at its bubble point, in principle contains only liquid. However, small amounts of gas can break out in situations where a pressure drop is encountered (e.g. valves or metering equipment). This condition occurs when the head pressure has been sufficiently reduced or the temperature increased to cause gassing-off or boiling of the fluid. This gas breakout usually gives rise to measurement errors if single-phase liquid meters are used. Measurements of these fluids require care and attention in view of the pipe geometry and line sizes to ensure that the liquid is below its bubble point at the measurement point. Meter shall be selected and pressure drop should be minimized to prevent meter performance degradation.

5.2.5 Flash calculations for non-stabilized and wet gas flows

For non-stabilized fluids including two-phase flows, such as wet gas, gas and liquid composition and properties shall be determined indirectly by flash calculations.

Flash calculations can be performed on-line or off-line using specific pressure, volume, temperature (PVT) software or a process simulator. If flash calculations are performed off-line and are complex, flash interpolation tables or equations can be generated and downloaded in flow computers or in any digital control system.

As an example, such tables can be two-dimensional tables containing values of density, liquid fractions for a specific well or field composition at specific values of temperature and pressure. For each composition, a flash table or equation can be generated.

The flash-calculation specification requires fluid composition based on components and pseudo-components previously defined with their respective properties (e.g. molecular weight, specific gravity, and boiling point) based on laboratory analysis and properties tuning.

These calculations also require selection of an appropriate equation of state and the appropriate flashing conditions.

5.3 Fluid information for allocation

5.3.1 Fluid compositions

For allocation based on mass or molar balance, mass is conserved across the system. It is therefore possible to allocate each component individually, having identified the components from analysis data.

The compositional breakdown, or component slate, shall be specified in the allocation system. This is required to be in sufficient detail to allow tracking components in the allocated products.

Similarly, each time allocation calculations like simulation require composition inputs, a relevant stream composition shall be identified and selected.

For gas streams, individual hydrocarbons from methane (C_1) up to a carbon number should be allocated which is deemed sufficient to characterize the streams. Typically, this is at least up to pentanes (C5s). It is recommended that the isomers associated with each alkane up to at least pentane (C_5), and which are present in significant quantities, are measured and treated as individual components in the allocation system rather than being grouped by carbon number.

However, for larger carbon numbers it may be necessary to group the isomers and form hypothetical components. For example, hexanes (C_6s) and heptane's (C_7s) may also be individually allocated but, more frequently, trace amounts of any heavier hydrocarbons present are grouped as one component, to give C_6+, C_7+ or C_8+ as the heaviest component. The heaviest component should be selected with care, as the heaviest component (e.g. octane plus) has a great effect on the dewpoint of a gaseous mixture of hydrocarbons. H_2S and inert gases such as nitrogen (N_2) and carbon dioxide (CO_2) should also be allocated if quantities are significant.

For associated liquid streams, the selection of components is more problematic. For the heavier hydrocarbons, there are numerous isomers and derivative compounds (e.g. benzene, cyclo-hexane etc.). It is not always practical to analyse oil streams for all compounds, or to allocate all components.

The heavier components in liquid systems are represented by carbon number or boiling point fractions obtained from distillation. These are expressed as mass or molar fractions.

These fractions represent mixtures of similar hydrocarbons within ranges characterized by molecular weight, boiling point and density. If any form of value adjustment is to be performed, the boiling point fractions should be selected to relate to the petroleum products (cuts) upon which the cut value is based.

When using a process simulation model as part of the allocation, these carbon numbers or boiling point fractions can be defined as hypothetical components or pseudo-components. Most commercial models have the capability to predict other properties based on the main properties: molecular weight, boiling point and density (see 5.4 for a discussion on the use of process simulation models in allocation.)

When calculating allocation and simulation on hydrocarbon streams that give both gas and liquids, a component list able to represent both gas and liquid compositions i.e. ranging from C_1 to heaviest components shall be identified. As a minimum, the components C_1, C_2, C_3, n-C_4, iso-C_4, iso-C_5, n-C_5, C_6, C_7, C_8, C_9, N_2 and CO_2 should be used (lumping the C_{10+} higher hydrocarbons together). However, sometimes, the uncertainty requirements are such that all components listed in ISO 6976 should be used.

5.3.2 Fluid properties

The gas and liquid properties used in calculations shall be based on the best estimates of the composition of the gaseous and liquid fractions at the measurement point at the operating temperature and pressure.

5.3.3 Allocation process factors for gas allocation

5.3.3.1 General

When based on process parameters like pressure and temperature, simulation is used to determine allocation process factors, like volume conversion and gas recovery, which are used to derive flows at standard or end-of-process conditions resulting from inlet flows processing.

These factors are used to calculate the field's shares in comingled streams or conversion from flowing conditions to standard condition. The assumption in this method is that the component composition of the fluid is known over time and the equation of stated is representative for the fluid.

The simulation method is based on a simulation/flash program and (pre-)defined pressure(s) and temperature(s). The gas recovery factor or shrinkage factor is used to describe the difference between the incoming and outgoing stream mass, or volume conversion from flowing conditions to standard conditions at 15 °C and 1 atm pressure. The assumption in this method is that the component combination (quality) of the product(s) is stable and consistent over time, due to rarely or no online sampling.

Simulation method used in virtual flow programs are often used to the extent that there is no measurement nor component composition available for the PVT model. All calculation is based on measured live pressure and temperature. This method holds higher uncertainty than a method using a valid composition.

5.3.3.2 Volume conversion factors

Volume conversion factors are mainly used for well and reservoir volume allocation.

The well volumetric flow rates are calculated at the meter conditions. These calculated flows shall be converted to end of process at standard conditions. Conversion of actual flow rates to reference conditions requires the knowledge of the fluid composition as well as the mass transfer between the liquid and the gas phases. The conversion is therefore done using volumetric factors that readily relate the volume of fluids that are obtained at stock tank conditions to the volume that the fluid actually occupies at the metering point temperature and pressure.

These volume factors are calculated for a given composition and for a wide range of line pressures and temperatures and used for volume allocation.

If single-phase properties and conversion factors can be calculated by correlations, they are typically generated by thermodynamical simulation of the process at pressures and temperatures covering the operating range of the meters.

The following list gives typical conversion factors to consider when converting actual rates to standard rates:

a) gas conversion factor, B_g, expressed in m^3/Sm^3;

$$B_g = V_{\text{gas,meter}} / V_{\text{gas,standard}}$$

where

$V_{\text{gas,meter}}$ is the volume of gas at meter conditions;

$V_{\text{gas,standard}}$ is the volume of gas at standard conditions.

b) oil conversion factor, B_o, expressed in m^3/Sm^3;

$$B_o = V_{\text{oil,meter}} / V_{\text{oil,standard}}$$

where

$V_{oil,meter}$ is the volume of oil at meter conditions;

$V_{oil,standard}$ is the volume of oil at standard conditions.

c) water conversion factor, B_w, expressed in m^3/Sm^3;

$B_w = V_{water,meter} / V_{water,standard}$

where

$V_{water,meter}$ is the volume of water at meter conditions;

$V_{water,standard}$ is the volume of water at standard conditions.

d) gas-condensate ratio, R_v, expressed in Sm^3/Sm^3;

$R_v = V_{gas,standard} / V_{condensate,standard}$

where $V_{condensate,standard}$ is the volume of condensate at standard conditions.

e) solution gas-oil ratio, R_s, expressed in Sm^3/Sm^3;

$R_s = V_{oil\ solution\ gas\ evolved,standard} / V_{oil,standard}$

where $V_{oil\ solution\ gas\ evolved,standard}$ is the volume of oil solution gas evolved at standard conditions.

f) solution gas-water ratio, R_w, expressed in Sm^3/Sm^3;

$R_w = V_{water\ solution\ gas\ evolved,standard} / V_{water,standard}$

where $V_{water\ solution\ gas\ evolved,standard}$ is the volume of water solution gas evolved at standard conditions.

The so-called shrinkage factor used for liquid contraction is equal to 1/Bo.

Previous factors apply to multiphase meters, wet gas meters as well as gas and condensate streams which are not stabilized.

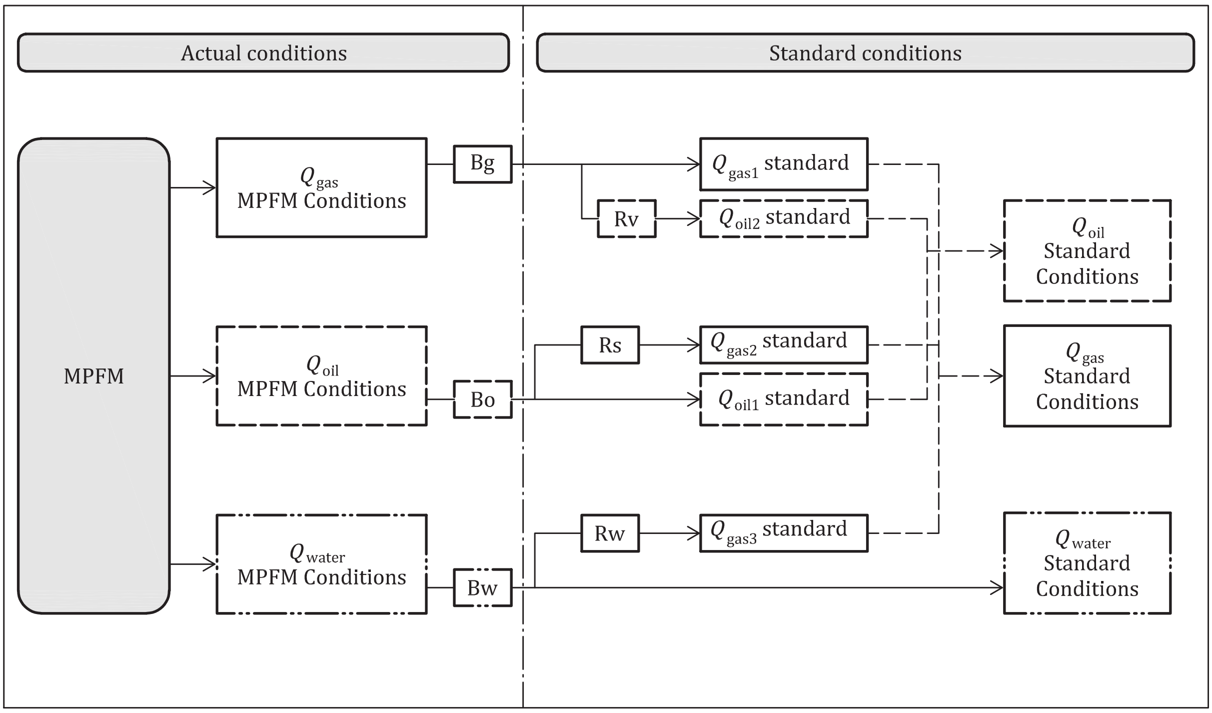


Figure 5 — Volume conversion factors for well volume allocation

5.3.3.3 Recovery factors

The oil recovery factor is used to describe the mass of oil in kg obtained after processing 1 kg of hydrocarbon at inlet.

The gas recovery factor is used similarly to describe the mass of gas obtained after processing 1 kg of hydrocarbon at inlet.

Similar factors can be derived for any liquid products obtained after processing like condensate, LPG, naphta, etc.

The condensate gas recovery factor is used similarly to describe the mass of gas obtained after processing 1 kg of condensate gas at inlet.

5.3.3.4 Yield factors

The gas yield factor is used to describe the mass of sales gas in kg obtained after processing 1 kg mass of hydrocarbon at inlet.

5.3.3.5 Condensate-gas ratio

5.3.3.5.1 General

In some situations, it is important to know the condensate-gas ratio (CGR). The methods given in 5.3.3.5.2 to 5.3.3.5.4 may be used.

5.3.3.5.2 Test separator

A field or well may be routed to a dedicated separator (test or production) that measures the gas downstream of the separator vessel, separates the hydrocarbon liquids from any water and then meters the associated hydrocarbon liquids. The following guidelines should be followed:

— The test should be performed for the maximum time possible to achieve the best possible accuracy, preferably in excess of 24 h. The well flow-line length should also be considered.

— The frequency of the tests should be specified within the agreement and should be based on the expected variation of hydrocarbon liquid production rates from the field(s).

— The well or field should be flowing prior to the beginning of the test to ensure steady state conditions and, therefore, a more accurate result.

— The meters should be of a good standard and the separator vessel of suitable capacity.

5.3.3.5.3 Tracer

Tracer methods can be used to determine CGR in a wet-gas stream. In principle, a suitable gas tracer and a suitable condensate tracer are all that is required. In practice, no suitable gas tracer has been found. This means that it is necessary to measure the gas flow on the stream in question. This discussion assumes there is a wet-gas meter of the differential-pressure type.

The following steps give the CGR:

a) Measure the flow rate of the condensate using a condensate tracer.

b) Measure the flow rate of the water using a water tracer.

c) Determine the total liquid flow rate.

d) Note the uncorrected wet-gas flow rate.

e) Determine the over-reading of the wet gas meter due to the liquid.

f) Correct the wet-gas flow rate to a dry-gas flow rate.

g) Determine the condensate-to-gas ratio.

5.3.3.5.4 Well test

For a well or field where there is no access to a permanently installed separator, the CGR can be obtained from a well test performed when the well is initially drilled or the subject of a work over. The gas is flowed to flare through a standard process of separation and metering the gas and liquids.

Essentially, this approach uses a test separation to acquire the required data; see 5.3.3.5.2 for further details.

5.3.4 Blending effect

This effect is considered on a case-by-case basis. More information can be found in HM 96 and Reference [38].

Blending hydrogen with natural gas is not addressed in this document.

5.4 Use of phase behaviour/process simulation models

5.4.1 Introduction

The use of process simulation models to directly allocate hydrocarbons between fields is discussed in 5.4.3. This subclause discusses such models and their uses in allocation more generally. Reference is made to a field in the discussion in this subclause, but it equally applies to a well, source or any identified entity that is being allocated. This method is used in combination with other methods.

Process simulation models provide information on hydrocarbons when they undergo pressure and temperature changes within a process plant. Simple applications include prediction of physical properties and calculation of shrinkage factors. More complex models can predict the flow of feed streams through an entire process and identify the destination of specific feed components supplied by each field (as described in 5.4.3).

5.4.2 Applications

Typical applications and uses of process modelling in allocation include:

— calculation of oil shrinkage or gas expansion factors;

— calculation of component recovery factors;

— direct allocation of hydrocarbons (as described in 5.4.3);

— estimation of unmeasured streams (e.g. well streams), thereby providing a pseudo-measurement;

— providing access to extensive databases of physical property information within simulation packages which can be extracted for use in allocation calculations (e.g. liquid densities, gas calorific values) for both individual compounds and multi-component mixtures at varying conditions.

However, the use of simulations can introduce complexities, for example:

— the requirement for operator intervention to achieve a stable solution, operator expertise is therefore essential;

— they can make the allocation process more difficult to understand;

— they are limited by the accuracy of the input data and the fundamentals of the model itself.

These factors should not preclude the use of simulations as their inclusion should be dictated by the requirements of the allocation system. These factors are highlighted so that the correct expertise is employed in their specification and operation.

5.4.3 Process simulation model types

Process simulation models are normally associated with commercial simulation packages. However, there are several approaches available to model the process:

— commercial process simulation software;

— use of correlations;

— use of lookup tables;

— use of K factors, simple flash calculations or other simple mathematical models.

Most commercial simulation packages are designed for process engineering applications to assist with system and equipment design. These models can be complex and present difficulties for routine operation by non-process engineers and integration with allocation system software packages. However, there are process simulation packages that are designed primarily for allocation purposes, which overcome these system integration and operational issues.

Historically, because of the perceived difficulties with the routine running of the process simulations, alternative approaches have been adopted. One such approach is the intermittent running of such simulations to obtain shrinkage factors. The frequency at which these factors are updated shall be considered. It is generally recommended that they should be updated when:

— a specified period of time has passed since the previous update, e.g. week, month, quarter;

— a significant change in the process occurs;

— a significant change in the feed fluids occurs.

This approach risks the use of incorrect shrinkage factors in the periods between updates. This risk may be deemed reasonable if the production flows and compositions and process operating conditions are sufficiently stable.

An alternative to overcome the problems with intermittent running of process simulations is to develop correlations or look-up tables for the shrinkage factors that cover a range of production and operating scenarios. These correlations and tables can be developed based on the data generated by simulation models. They are often defined as simple functions of some salient operating parameter, such as a separator temperature. However, such correlations and tables present their own challenges:

— They are always approximations of the simulation results and hence introduce additional uncertainty.

— They can be functions of multiple variables rendering the curve fitting of correlations difficult or resulting in extensive tables. As the number of input variables increases, the amount of simulation cases required to cover all combinations of operating scenarios increases to the power of the number of variables.

— Care must also be taken to ensure correlations are not used outside the ranges over which they were fitted, that they are not overfitted and that there are not local minima or maxima in the function between data points.

The ideal approach is to integrate the simulation into the systems and operation of the allocation system.

5.4.4 Fundamentals of a process simulation model

Process simulations are a collection of methods used to study and analyse behaviour and performance of actual or theoretical systems. Formulae are used to describe the system and to derive information from it. In process simulators, the formulae describe the following relationships:

— heat balances;

— mass balances;

— vapor-liquid equilibria;

— equipment performance (e.g. compressor duties).

The software should be easily configurable so that it can model a wide range of processes. The software normally includes features to facilitate model building, for example, a graphical user interface or keyword input file to allow the model to be defined easily, including input of:

— process topology (i.e. how the various pieces of equipment are connected);

— equipment performance parameters, etc.;

— a physical property database for a wide range of compounds;

— thermodynamic methods to predict the behaviour of components;

— reporting and data transfer features.

Although such software makes the modelling of processes easier, sufficient equipment data, stream flows, compositions and process operating conditions shall be provided so that the model (i.e. the set of equations) is solvable.

5.4.5 Using process simulation models

The use of process simulation models in allocation shall not compromise the reliability, repeatability and traceability of the allocation system.

Process simulation models may appear to be 'black boxes'; input data are entered, and the results are obtained. The model shall be:

- representative and robust;
- secure, so that settings or data cannot be overwritten unintentionally;
- run from a known starting point, to reduce variations introduced by different starting points for iterative calculations. The base model should not be overwritten by the solved model.

Where hypothetical components (or pseudo-components) are used to characterize the heavier components in oil systems, the properties of the hypothetical components can be entered for each field individually. This has the advantage of setting different boiling point fractions for each field.

5.4.6 Construction of a process simulation model

5.4.6.1 General

In order to construct a model using a commercial simulation package, the following items shall to be defined:

- process flow diagram, i.e. how all the pieces of equipment are connected: this is normally entered using a graphical user interface that represents the process visually or via keyword input file;
- components to be used;
- thermodynamic package, e.g. Soave Redlich Kwong (SRK), Peng Robinson (PR), etc.;
- process input data, i.e. flows, compositions and process operating conditions;
- other relevant process equipment data if required;
- control functions and product specifications.

5.4.6.2 Process flow diagram and equipment data

Simulations are used in process engineering to assist with system and equipment design. These models can be complex as they include many items of equipment including separators, control valves, pumps etc. This complexity often leads to instability. This is not a problem when using models for design purposes. However, for allocation use, it is better to construct models with the least equipment possible to adequately model the process. This speeds up development of the model and improves stability.

When used as part of an allocation system, the simulation is generally only used to determine how hydrocarbons entering the process are distributed between the various liquid and gas products exiting the process. Stream enthalpies, equipment performances, etc. are not of interest.

The only important operations in the flow scheme are those where material streams are combined or separated. Therefore, the allocation simulation can be constructed simply as a series of flashes, mixers and splitters, provided that the operating conditions in the flashes are known or specified. The fact that there may be several equipment items between the flashes does not affect the vapor-liquid equilibria in the vessels, which are determined by the operating conditions. Equipment items which do not affect the vapor-liquid ratio shall not be included on the model, leading to a simplified process flow diagram.

5.4.6.3 Component data

The selection of components to be used in the simulation is closely associated with the selection of components to be allocated. This is discussed in Clause 4.

There are two principal types of components used in simulations:

- Library components: These are associated with single identifiable molecules, e.g. methane, ethane, carbon dioxide, for which there is recognized published data.

— Hypothetical components or pseudo components: Each hypothetical component is assigned properties such that it is representative of a mixture of molecules too numerous to identify individually. Typically, a hypothetical component represents, for example, all C_7 molecules or all the molecules found in a boiling point range from a distillation.

There should be sufficient components included in the model to adequately reflect the process being simulated. This is particularly true of the heavy end characterization.

For gases, where most of the components are light and identifiable as individual library components [up to heptanes (C_7)], the default equations of state (EOS)parameters such as critical pressure, critical temperature and acentric factor are sufficient for allocation predictions. However, for hydrocarbon liquid samples where there are significant heavy components above heptanes (C_7 and higher), measured laboratory data can be used to tune the EOS models and to improve the accuracy of the results.

5.4.6.4 Thermodynamic packages

Thermodynamic packages available in commercial simulators incorporate various EOS. EOS describe how a fluid behaves thermodynamically and should provide an accurate reflection of the behaviour of streams.

The two most commonly used EOS for hydrocarbon systems are the PR and SRK. These are based on the ideal gas equation but have additional parameters included to account for deviations from ideality. For most simulations, either of these methods is adequate.

5.4.6.5 Process input data

Typical process input data usually comprise:

— metered flows;

— measured compositions (e.g. from chromatographs and/or distillations);

— vessel temperatures and pressures.

It is preferable to obtain mass-based metered values, as mass balances across all parts of a process are an essential feature of simulations.

Redundant data may need to be reconciled before being entered into the model. For example, if all the component flows entering and leaving a process are measured, one set must be discarded as it is unlikely that the thermodynamic calculations in the model will result in precisely the same results as those measured.

5.4.6.6 Control functions

Simulations also provide functions that allow one input variable (e.g. stream rate/vessel temperature/ pressure) to be varied in order to meet a desired output rate. Similarly, the plant can be controlled to meet product specifications such as liquid true vapor pressure, Reid vapor pressure or gas superior or upper calorific value.

Such control functions are typical encountered in stand-alone or exclusion allocation approaches as discussed in 5.4.7.

5.4.7 Modelling approaches

5.4.7.1 General

The main approaches adopted regarding the use of simulations in allocation systems are described below. They are all legitimate approaches and none represents the correct approach. They simply reflect different allocation philosophies.

5.4.7.2 Commingled approach

Simulations can be used to provide information for allocation for the actual process and used directly to allocate hydrocarbons between fields. This can be termed a commingled allocation philosophy in that the impact of each field's hydrocarbons on the other fields is a necessary consequence of sharing a processing facility. The allocation of one field's allocated quantities is dependent to some extent on the flow and composition of other fields.

The consequences of this approach are that leaner fields tend to be allocated more oil and less gas than if they were processed on their own. Heavier fields are conversely allocated more gas and less oil than if processed alone.

5.4.7.3 Standalone approach

Production from a lean condensate field behaves quite differently when commingled with heavier fluids than when processed on its own.

The standalone approach attempts to allocate each field the hydrocarbons it would have produced if processed on its own. The stand-alone production of oil and gas products from each field is calculated using a process simulation. These simulated production quantities are then allocated against the actual metered quantity.

The sum of the individual produced quantities is not generally equal to the measured production from the combined fields. This is sometimes referred to as the 'effect of commingling' which is larger when field compositions vary widely. Therefore, the fields are not necessarily allocated the production equal to their stand-alone simulation predicts but are closer than with the commingled case.

5.4.7.4 Exclusion approach

Another approach determines the marginal impact each field has on the total production. This is called the exclusion, combined-minus or by-difference approach. Production is simulated, firstly with all fields flowing, and then with all fields except the field of interest. The contribution from the field of interest is calculated by determining difference between the two sets of results.

The by-difference contributions are then summed and allocated against the measured production similar to the standalone approach.

5.4.7.5 Game theory approaches

More complex approaches may be adopted that utilize methods developed from co-operative game theory. Examples include the application of the Shapley Value or the Nucleolus. They were developed based on desired properties an allocation method should have. For example, when allocating fuel gas, two reasonable properties are:

— Stand-alone: No one field shall be allocated more fuel than it would be if being processed alone.

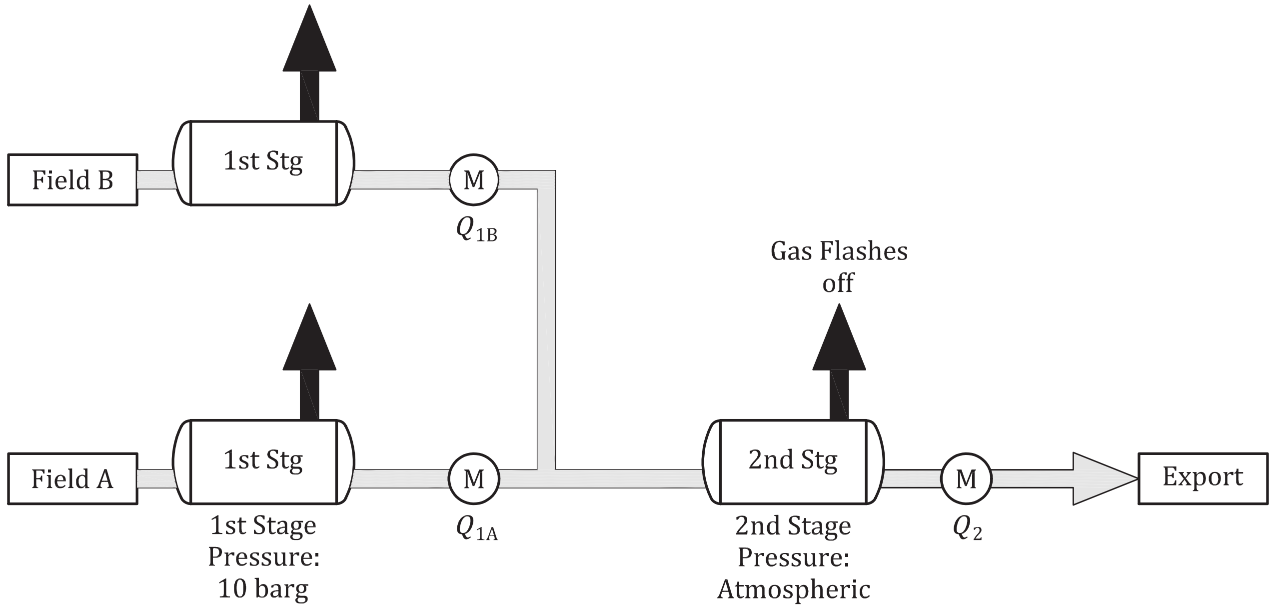
— Subsidy free: The amount allocated to a field shall be greater than the incremental increase in fuel it causes (if this is not true then the other fields subsidise the new field).

Satisfaction of these two conditions can reasonably be used to identify allocations as being fair and equitable. The economies of scale brought about by the sharing of facilities are enjoyed by all fields. These ideas are particularly relevant for fuel gas which does not necessarily vary linearly with throughput. For example, if a second compression train is started to process a new field, there will be a step change in the fuel demand.

These approaches are discussed more fully in Reference [30].

5.4.8 Example of process simulation modelling for allocation: calculation of shrinkage factors

Consider an offshore platform topsides process such as that presented in Figure 6.



Key

liquid streams

vapour streams

M flow meter

Figure 6 — Typical offshore platform process

The commingled metered export oil is to be allocated between fields A and B based on their respective first stage separator metered rates. The first stage separators are operating at 10 bar[2)] and the fluids are then transferred to a common second stage separator operating at atmospheric conditions, resulting in hydrocarbons flashing off. Therefore, the exported oil metered quantities, on a mass basis, is less than the sum of the first stage metered quantities (ignoring the impact of any meter uncertainties). To allocate equitably, it shall be established how much material is flashed from each field’s fluids in the second stage separation process.

A formula may be applied to each of the field metered quantities to estimate how much product oil remains after gas is flashed off in the second stage. This is commonly referred to as a shrinkage factor and for field A may be defined as:

$$S_A = \frac{Q_{2,A}}{Q_{1,A}}$$

where

S_A is the shrinkage factor for field A;

$Q_{2,A}$ is the field A product oil after second stage separation;

$Q_{1,A}$ is the field A product oil after first stage separation.

Quantity $Q_{2,\ A}$ is not directly available from any plant measurement, but a process simulation can predict $Q_{2,A}$, by modelling field A's fluids using a process simulation. Assuming a standalone approach is adopted, the results from such a two-stage process calculated using a simulation model can be:

$Q_{2,A}$ = 70,759 kg/h

2) 1 bar = 0,1 MPa = 105 Pa; 1 MPa = 1 N/mm^2

$Q_{1,A} = 73{,}105$ kg/h

This means that 2,347 kg/h of vapor has flashed off in the second stage separator.

The shrinkage factor for field A is then calculated to be:

$$S_A = \frac{70{,}759}{73{,}105} = 0{,}967\,9$$

Similarly, field B's shrinkage factor can be calculated. This can be different, as field B can produce a more, or a less, volatile crude, or it can experience a different temperature or pressure within its first stage separator.

The first stage metered quantities can then be multiplied by each field's shrinkage factor to obtain an estimate of individual export oil quantities. The metered export oil can then be allocated proportionately to account for the effect of commingling.

Shrinkage factors are normally expressed on a mass basis rather than a volume basis. Volumes are generally not additive, and their value is dependent on the conditions they are quoted at, e.g. standard versus actual conditions.

A range of shrinkage factors can be calculated for each field at various conditions and applied appropriately.

6 Measurements, sampling and analysis

6.1 General

Quantities of gas and condensate may be expressed, allocated or sold in units of mass, energy of combustion or volume at specified conditions of temperature and pressure. However, direct measurements are only possible for mass using mass flow meter or volume at operating conditions, and then only for single-phase fluids.

Direct measurement is not possible for most measurements of mass, all measurements of combustion energy and all measurements of volume at reference conditions of temperature and pressure other than line conditions. Volume measurements at line conditions shall be combined with measurements of other parameters depending on the composition or quality of the gas/condensate fluids.

Subclause 6.2 deals with the measurement of volume at line conditions and the direct measurement of mass, including quantity measurement in terms of the different fluids encountered in gas/condensate applications, quantity measurement in terms of the meter types available and the validation of the different types of meters. Sampling and measurement of quality for gas and condensate are dealt with in 6.3 and 6.4.

6.2 Flow measurements

6.2.1 Single-phase liquid measurement

The liquids considered in this subclause are condensate and water. These can be measured by various recognized devices and International Standards or recommended practices documents are available for some devices. Condensate from separators can contain some water due to an incomplete separation process, but normally condensate and water separate very easily. As the condensate at the exit of the separator is at gas equilibrium pressure (bubble point), any subsequent reduction in pressure causes gas breakout. This gas breakout can degrade the performance of single-phase measurement devices. To minimize this effect, the condensate should be measured with as much head as is physically practical. This requires adequate height between the measurement point and the minimum expected separator gas-liquid level.

The calculated pressure head at the measuring device shall be enough to prevent gas breakout at the measurement point due to a pressure drop across the device at maximum flow.

Condensate density, temperature and pressure should be measured as close to the primary measuring device as possible.

Gas breakout is not as critical for measuring the water stream as it is for the condensate stream. It is recommended that the measurement device be placed sufficiently below the minimum expected separator liquid level and that a full-bore measurement device, such as an electromagnetic or ultrasonic flow meter, should be used. The water flow measurement from a single separator can have a very large turn-down ratio and multiple meter runs may be required under these conditions.

The effect of temperature and pressure on the water measurements is minor compared to condensate and is normally not necessary to provide a separate stream temperature or pressure measurement.

If mono ethylene glycol or other hydrate inhibitor chemicals are part of the liquid phase, this shall be accounted for, and relevant considerations shall be done during system design and when selecting metering technology.

The following liquid flow measurement methods are suitable for metering condensate or water:

— Coriolis meters;

— turbine meters;

— multipath ultrasonic meter;

— vortex meters;

— tank-level measurement.

These methods are well described in industry standards so are not discussed in detail in this document. For flow meters, it can be advantageous to utilize meter diagnostic suite available with the chosen metering system. Such systems can identify gas break out as well as other meter malfunctions.

6.2.2 Multiphase measurements

This term is used to denote measurements to perform on multiphase streams, i.e. streams with presence of gas and liquids flowing together.

Average liquid or gas fractions are characterized by liquid volume fraction (LVF) or gas volume fraction (GVF) as per ISO/TS 21354 and ISO/TR 12748.

There are presently few techniques available that can measure this type of fluid regime to a high degree of accuracy.

Gassy liquids are liquids that contain small amounts of gas. Generally, the GVF of these fluids is in the range of 0 % to approximately 25 %. Single-phase meter behaviour is not predictable and damage to certain meter types can occur.

6.2.3 Gas measurement

6.2.3.1 General

For the custody transfer measurement, the method and principles should ensure as low measurement uncertainty as practically possible.

In allocation measurement systems he individual systems shall be similar and treated equally. For example, flow sampling of different input streams by a common test separator should result in fair and representative allocation for the interest owner.

Dry-gas flow measurement should be performed using methods and standards that are generally accepted by the oil and gas industry and which shall be mutually agreed upon by the parties that have interests in the allocation.

Equilibrium gas is defined as separated gas that has no free liquids but can develop a small liquid content by changes in process conditions or meter/pipe-work interaction. Any process changes of the gas can cause a shift in the characteristics of the gas as wet or dry.

Some equilibrium gas can be wet due to liquid entrainments in inefficient separators.

The measurement devices used for dry gas applications can be used for equilibrium gas. However, in the design, care should be taken as soon as liquids start to form (e.g. due to pressure drop in the meter) and the effect on the reading should be established.

The gas flow metering methods described in 6.2.3.2 to 6.2.3.5 are used most often for single-phase and equilibrium gas flow rate measurement, but other methods are not excluded.

6.2.3.2 Multipath ultrasonic meter

For information on ultrasonic meters for gas, see ISO 17089-1 for custody transfer and allocation applications and ISO 17089-2 for industrial applications.

The ISO 17089 series specifies requirements and recommendations for ultrasonic meters (USMs) for gas, which utilize acoustic signals to measure the flow in the gaseous phase in closed conduits. The ISO 17089 series specifies performance, calibration and output characteristics of USMs for gas flow measurement and deals with installation conditions.

USMs may, by special design, tolerate small amounts of entrained liquid. A USM vendor should be consulted for application evaluation for such cases as no published wet gas corrections are available for ultrasonic meters. Potential risk issues are liquid blockage of transducer ports, high signal attenuation, material combability between hydrocarbon liquid and any non-metallic material.

As per ISO 17089-1:2019, Clause 8, ultrasonic meters have comprehensive diagnostic suites that facilitate condition-based monitoring maintenance.

6.2.3.3 Differential pressure devices

Gas flow measurement for custody transfer (also referred to as fiscal metering) by means of orifice plate differential pressure (DP) devices shall be according to ISO 5167-1 and ISO 5167-2 using a square edge orifice plate with flange tapings installed in a meter run. ISO 5167-1 and ISO 5167-2 give detailed guidance on design, installation, diagnostic and flow computation.

Orifice meters operated in accordance with the ISO 5167 series do not require flow calibration.

The ISO 5167 series describes other differential pressure metering devices such as Venturi-, nozzle-, cone- and wedge-meters. Both Venturi and cone-meters can also be used for allocation. Standards should be referred to when using such systems in allocation systems.

Equilibrium gas can cause liquid drop out and block liquid transport at low flowrates in horizontal pipes, orifice and Venturi type meters. ISO/TR 15377 provides guidelines for the specification of orifice plates, nozzles and Venturi tubes beyond the scope of the ISO 5167 series. It also covers the use of drain holes that can alleviate fluid hold-up. Errors arising from the presence of liquid are not described in ISO/TR 15377.

ISO/TR 11583 describes general wet-gas correction equations compensating for the wet gas.

Wet gas correction methods in oil and gas industry for single phase gas flow meters are described in ISO/TR 12748. ISO/TR 12748 covers the measurement of wet gas flow, i.e. terminology, models, principles, design, implementation, testing and operation of wet gas flow meters.

Differential pressure meters have comprehensive diagnostic suites that facilitate condition based monitoring maintenance regimes (see ISO 5167-1:2022, 5.6.4).

6.2.3.4 Coriolis meter

ISO 10790 provides general guidelines for Coriolis meters. Coriolis meters may also have a diagnostic suite that facilitates a condition based monitoring maintenance regime, (see ISO 10790:2015, 4.7).

Liquid droplets can stick to the inner pipe wall. This can affect the performance of the Coriolis meter. When using a Coriolis meter under wet gas conditions, a vendor should be consulted since there are no published Coriolis meter wet gas correlations available.

6.2.3.5 Turbine meter

A turbine meter uses a spinning propeller to infer volume flowing through a meter run. ISO 9951 specifies dimensions, ranges, construction, performance, calibration and output characteristics of the turbine meters for dry gas.

Turbine meters are generally not intended to be used in systems with wet gas or gas at equilibrium with liquid drop out potential.

6.2.4 Wet gas and multiphase fluids

6.2.4.1 General

This term is used to denote a natural gas flow containing a relatively small amount (up to about 10 % by volume) of free liquid. There are presently few techniques available that can measure this type of fluid regime to a high degree of accuracy.

A comparison study of ultrasonic metre (USM) and DP devices response to wet natural gas provides test results and considerations utilizing USM and DP technology for wet gas: see Reference [32].

Supporting information can be found in Reference [33].

Currently, the following gas-flow metering methods are most used for wet-gas flow rate measurement:

a) DP devices:

   1) Venturi meter

   2) cone meter

   3) orifice meter

   4) wedge

b) dedicated wet gas flow meters (WGFM)

The combination of differential pressure devices with different sensitivities to liquid content are not discussed further in this document. Refer to ISO/TR 12748.

c) multiphase flow meters (MPFM)

Some meters have an extended range into the wet-gas flow region.

Currently the following gas flow methods are not considered suitable for wet gas flow rate measurement:

d) USM

At present, USMs are not suitable for measuring gas above 0,5 % LVF as the units produce unstable readings.

6.2.4.2 Flow sampling/test separator

Using a test separator to establish a well performance curve is an example of flow sampling. Well performance is normally checked at regular intervals. Well production as a function of wellhead pressure with critical choke flow is established.

6.2.4.3 Clamp-on technology

Clamp-on metering technology can be a cost-efficient alternative for certain application as well as allocation systems with missing instrumentation.

A clamp-on sensor alone or in combination with a DP meter is applicable technology for wet gas; see References [33] and [34].

6.2.5 Indirect methods

Cost, limited financial allocation consequences for users and other conditions can result in the use of simplified methods to establish input quantity. It is possible that there are certain limitations to establishing an indirect measurement of input stream.

6.2.6 Virtual metering

Other categories of single-phase or multiphase metering systems include signal processing systems flow estimation (“virtual”) systems which can be used to estimate flow rates and phase fractions from computation and modelling of the signals from whatever sensors are available. Such sensors may be acoustic, pressure or other types. Even if virtual metering systems uncertainty is generally considered to be higher than specific hardware solutions, virtual metering systems are applicable on a case-by-case basis for technical allocation or contractual allocation if mutually agreed.

The signal processing can be a neural network or other pattern-recognition or statistical signal-processing system, for example.

These systems are complementary to MPFM and WGFM and rely on routine tuning or calibration against the MPFMs in service. Multiphase metering systems have also been developed based on process simulation programs combined with techniques for parameter estimation. Instead of predicting the state of the flow in a pipeline at the point of arrival, pressure and temperature can be measured at the arrival point and put into the simulation program. In addition, the pressure and temperature at an upstream or downstream location should also be measured. When the pipeline configuration is known along with properties of the fluids, it is possible to make estimates of phase fractions and flow rates.

To some extent, well flow rates estimations using performance curves are virtual metering systems.

6.2.7 Measurement uncertainty

The uncertainty calculation of the measurement installation shall be based on the relevant and recognized methods such as ISO/IEC Guide 98-3.

There is no standard solution as to what measurements are required. However, it is important to understand the effects of the different options on the system uncertainty, so that an informed decision can be taken.

For any allocation system, the uncertainty of the system is directly related to the uncertainty of the inputs, whether they are measurements or estimates. Most systems have accurate, fiscal quality measurement of the export streams. However, each partner is ultimately paid for the allocated exports, and these are based on other, often less accurate input measurements. The allocation system and process are designed to impart the higher accuracy of the fiscal quality measurement on to the measurements of the input streams and therefore reduce the risk of the various interest owners in the commingled flow process.

However, no matter how robust the allocation method, if there is a high level of uncertainty in the measurements, the allocated quantity results will have a high level of uncertainty. However, as always, a compromise is necessary. Improved measurement reduces allocation uncertainty but also increases costs. The nature of allocation is that there can be no overall gain for the whole facility. Reducing uncertainty reduces the risk of exposure to bias for any one user but does not increase overall revenue.

Users should be aware of possible limitations in the operational conditions, including the correlations and models used.

6.3 Sampling

6.3.1 General

Sampling and analyses of process fluids is part of the allocation process. Samples are taken for the following analyses in the allocation process:

— quality analyses, to obtain the energy content of the hydrocarbons for sales purposes and properties for volume or mass measurements;

— evaluation analyses, to obtain the economic value of the hydrocarbons;

— PVT analyses for process simulation.

The analytical results depend on the method of sampling and on the process conditions at which the sample is taken. Furthermore, one should always be aware that a (spot) sample is only a snapshot and that samples are not always representative for a continuous process.

6.3.2 Single phase gas

The sampling of single-phase gas allows a representative sample to be obtained. The following requirements related to spot sampling shall be met:

— flush the sampling system with process gas from the pipeline under process operating conditions in order to remove contamination and equalize the temperature of the sampling system;

— ensure that no condensation of the sample gas occurs due to the length of the sampling lines or from a drop-in pressure or temperature. Gas shall be kept 5 to 10 °C above expected liquid condensation temperature;

— use of sampling probe.

Comprehensive gas sampling guidelines and requirements are given in ISO 10715.

6.3.3 Single-phase liquid

The method used for sampling condensate is highly dependent on its purpose. If the full compositional data of the condensate is required for PVT analysis, reallocation purposes or LPG composition, the sample shall always be taken at process operating conditions. This requires, in most cases, a pressurized sample. The preferred method of taking a pressurized sample is with a bottle with an expansion compartment.

To obtain a sample, the sampling system shall first be flushed with condensate from the pipeline under process operating conditions, in order to remove contaminants, and then be filled with the representative fluid. The flushing and/or filling of the bottle or bomb shall be executed slowly and with great care to prevent evaporation of the sample in the sample system, which can influence the composition of the condensate sample. For specific requirements related to liquid petroleum sampling, reference is made to ISO 4257.

In some cases, condensate samples can also be taken at atmospheric pressure. This means that the sample is brought to atmospheric conditions from whatever the process operating conditions were. Consequently, if the process temperature and/or pressure are elevated, the composition of the condensate can change due to evaporation of the lighter components. This method, however, is applicable if there is no requirement for full compositional data for the condensate at elevated operating conditions (e.g. for cloud point or pour point determination).

6.3.4 Wet gas sampling

It is challenging to obtain a representative sample containing all components of the full fluid flow by direct sampling of wet gas in multiphase state. A representative sample can be determined only by sampling the individual phases after separation and recombining the analyses in proportion to the respective flows.

For specific requirements related to gas and liquid sampling, reference is made to ISO 10715 and ISO 4257.

A representative range of all components of the full fluid flow can be determined only by sampling the individual phases after separation and recombining the analyses in proportion to the respective flows. The recombination can be based on the individual flows from gas-liquid ratio from gas and liquid separator measurements during the sampling.

The recombined result, using the gas-liquid ratio, normally represents a compositional analysis with a low accuracy, especially for components that are in equilibrium between the gas and liquid phases under the sampling conditions. For many cases, this is the component range C_5 to C_{10}. Therefore, manual or continuous sampling can be reliably performed only for a limited range of the composition or one particular component in one phase.

When a separator is not available, a recombination analysis can be made based on a flow determination by means of the tracer-dilution technique.

The use of a sample probe is strongly recommended. For sample recovery, the probe shall be positioned as isokinetically as possible relative to the required phase in the flow. This improves the representativeness of the sample.

To keep costs down, some allocation procedures may make use of wet-gas sampling. The consequence is a higher uncertainty of the overall allocation process, mainly caused by the samples not properly representing the entire flow. This can only be accepted if contracting parties are fully aware of the implications.

6.3.5 Multiphase sampling

Samples from multiphase flow lines suffer from the same weak representativeness as wet-gas samples. All aspects mentioned under wet-gas sampling are largely valid for multiphase sampling. Only those components that are guaranteed in either the gaseous phase or the liquid phase under the sampling conditions can be determined with reasonable accuracy.

Because of the lack of representativeness of the sample, the accuracy of the analytical results can be poor. It is therefore not recommended to use the results of multiphase sampling in the allocation process.

6.3.6 PVT sampling

In practice, this means taking samples of equilibrium gas and equilibrium liquid from points close to the measurement point. To obtain the best estimate of full-stream composition, it is necessary to determine the flow rates of gas and liquid at the sampling points. These may be measured at intervals elsewhere in the system, e.g. at a separator, probably at pressures and temperatures different from those at the wet-gas measurement point. This requires making corrections for changes in composition to adjust the liquid and gas flow rates to those at the wet-gas measurement point.

6.3.7 Considerations on sampling points

For the collection of gas samples, a sample point including a probe shall be installed downstream the straight lengths of the wet-gas meter. Where the liquid-gas ratio is determined by means of a tracer technique, sample injection and collection points shall be made available.

The injection point shall be located at a sufficient distance upstream of the measurement element to allow adequate mixing of the tracer with the liquid phase. The collection point shall be located in the bottom of the flow line downstream of the primary element.

Where the wet-gas meter can be put in series with a test separator, gas and liquid flow rates may be measured and samples may be taken at the test separator. Gas and liquid properties may be derived by means of a flash calculation.

6.3.8 Sampling of gas containing sulfur compounds

Sulfur compounds in natural gas are toxic. Personal protective equipment is required in accordance with ISO 10715 when sampling.

6.4 Analysis

6.4.1 Wet gas composition analysis

Sample analysis can take place only on one phase at a time. Therefore, the phases shall be fully separated. For continuous sampling, this requires a sampling conditioning system designed to pass only the required phase. When dealing with spot samples, the phases (liquid and gas) shall be carefully pre-conditioned, separated (in the sample bottle) and analysed separately. Then the two phases may be combined on a mass-weighted basis to create a complete analysis of the sample.

6.4.2 Gas chromatographic method for compositional analysis

The range of components for analysis shall be determined in advance and depends on the purpose of the analysis. In general, an analysis in accordance with the ISO 6974 series is sufficient for dry gas components. An analysis in accordance with ISO 6975 provides a much wider range of components and is suitable for equilibrium gas or condensate components.

Gas chromatographs operate at atmospheric pressure, so the sample shall be heated prior to pressure reduction. Also, the gas shall remain above the dew point at the operating temperature of the gas chromatograph.

6.4.3 Laser Raman spectroscopy and infrared spectroscopy method

Besides the gas chromatography method, the laser Raman spectroscopy and infrared spectroscopy method can also be used for compositional analysis in some cases.

6.4.4 Analysis for geochemical fingerprinting

This technique uses a multi-dimensional gas chromatographic analysis to determine quantitatively the concentration of the aromatic compounds within the C_8 to C_{10} range of a sample of the hydrocarbon reservoir fluid. The relative proportions of the aromatic components in this range are usually unique to a reservoir, giving the reservoir fluid a unique signature.

For the method to be viable, it is necessary that aromatic compounds in the C_8 to C_{10} range be contained in the composition of the product from each of the contributing fields. It is also necessary that there be sufficient difference in the relative amounts of some of the components of the contributing fields to enable the field product ratios to be established, i.e. if the geochemical signature for two contributing fields is very similar then the method does not work.

6.4.5 Sulfur content analysis

The methods for analysis of hydrogen sulfide or total sulfur in natural gas can refer to ISO 11626, ISO 19739, ISO 20676, ISO 16960 and ISO 20729.

The determination of sulfur content in petroleum products (condensate) can refer to ISO 16591.

6.4.6 Water content analysis

A method for water content is given in ASTM D4377.

6.4.7 Analysis of gaseous water

For the method for analysis of gaseous water content in natural gas, refer to ISO 10101 and ISO 11541.

6.4.8 Analysis of liquid water fraction

(1) Near-infrared method

Determination of water in gas/condensate streams is often important to prevent corrosion or hydrate formation in pipelines. Increasingly, near-infra-red methods are being used or developed for these applications. Water determination by infra-red absorption is difficult because the absorption peaks of water and major hydrocarbon components overlap. Photo-acoustics, in which the relative absorption by water compared to hydrocarbons is greatly enhanced, and the absorbed infra-red radiation is converted to ultrasound for detection, can potentially provide better instruments for this application.

(2) Multiple-energy gamma ray spectroscopy method

By using a source that emits gamma rays with two or more different energies, one can use attenuation measurements made at these distinct spectral lines as input to a model of the multiphase fluid to obtain the relative fractions of oil, water and gas present. Several meters have been developed that use gamma ray spectroscopy for phase fraction estimation.

6.4.9 Water-liquid ratio for liquid

There are two main options to determine water content or water-liquid ratio in liquids (e.g. hydrocarbon condensates, oil, methanol).

One option is to perform offline analysis using centrifugation, distillation, or Karl-Fischer[39] on liquid samples.

A second approach is to use online water fraction measuring systems based on one of the following principles:

— electrical measurements;

— near-infrared method;

— density measurements;

— speed of sound.

6.4.10 Determination of particles content

There is no ISO standard on the determination method for particles content. The gravimetric method is recommended in some national standards.

6.4.11 Wet gas physical parameters measurement

Wet gas physical parameters, such as density, compression factor, speed of sound and calorific value, can be calculated from pressure, temperature, and composition according to the relevant standards. Compositional analysis in accordance with ISO 6975 is preferred for the calculation of these physical parameters.

6.4.12 Density

The density of wet gas fluid can be measured by the method according with ISO 15970 or using the single-energy gamma ray densitometry introduced in the chapter 20.3 of API Manual of Petroleum Measurement Standards. The density of natural gas can be calculated in accordance with the method described in ISO 6976 or ISO 20765-1 by taking the pressure, temperature and composition as the input.

The density of condensate can be calculated in accordance with the method described in ISO 20765-2 or ISO 8973, by taking the pressure, temperature and composition as the input.

Density of condensate and more generally can also be determined by online system like specific densitometers or Coriolis based systems.

6.4.13 Compression factor

The compression factor of natural gas can be measured by the method according with ISO 15971.

By using the method according to ISO 12213 or the ISO 20765 series (all parts), the compression factor of natural gas can be calculated by taking the pressure, temperature and composition as the input.

6.4.14 Speed of sound

By using the method according with the ISO 20765 series (all parts) or AGA Report 10[40], the speed of sound in natural gas can be calculated by taking the pressure, temperature and composition as the input.

6.4.15 Calorific value

The measurement of calorific value (gross calorific value or net calorific value) of natural gas can use the method according to ISO 15970.

By using the method according with ISO 6976, the calorific value of natural gas can be calculated by taking the composition as the input.

7 Allocation principles

7.1 General

In a hydrocarbon value chain, there can be several comingle- or split points related to processing or transportation. The properties and value of the fluid changes after each point. The change should be calculated and documented by adequate (quantity) measurements, (quality) sampling or simulation calculations.

A hydrocarbon flow stream consists of several products. The value of the fluid is dependent on the product composition. If the hydrocarbons at the end of the value chain are sold by single products or energy, the components or the GCV shall be tracked through the value chain.

The theoretical principle for any allocation is that balance across systems can be close. This means the amount of mass going in shall be the same amount of mass coming out of a common process or transportation system. However, in practice there is always a difference between the incoming and outgoing measured amounts. This can be due to measurement uncertainty, time factors, change in pressure and temperature.

If the difference between the ingoing and outgoing measurement points has a significant impact on the allocated amounts, the differences shall be accounted for; balancing and reconciliation shall be performed.

7.2 Allocation methods

As per Clause 4, the following allocation methods can be used:

— allocation by pro-rata;

— allocation by difference;

— allocation by process simulation with flash calculations;

— uncertainty-based allocation.

Pro-rata allocation is often used. However, in some applications, the allocation is carried out by difference or by other methods.

In some complex value realization chains, there can be a combination of the different methods or allocation in several steps or groups (see Figures 2, 3 and 4).

There are multiple combinations of allocation applications, methods and calculations based on contractual agreements. In this document, the methods are covered in 7.4 to 7.10.

7.3 Allocation units for gas allocation

Allocation can be performed in energy, mass or volume. Allocation based on energy or mass by hydrocarbon components are the most comprehensive. Allocation by volume is generally not recommended for contractual allocation but can be accepted when allocation by mass is not possible or the products or energy has minimal affiliation. An example is well allocation and utility gas allocation, where mass measurement is difficult and representative sampling of the flare is not possible. If the flare gas is a small share of the utility gas consumption, it may be assumed that the flare gas composition is equal to fuel gas composition or use an agreed density to convert volume to mass.

Based on the fluid quantity measurements, fluid quality analysis results and/or fluid property knowledge, allocation calculation and computation can be composed based on the following principles:

$$E_\mathrm{i} = M_\mathrm{i} * G_\mathrm{im} \text{ or } E_\mathrm{i} = V_\mathrm{i} * G_\mathrm{iv}$$

$$M_\mathrm{i} = M * C_\mathrm{i}$$

$$V = \frac{M}{\delta}$$

where

E_i is the energy i;

M_i is the mass i;

V_i is the volume i;

G is the gross calorific value.

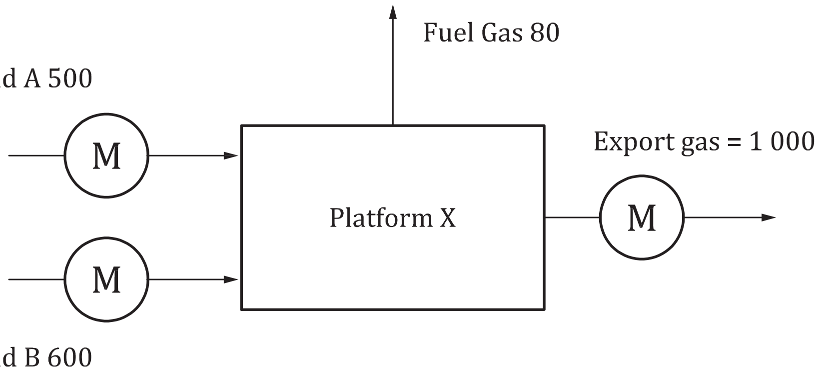
7.4 Proportional allocation

7.4.1 General

Proportional allocation or pro-rata allocation allocate products to input streams in proportion to their contribution.

Figure 7 illustrates a case of proportional allocation in which a gas product in arbitrary units is allocated to A and B inputs based on their contributions.

Pro-rata allocation can be extended to any number of users and can be deployed from simple volume pro rata used for well allocation to uncertainty-based approaches.



Key

M measurement

Figure 7 — Proportional allocation

Gas allocated to $I\,X(\mathrm{A},\mathrm{B}) = G\mathrm{product} \times I\mathrm{Xcontribution}$ as per Table 8 with:

$$I\mathrm{Xcontribution} = \frac{X\mathrm{gasinput}}{S\mathrm{ofgasinputs}}$$

Another way to express gas allocated to Input X is to use the allocation factor (A_F) defined as:

$$A\mathrm{F} = \frac{G\mathrm{product}}{\sum IX}$$

where

I is the input;

X = A, B;

s is the sum;

G is the gas;

A_F is the allocation factor.

With this formulation, the gas allocated to $I\,X$ (A, B) is as follows:

$$I\,X(A,B) = I\,X(A,B) \times A\mathrm{F}$$

Table 8 — Proportional allocation

Product	Contribution
Input A	500
Input B	600
Fuel gas	80
Export gas	1 000
∑ Input X (for X = A, B)	1 100
Gas product	1 080
Gas allocated to input A	490,9
Gas allocated to input B	589,1

Direct pro-rata allocation is performed using directly available measurements which may be either volume, mass or energy. This approach is relevant when dealing with systems involving generally one fluid not submitted to phase changes in which composition shall not be considered for allocation.

A typical example is a gas terminal that receives and processes gas from fields A and B prior to export as per Figure 8 and Table 9.

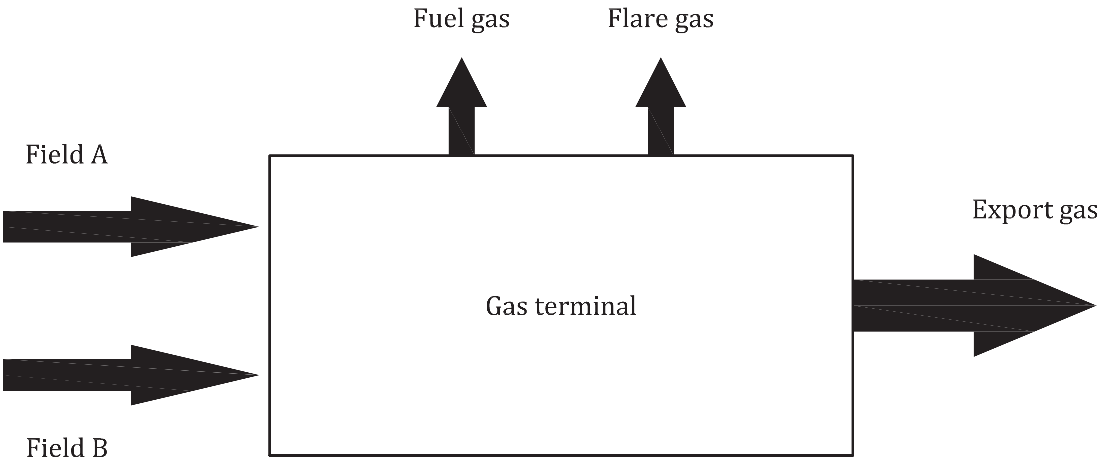


Figure 8 — Gas terminal with two incoming gas fields

Table 9 illustrates a gas terminal mass allocation with fuel and flare gas masses allocated to fields A and B in proportion of field productions.

Table 9 — Direct pro-rata gas terminal allocation example

Product	Contribution
Field A gas production	10 000
Field B gas production	20 000
Terminal gas export	27 000
Fuel and flare	1 800
Terminal gas production	28 800
Imbalance	−1 200
Fuel and flare gas allocated to field A	600
Fuel and flare gas allocated to field B	1 200
Field A net gas contribution	9 400
Field B net gas contribution	18 800
Terminal gas export mass allocated to field A	9 000
Terminal gas export mass allocated to field B	18 000

7.4.2 Pro rata based on estimations

In some cases, especially when input streams *j* are subjected to phase changes and give several products, allocation is based on the estimation of the final products attached to each input.

Such estimations are usually calculated by process simulation.

This is typically the case of a system receiving either oil and gas or hydrocarbon from a given installations X and producing dry gas and stabilized crude oil.

Performing allocation on mass basis can be performed by prorating products based on Formula (3):

$$\left(m^X\right) = \frac{\left(m_S^X\right)^{\text{est}}}{\sum_j \left(m^j\right)^{\text{est}}} \times (m) \tag{3}$$

where

m	is the mass of final product;
$(m^X)^{es}$	is the estimated mass of product for a given input stream, X;
$(m^j)^{est}$	is the estimated mass of product for each input stream, j;
(m^X)	is the mass of final product allocated to input X.

Similar pro rata equations can be developed for volumes or energy.

7.4.3 Component mass pro rata

Mass-component allocation is one of the preferred allocation methods when used on systems that deliver both gas and hydrocarbon liquids through the same pipeline. This process accommodates the exchange of components between the gaseous and liquid phases that take place in the shared treatment and transportation facilities.

The mass component allocation process involves the following steps:

a) measurement of all streams by mass *m*;

b) determination of component mass fraction per stream using either analysis or estimations.

The number of components used within the analysis is determined by the composition of the gas. Gas that contains a high proportion of hydrocarbon liquids requires a more detailed analysis. As a minimum, the components C_1, C_2, C_3, n-C_4, iso-C_4, iso-C_5, n-C_5, C_6, C_7, C_8, C_9, N_2 and CO_2 should be used (lumping the higher hydrocarbons together):

c) determination of component mass flow for of all streams;

d) pro rate each component of the fluid flowing through a delivery point against the entry point component quantities using Formula (4):

$$m_f^X = m_f \times \frac{\left(C_{f,X} \times m_X\right)}{\sum_j \left(C_{f,j} \times m_j\right)} \tag{4}$$

where

m_f	is the mass rate of fluid delivered;
m_X	is the mass rate of inlet stream X;
$C_{f,X}$	is mass fraction of component f in inlet stream X;
m_j	is the mass rate of inlet stream j;
$C_{f,j}$	is mass fraction of component f in inlet stream j;
m_f^X	is the mass rate of component f in delivered fluid allocated to inlet stream X.

7.5 Allocation by by-difference

A less comprehensive allocation method is the "by-difference" method. This method is recommended when the investment in a metering system is not justified related to the value of the income or possible losses over time. Due to the possible losses, since the non-measured field hold the total allocation uncertainty and reconciliation, this method is generally sustainable only if the non-measured field production is more than 70 % of the total production.

Allocation by difference is where the non-measured-field B production Q_2 is determined by the difference between the total outgoing stream measurements Q and Q_1 the measured/estimated outgoing share of the incoming measured field A.

The outgoing share of the incoming measured field(s) can be calculated if the asset/hub has adequate measurements and the assumption that flare and fuel have known or deemed component composition.

$$Q_2 = Q - Q_1$$

where

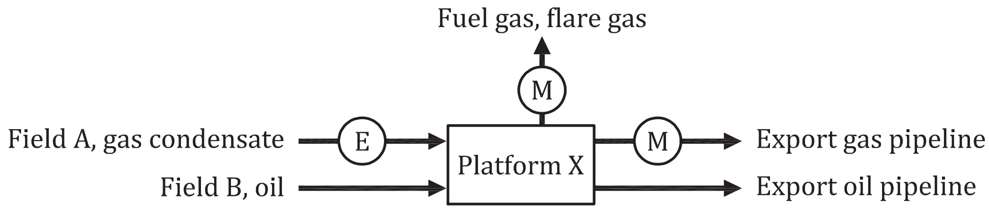
Q is the total quantity in stream to be allocated;

Q_1 is the known quantity for user 1;

Q_2 is the quantity allocated to user 2.

Quantity Q and Q_n should be in the same units and any unit basis (mass, volume, component mass, energy) can be used.

This method is illustrated in Figure 9.



Key

E estimate (e.g. from well testing)

M measurement

Figure 9 — Allocation of produced gas from installation X

Simulation is often used to establish recovery, separation and flash factors based on the incoming measurements, analysis results and process parameters. This simulation can be done either by an integrated or by a standalone simulation program using specific PVT software. These simulations require a selection of an appropriate equation of state for the flashing conditions, simulating a single flash or a multistage flash on a single or comingled stream.

If lift gas is used in the system, the lift gas shall be included in the flash calculation to give the correct equilibrium situation in the separator for the flash calculations.

7.6 Allocation by process simulation

Process simulation models can be used to estimate hydrocarbon behaviour within a process plant. Clause 5 describes the features and capabilities of process simulation models and some of the techniques used to assist allocation. This subclause describes the use of process simulation models to directly allocate components to a specific field at any point in the process. Reference is made to a field in the discussion in this subclause, but it equally applies to a well, source or any identified entity that is being allocated.

A process simulation model can be used to model the flow of all streams through an entire process and, using tagged, (or cloned), components, to identify the destination of the components supplied by each field. The model calculates the quantity of each field's feed in each product stream, therefore all the data required for allocation reporting are available. However, as the model only converges within a certain tolerance, the simulation results should be normalized against metered values.

Simulation based allocation systems can produce unexpected results. For example, recycled streams (including gas lift) can distribute components from all fields throughout the process. This can lead to product streams that can at first sight appear as though they are allocated to a single field, including components from other fields.

Process simulation models are often treated as "black boxes". Adequate quality control procedures shall be in place to ensure that the inputs and the model used are correct, and that the calculations have converged satisfactorily.

Under certain circumstances, identical results can be achieved by allocating each component in a product stream in direct proportion to the quantities of that component supplied by each field in the feed to the whole process. This only applies if the fields' feed streams are completely commingled at the inlet to the process, for example in a separator.

Clones of a component behave identically, and at the same temperature and pressure have the same K factor (ratio of mole fraction in the vapor and liquid phases). Hence, when commingled in a vessel, the normal components (e.g. methane, propane, hexane, nitrogen) for each field have the same K factor. If it is assumed that this is extended to the heavier hypothetical components, it can be proved that the ratio of each field's cloned component in the vapor and liquid product streams is directly proportional to their ratio in the feed stream. Indeed, this can be extended to a series of vessels and include recycle streams. Therefore, across a whole process, if the final product streams are allocated in proportion to the inlet rates of each field's components, this produces identical results to a full-blown simulation using cloned components. The clones of the heavier hypothetical components shall have the same or sufficiently similar K factors for all the fields.

The process should be simulated to confirm if this component pro rata approach is appropriate. Failure to conform to the common feed point and similarity of the heavier component clones invalidates the approach.

7.7 Uncertainty based allocation

Uncertainty-based allocation (UBA) is highly specialized. It requires a detailed understanding of uncertainty in the system. However, where the accuracy of input data varies significantly, it can provide a more equitable result than other methods.

UBA attempts to minimize the effect of uncertainty on the allocation. The theory of uncertainty, and how to determine the uncertainty of a value calculated within an allocation system, is discussed in Clause 11.

The system gives more weight to input meters with lower uncertainty, which results in an allocated value closer to the input measured value for these meters.

One method is to minimize the weighted sum of squares of difference between allocated and measured or estimated (e.g. by well testing) quantities, subject to the constraint that allocated quantities sum to metered product.

This is a relatively simple form of UBA and was chosen to provide a simple representation of the aims of UBA. However, this method has been implemented in real allocation systems.

There are a number of variations in the method by which the product meter uncertainty contribution to the imbalance is allocated. API RP-85[41] presents one of these variations. As the product meter uncertainty reduces, the methods converge.

The typical equations that apply to the proportional allocation are:

$$I_{\mathrm{B}} = Q - B_1 - B_2$$

$$\beta = \frac{U_1^2}{U_1^2 + U_2^2}$$

$$Q_1 = B_1 + \beta * I\mathrm{B}$$

$$Q_2 = B_2 + (1 - \beta) * I\mathrm{B}$$

where

I_B is the imbalance in system;

Q is the quantity in stream to be allocated;

Q_n is the quantity allocated to user n;

B_n is the measured or estimated quantity for user n;

U_n is the absolute uncertainty of measured or estimated quantity for user n.

Beta is the ratio of the square of the absolute uncertainty for user n over the sum of the squares of the absolute uncertainties for all users and is defined in equations above.

For example, assume that in a proportional allocation application as described in 7.4.1, the uncertainty of the field gas estimates was the same for both fields, at 5 %. Table 10 applies uncertainty-based allocation to this illustration:

Table 10 — Uncertainty-based allocation of produced gas from Platform X

Inputs	Quantities, *Q* or *B* (tonne/d)	Relative uncertainty of quantity, Ɛ (%)	Absolute uncertainty, U_n (tonne/d)
Measured export gas	2 400		
Measured fuel gas	300		
Measured flare gas	221		
B_1 field A estimate	2 175	5	108,8
B_2 field B estimate	733	5	36,7
Calculations			
Q, produced gas	2 921		
I_B, imbalance in system (see 7.7)	13		
β, ratio of uncertainties (see 7.7)	0,898		
Q_1, produced gas allocated to Field A (see 7.7)	2 187		
Q_2, produced gas allocated to Field B (see 7.7)	734		

UBA gives different allocated quantities than those obtained by proportional allocation, even though the field estimates have the same relative uncertainty of 5 %. This is because the uncertainty-based method allocates the imbalance between fields according to the variance (square of absolute uncertainty) of the measurements, while the proportional method allocates the imbalance in direct proportion to the estimated flowrates. The allocated quantities are only the same for the two methods if the estimated flowrates for both fields are the same and they have the same relative uncertainty.

The uncertainty of allocated quantities is discussed in Clause 11.

7.8 Geochemical fingerprinting

Geochemical fingerprinting is a technique that can be used for product allocation between two or more contributing fields whose product can be commingled for production and transportation. It has been used in a continental shelf development in the North Sea. It was developed mainly for oil fields but is, in principle, also applicable to gas condensate fields.

This technique uses a multi-dimensional gas chromatographic analysis to determine quantitatively the concentration of the aromatic compounds within the C_8 to C_{10} range of a sample of the hydrocarbon reservoir fluid. The relative proportions of the aromatic components in this range are usually unique to a reservoir, giving the reservoir fluid a unique signature.

The technique determines the relative amounts of these components in commingled production from different fields by analysing a representative sample. The results of this analysis are compared with a previously prepared mixing model that is generated from the analysis of samples from the individual contributing fields. The resultant component ratios, plus a flow-quantity measurement of the combined product stream, allow the determination of the quantity contributed from each field by prorating the total flow according to the geochemical component ratios.

For the method to be viable, aromatic compounds in the C_8 to C_{10} range shall be contained in the composition of the product from each of the contributing fields. There shall also be sufficient difference in the relative amounts of some of the components of the contributing fields to enable the field product ratios to be established, i.e. if the geochemical signature for two contributing fields is very similar then the method does not work.

7.9 Conversion calculation

7.9.1 Mass allocation conversion into volume

It can be necessary to calculate an associated volume for attribution, accounting and reporting purposes. The allocated mass figures can be readily converted to volume by dividing by the density of the stream in question. The method illustrated in the Figure 10 may be utilized.

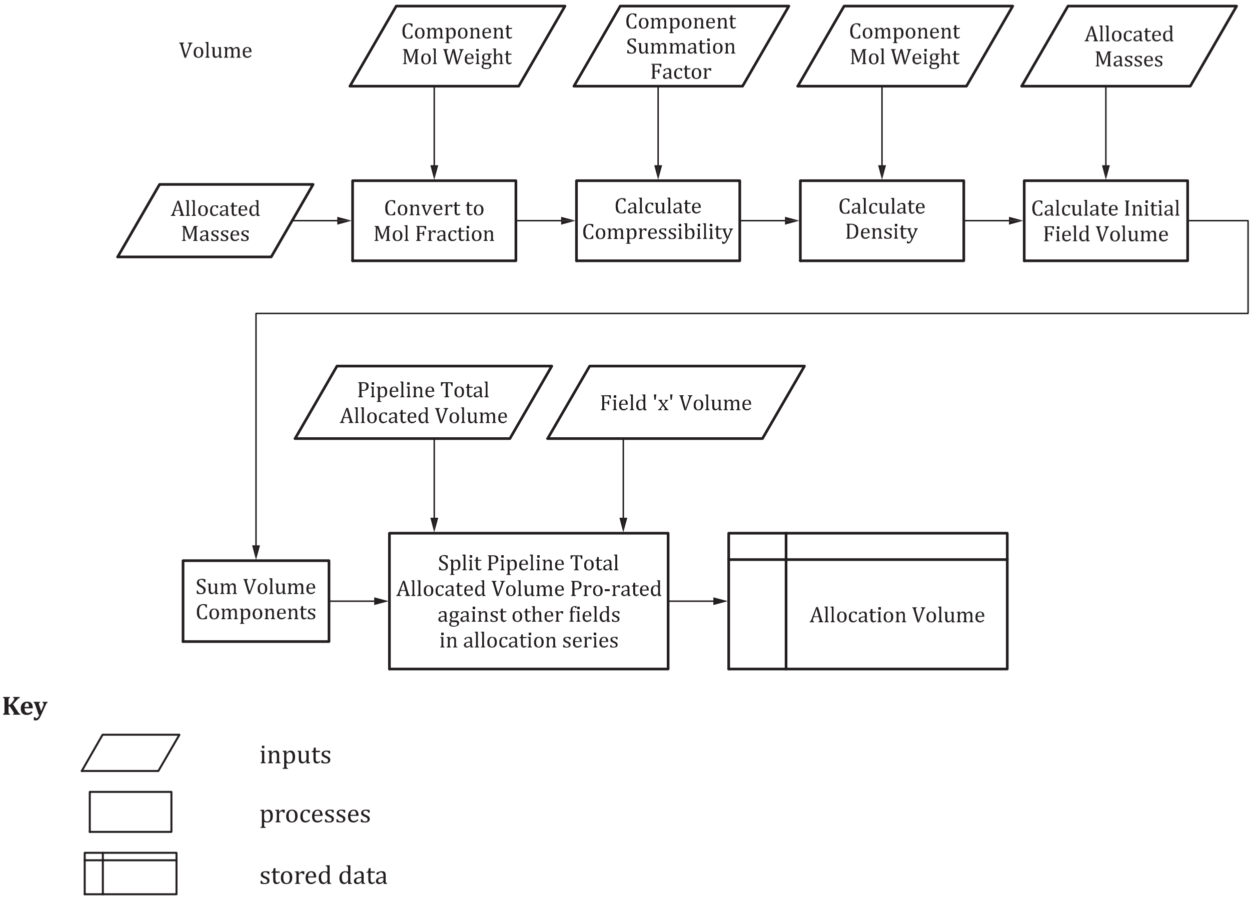


Figure 10 — Volume-allocation process

After the mass component allocation has been performed, the volume flow is calculated using components densities in the following steps:

a) Determine the composition of the allocated stream, expressed as a mole fraction, $X_{f,n}$, using the component relative molecular mass, as given in Formula (5):

$$X_{f,n} = \frac{(A_{\mathrm{MG},f,n} / M_{\mathrm{r},n})}{\sum_{n=1}^{c} (A_{\mathrm{MG},f,n} / M_{\mathrm{r},n})} \tag{5}$$

b) Calculate the component volume, as given in Formula (6):

$$Q_{f,n} = \frac{A_{\mathrm{MG},f,n}}{D_{f,n}} \tag{6}$$

c) Calculate the total volume per field, as given in Formula (7):

$$Q_{\mathrm{TOT},f} = \sum_{n=1}^{c} Q_{f,n} \tag{7}$$

d) Calculate the allocation quantity per field, as given in Formula (8):

$$A_{Q,f} = Q_{TOT} \times \frac{Q_{T,f}}{\sum_{f=1}^{f_{TOT}} Q_{T,f}} \tag{8}$$

where

f_{TOT}	is the total number of inputs nodes;
Q_{TOT}	is the total volume at the export nodal point.

7.9.2 Mass allocation conversion to energy

Generally, the ultimate aim of using a mass-based allocation is to calculate the energy for allocation to a source. After the mass-component allocation has been performed, the energy is calculated as illustrated in Figure 11 using the following steps.

Using factors from standards like ISO 6976, calculate the heating energy per component, as given in Formula (9):

$$U_{f,c} = A_{MG,f,c} \times H_{H,c} \tag{9}$$

where $H_{H,c}$ is the hydrocarbon heating value for each component, c.

1) Calculate the sum of the components for each field, as given in Formula (10):

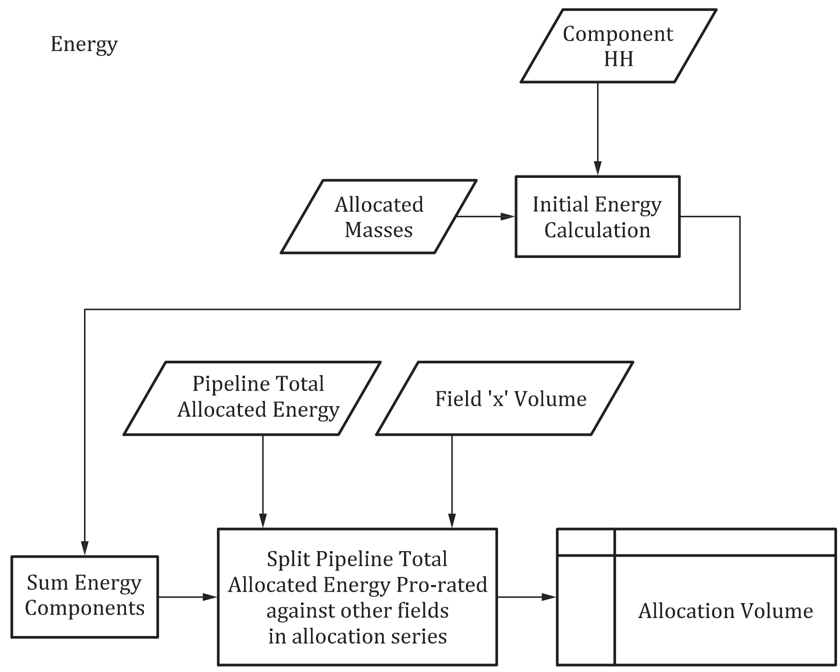
$$U_{T,f} = \sum_{n=1}^{c} U_{f,n} \tag{10}$$

2) Calculate final allocated energy per field, as given in Formula (11):

$$A_{U,f} = U_{TOT} \times \frac{U_{T,f}}{\sum_{f=1}^{f_{TOT}} U_{T,f}} \tag{11}$$

where

f_{TOT}	is the total number of inputs nodes.
U_{TOT}	is the total energy at the export nodal point.



Key

inputs

processes

stored data

Figure 11 — Energy-allocation process

7.10 Quantity allocation

7.10.1 General

Quantity allocation (either in mass, volume or energy) is more simplistic than mass-component allocation. This method may be considered in the following situations:

a) where there are no hydrocarbon liquids for allocation:

Such a system can result from the use of an alternative pipeline system to export the hydrocarbon liquids, separate from the allocation and metering system in question, or it can be assumed and agreed for commercial purposes that there are no hydrocarbon liquids. Agreements should consider how to handle hydrocarbon liquids if they are received.

b) where hydrocarbon liquid quality is agreed for commercial purposes to be consistent across the sources, i.e. produced quantities of liquids are negligible or of similar quality.

The input-metered quantities are prorated to the metered total at the custody transfer exit node, as given in Formula (12):

$$A_{QG,f} = Q \times \frac{Q_{G,f}}{\sum_{f=1}^{f_{TOT}} Q_{G,f}} \tag{12}$$

where

Q	is the quantity of the delivered gas at the custody transfer exit node;
f_{TOT}	is the number of inputs nodes;
$A_{QG,f}$	is the allocated quantity of gas per field;
$Q_{G,f}$	is the quantity of gas for each field.

7.10.2 Mass-quantity allocation

Where the gas is metered in units of mass, it is possible to calculate the volume, moles and energy provided that a representative composition is recorded within the allocation system.

7.10.3 Volume quantity allocation

As volume is used within many older agreements for nominating, targeting and substitution, any new system that is dependent on the older systems can be required to use the same principles. However, as discussed above, mass streams can be readily converted to volume streams by dividing by the density. It is practical, therefore, where it is necessary for a new system to conform to old agreements, to gain the simplicity and flexibility of mass-allocation systems.

The volume quantities are calculated within the flow computers. Final allocation calculations are performed as shown in 7.9.1.

7.10.4 Energy-quantity allocation

As energy is used within many new agreements for nominating, targeting and substitution, many national transmission systems use energy as the unit for trade. In such cases, energy is the preferred method of quantity allocation.

The quantities are calculated within the flow computer. Final allocation calculations are performed as shown in 7.9.2.

7.11 Allocation calculations

7.11.1 General

The formulae shall be suitable for the objective, due to measurement equipment and allocation method chosen. The allocation calculation can be divided into the following steps:

— calculations at the measurement points for the incoming and outgoing streams;

— allocate field's share in the comingled outgoing stream based on allocation method;

— balancing and reconciliation between the in- and outgoing amounts (losses);

— utility gas consumption and allocation (Clause 8);

— all fiscal calculations of gas, oil and water amounts related to fees and tariffs;

— inventory calculations (Clause 9).

7.11.2 Calculations at the measurement points

If the gas is exploited from the ground, there is usual liquid present as oil, condensate or water. The fluid can be separated into liquid and gas phase flows for measurement and sampling or alternatively measured using multiphase measurements as shown in Clause 6. If the hydrocarbon streams after separation are saturated or wet with water, the water content should be subtracted (refer to Peng-Robinson's or Karl Fisher method in ISO 1154) to establish the dry/net hydrocarbon fluid. If another type of contamination is present, these should be defined and subtraction explained (e.g. salt, CO_2, H_2S). The calculation at the ingoing and outgoing measurement points are similar due to the determination of the total/net amount hydrocarbons measured, preferable in mass per component.

Net mass for a field's incoming or outgoing measured liquid (oil/condensate) and gas streams is the gross mass, GrMass, multiplied with one minus the water fraction for the stream.

$$L_{\text{MassF,In}} = L_{\text{GrMassF,In}} \times \left(1 - W_{\text{IOF,In,Wtfrac}}\right)$$

$$G_{\text{MassF,In}} = G_{\text{GrMassF,In}} \times \left(1 - W_{\text{IGF,In,Wtfrac}}\right)$$

The field's incoming measured liquid and gas net mass per component is the mass multiplied with the component fraction from the stream analysis:

$$L_{\text{MassF,In,i}} = L_{\text{MassF,In}} \times L_{\text{CF,In,i,Wtfrac}}$$

$$G_{\text{MassF,In,i}} = G_{\text{MassF,In}} \times G_{\text{CF,In,i,Wtfrac}}$$

The field's incoming total net mass per component is the sum of the measured liquid and gas net mass per component. If lift gas is present in the incoming measured stream, it shall be deducted from the sum, due to under- and over-carry in the first stage separator:

$$T_{\text{MassF,In,i}} = L_{\text{MassF,In,i}} + G_{\text{MassF,In,i}} - G_{\text{MassF,LG,i}}$$

A field's total well production is the incoming total mass including the field's specific flare eventually released before the incoming gas measurement. The field's total produced net mass:

$$T_{\text{MassF,WP}} = \sum_{i=N2}^{i=n} T_{\text{MassF,In,i}} + \sum_{i=N2}^{i=n} T_{\text{MassF,Fls,i}}$$

Well production is not the same per definition as the processed gas and oil coming out of the process facilities.

For a facility's outgoing streams, the variable is indexed with F= Fa (facility) and S= all the outgoing streams (export, injection, flare, fuel, vented and support). For fully processed gas, the water-in-gas weight fraction is normally set to 0. Some flare gas streams can have relatively high-water content. All the outgoing streams are not measured nor sampled, but if the stream does not contribute a significant amount in the allocation, an approximation of the composition can be accepted. The composition of flare and vented gas is often set equal to the fuel or export gas composition.

Outgoing streams refers to any of the following streams:

Export oil net mass:	$L_{\text{MassFa,Exp}} = L_{\text{GrMassFa,Exp}} \times \left(1 - W_{\text{IOFa,Exp,Wtfrac}}\right)$
Export oil component mass:	$L_{\text{MassFa,Exp,i}} = L_{\text{MassFa,Exp}} \times L_{\text{CFa,Exp,i,Wtfrac}}$
Export oil net mass:	$L_{\text{MassFa,Exp}} = \sum_{F=1}^{F=n} L_{\text{MassF,Exp}}$
Export/Out gas net mass:	$G_{\text{MassFa,Out}} = G_{\text{GrMassFa,Out}} \times \left(1 - W_{\text{IGFa,Out,Wtfrac}}\right)$
Export gas component mass:	$G_{\text{MassFa,Exp,i}} = G_{\text{MassFa,Exp}} \times G_{\text{CFa,Exp,i,Wtfrac}}$
Flare gas component mass:	$G_{\text{MassFa,Fl,i}} = G_{\text{MassFa,Fl}} \times G_{\text{CFa,Fl,i,Wtfrac}}$

Fuel gas component mass: $G_{\text{MassFa,Fu,i}} = G_{\text{MassFa,Fu}} \times G_{\text{CFa,Fu,i,Wtfrac}}$

Vented gas component mass: $G_{\text{MassFa,V,i}} = G_{\text{MassFa,V}} \times G_{\text{CFa,V,i,Wtfrac}}$

Injection gas comp. mass: $G_{\text{MassFa,Inj,i}} = G_{\text{MassFa,Inj}} \times G_{\text{CFa,Inj,iWtfrac}}$

Support gas comp. mass: $G_{\text{MassFa,Su,i}} = G_{\text{MassFa,Su}} \times G_{\text{CFa,Su,iWtfrac}}$

where

$L_{\text{MassF, In}}$	is the liquid net mass in a field's incoming stream;
$L_{\text{GrMassF, in}}$	is the liquid gross mass in a field's incoming stream;
$W_{\text{IOF,In,Wtfrac}}$	is the water weight fraction in the liquid stream;
$G_{\text{MassF, In}}$	is the gas net mass in a field's incoming stream;
$G_{\text{GrMassF, in}}$	is the gas gross mass in a field's incoming stream;
$W_{\text{IGF,In,Wtfrac}}$	is the water weight fraction in the gas stream;
$L_{\text{MassF, In, i}}$	is the liquid net mass for a given component i, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{7+} or higher for liquid);
$G_{\text{MassF, In, i}}$	is the gas net mass for a given component i, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{6+} for dry lean gas, but can be higher for rich gas);
$C_{\text{Fa, Exp, iWtfrac}}$	is the component weight fractions from the stream analysis, where i is an index for a given component;
$T_{\text{MassF, In, i}}$	is the total net mass per component i.

If the facility flare, fuel or vented gas is measured or estimated in volume, the volume can be converted to mass by multiplying the volume by the gas density given in the gas analysis report.

Gas density can also be calculated by using ISO 6976 or convert the volume to kmol by dividing the volume with the ideal gas constant and multiplying with the molecular weight.

$$G_{\text{MassFa,Out}} = G_{\text{VolFa,Out}} \times G\rho_{\text{Fa,Out}}$$

or

$$G_{\text{MassFa,Out}} = \left(\frac{G_{\text{VolFa,Out}} * G_{\text{MWFa,Out}}}{\text{GK}} \right)$$

where

$G_{\text{MassFa, out}}$	is the gas net mass for a facility outgoing stream;
$G_{\text{VolFa, out}}$	is the gas net volume in a facility outgoing stream;
$\rho_{\text{Fa,Out}}$	is the density representative for the gas volume (determined either in laboratory or calculated from ISO 6976);
$G_{\text{MWFa,Out}}$	is the molecular weight representative for the gas;
GK	is the gas constant 23,644 8 Sm3/kmol.

The calculated outgoing processed oil is the same as the export and produced oil, while processed gas is allocated further to give the fields flare, fuel, vented, lift, injected and export gas. Processed gas is an outgoing stream in the utility and export/sales gas calculations.

7.11.3 Allocated field's share

Dependent on the allocation method chosen, the accompanying formulae can be used.

7.11.3.1 Pro-rata calculation for oil and gas

If the incoming measurements have similar measurement uncertainty and there is a system balance, the outgoing share is proportional to the field's incoming share.

This is one of several possible pro-rata methods (pro-rata based on total hydrocarbon per component).

For example, another approach is to use the oil recovery factor to split hydrocarbon production into oil and gas, and thereafter pro-rata allocation by component separately for oil and gas.

Outgoing produced oil is the same as export oil, while processed gas is allocated further to give the fields flare, fuel, vented, lift, injection and export gas.

Incoming share per component i:

$$M_{\text{KF,P,i}} = \left(\frac{T_{\text{MassF,P,i}}}{\sum_{F=1}^{F=n} T_{\text{MassF,P,i}}} \right)$$

Export oil: $L_{\text{MassF,Exp,i}} = M_{\text{KF,P,i}} * L_{\text{MassFa,Exp,i}}$

Processed gas: $G_{\text{MassF,P,i}} = T_{\text{MassF,In,i}} - L_{\text{MassF,Exp,i}})$

The above formula is only true for allocated processed gas if total HC mass imbalance = 0.

Otherwise, allocated processed gas should by calculated by pro-rata share of total processed gas based on total HC per component, similar to allocation of oil export.

Well production gas: $G_{\text{MassF,WP,i}} = G_{\text{MassF,iP,i}} + G_{\text{MassF,Fls,i}}$

Well production oil: $L_{\text{MassF,WP,i}} = L_{\text{MassF,Exp,i}}$

where

$L_{\text{MassF, P, i}}$	is the liquid net mass for a field processed/production stream for component i, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{7+} or higher for liquid);
$T_{\text{MassF, In, i}}$	is the total net mass for a field incoming stream per component i;
$L_{\text{MassFa, Out, i}}$	is the liquid net mass for a facility outgoing/export stream per component i;
$L_{\text{MassF, Exp, i}}$	is the allocated liquid net mass for a field export stream per component i;
$G_{\text{MassF, P, i}}$	is the allocated gas net mass for a field processed stream for component i, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{6+} for dry lean gas, but can be higher for rich gas).

7.11.3.2 By difference allocation by simulation

If the non-measured stream is more than 70 % of the incoming production, or capital return on investment of a metering station is not justified related to possible loss, the field's outgoing share is determined by recovery factors and the "by-difference" calculation.

Determination using the "by-difference" method can be executed in at least three ways.

a) Simulation of gas recovery factors for the measured fields gas export calculation directly.

$$G_{\mathrm{MassF,Exp,i}} = G_{\mathrm{RFF,Exp,i}} * T_{\mathrm{MassF,In,i}}$$

Determination of the one field without measurement (often the host)

$$G_{\mathrm{MassH,Exp,i}} = G_{\mathrm{MassFa,Exp,i}} - \sum_{F=1}^{F=n} G_{\mathrm{MassF,Exp.i}}$$

where

$G_{\mathrm{MassF,\,Exp,\,i}}$ is the gas net mass for a field export stream for component i, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{6+} for dry lean gas, but can be higher for rich gas);

$G_{\mathrm{RFF,Exp,i}}$ is the from simulation; gas recovery factor for field F, stream export, component i;

$T_{\mathrm{MassF,\,In,\,i}}$ is the total net mass for a field incoming stream per component i.

b) Simulation of oil recovery factors for the oil export and calculation of the gas production and gas export.

1) Liquid export:

$$L_{\mathrm{MassF,Exp,i}} = O_{\mathrm{RFF,Exp,i}} * T_{\mathrm{MassF,In,i}}$$

2) Gas recovery factor:

$$G_{\mathrm{RFF,P,i}} = 1 - O_{\mathrm{RFF,Exp,i}}$$

3) Gas processed:

$$G_{\mathrm{MassF,P,i}} = G_{\mathrm{RFF,P,i}} * T_{\mathrm{MassF,In,i}}$$

4) Gas export:

$$G_{\mathrm{MassF,Exp,i}} = G_{\mathrm{MassF,P,i}} - G_{\mathrm{MassF,F\&F,i}} - G_{\mathrm{MassF,V,i}} - G_{\mathrm{MassF,Inj,i}}$$

5) Determination of the one field without measurement (often the Host)

$$G_{\mathrm{MassH,Exp,i}} = G_{\mathrm{MassFa,Exp,i}} - \sum_{F=1}^{F=n} G_{\mathrm{MassF,Exp.i}}$$

where

$L_{\mathrm{MassF,\,Exp,\,i}}$ is the liquid net mass for a field F, stream export gas, component i, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{7+} for liquid);

$O_{\mathrm{RFF,Exp,i}}$ is the oil recovery factor for field F, stream Exp, component I;

$T_{\mathrm{MassF,\,In,\,i}}$ is the total net mass for a field incoming stream per component i;

$L_{\mathrm{MassF,\,P,\,i}}$ is the liquid net mass for a field F, stream P, component I;

$G_{\mathrm{RFF,P,i}}$ is the gas recovery factor for field F, stream P, component I;

$G_{\mathrm{MassF,\,Exp,\,i}}$ is the gas net mass for a field F, stream exp, per component i, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{6+} for dry gas or higher for rich gas);

$G_{\mathrm{MassF,\,P,\,i}}$ is the gas net mass for a field F, stream P, per component;

$G_{\text{MassF, FandF, i}}$ is the gas net mass for a field F, stream F and F, per component i;

$G_{\text{MassF, V, i}}$ is the gas net mass for a field F, stream vented, per component i, (if any);

$G_{\text{MassF, Inj, i}}$ is the gas net mass for a field F, stream injection, per component i, (if any).

c) By difference allocation by calculation

Calculation of export gas and oil fractions and the field's share of export streams.

The formulae below are field allocation by pro-rata per component ratio between HC measured and export streams (also called "component ratio method"). Then the by-difference field gets the difference.

If there are vented gas and injection gas at the facility, these streams shall be included in the total outgoing streams in addition to the flare and fuel streams for allocation.

Gas export fraction:

$$G_{KFa,Exp,i} = \frac{G_{\text{MassFa,Exp,i}}}{\left(G_{\text{MassFa,Exp,i}} + L_{\text{MassFa,Exp,i}} + G_{\text{MassFa,Fla+Fua,i}} + G_{\text{MassF,Fls+Fus,i}}\right)}$$

1) Liquid export fraction:

$$L_{KFa,Exp,i} = \frac{L_{\text{MassFa,Exp,i}}}{\left(G_{\text{MassFa,Exp,i}} + L_{\text{MassFa,Exp,i}} + G_{\text{MassFa,Fla+Fua,i}} + G_{\text{MassF,Fls+Fus,i}}\right)}$$

2) Field export gas mass:

$$G_{\text{MassF,Exp,i}} = G_{\text{KFa,Exp,i}} * T_{\text{MassF,In,i}}$$

3) Field export liquid mass:

$$L_{\text{MassF,Exp,i}} = L_{\text{KFa,Exp,i}} * T_{\text{MassF,In,i}}$$

4) Field "by difference" mass:

$$G_{\text{MassH,Exp,i}} = G_{\text{MassFa,Exp,i}} - \sum_{F=1}^{F=n} G_{\text{MassF,Exp.i}}$$

5) Field "by difference" mass:

$$L_{\text{MassFd,Exp,i}} = L_{\text{MassFa,Exp,i}} - \sum_{F=1}^{F=n} l_{\text{MassF,Exp.i}}$$

where

$G_{\text{KFa,Exp,i}}$ is the gas fraction for the facility, gas export and component i, where I is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{6+} for dry gas or higher for rich gas);

$L_{\text{KFa,Exp,i}}$ is the liquid fraction for the facility, oil export and component I, where i is an index for the components N_2, CO_2 and C_1 up to C_n (n is usually C_{7+} for oil);

$G_{\text{MassFa, Exp, i}}$ is the gas net mass for a facility, stream exp, per component I;

$L_{\text{MassFa, Exp, i}}$ is the liquid net mass for a facility, stream exp, component I;

$G_{\text{MassF, Exp, i}}$ is the gas net mass for a field F, stream export, per component i;

$T_{\text{MassF, In, i}}$ is the total net mass for a field F, stream in, per component i.

$L_{\text{Mass,H, Exp, i}}$ is the liquid net mass for a field F by difference, stream exp, per component i.

7.11.3.3 By difference method

In this method, one of the fields is without incoming production measurement. This is typically the field with the highest production, which is usually the host. The other field(s)'s allocated production is determined by flash simulation or calculation. The un-measured field's amount is the difference between the outgoing total measured amount and the sum of the calculated tie-in fields allocated amounts. The allocation uncertainty of the field without measurement is a result based on the absolute uncertainty and losses for the other fields (1 to n).

The allocated total mass:

$$M_{\text{Massinout}} = \kappa_{\text{iGRFn}} * M_{\text{Massinin}}$$

$$M_{\text{MassiXout}} = M_{\text{MassiExpout}} - \sum_{n=1}^{n=n} M_{\text{Massinout}}$$

$$T_{\text{MassXout}} = \sum_{i=N2}^{i=C6+} M_{\text{MassiXout}}$$

In the by-difference method, simulation is used to establish recovery, separation and flash factors (κ_{iGRFA}) based on measurements of flow, pressure and temperature, including component combination. This calculation can be done by an integrated or by a standalone simulation program using specific PVT software or a process simulator. These calculations also require selection of an appropriate equation of state and the flashing conditions simulating a single flash or a multistage flash. The allocation method can also establish recovery, separation and flash factors by calculation based on the assumption that flare and fuel have equal component composition and the asset or hub has adequate mass balance.

If lift gas is used in the application, the lift gas shall be included in the flash calculation to give the correct equilibrium in the separator for the flash calculations. The parties shall also agree on how to perform the flash simulation, either each field alone or all tie-in fields comingled.

Allocation by difference usually arises when an existing gas or condensate production and transportation system is extended by allowing access to the production from new fields.

7.12 Allocation methodology selection

The main method of allocation calculation is pro-rata allocation. In some applications, allocation is carried out by difference or by use of simulation or flash calculations.

The methods can be performed in energy, mass or volume. Allocation based on energy or mass by hydrocarbon components are the most comprehensive. If allocation by volume is used for well back allocation for reservoir monitoring purposes, it is generally not recommended for fiscal allocation but can be accepted when allocation by mass is not possible or the products or energy has minimal affiliation. An example is utility gas allocation, where mass measurement nor representative sampling of the flare is possible. If the flare gas is a small share of the utility gas consumption, it can be assumed that the flare gas composition is equal to fuel gas composition or use an agreed density to convert volume to mass.

The most comprehensive allocation method for gas is pro-rata based on energy and is recommended in applications where several fields, huge gas amounts and values are to be allocated. By-difference may be used in applications where few fields, less amounts and values are involved, mainly if the non-measured field holds more than 70 % of the total production.

7.13 Balancing and reconciliation calculations

7.13.1 General

Mass balance and reconciliation are the foundation principles for allocation.

The theoretical principle for allocation is that the amount of mass going in shall be the same amount of mass coming out of a common process or transportation system. In practice, there is always a difference between the ingoing and outgoing measured amounts. This can be due to:

— measurement uncertainty;

— time lag in measurements (some pipelines have delays of days between input and output);

— temperature and/or pressure change to constrained volume;

— change in volume due to mixing, condensation or flashing;

— vented gas or other outgoing streams not measured or sampled;

— difference in quality (GCV, H_2S etc.) due to mixing.

The difference between the ingoing and outgoing measurement points can have a significant impact on the allocated amounts. The differences must be accounted for. The difference, ΔG_{NMass} is the sum of differences, which are often referred to as “losses”, “inventory”, “storage”, “line packing”, “build up buffer”, “line fill” etc.

If the difference is accounted for, it is usually calculated in mass then converted to volume or energy. Estimated volumes are converted to standard condition (15 °C at 1 atm. pressure and/or 40 MJ). Balance in volume can lead to divergence over time. Mass in kg needs no conversion.

If the gas is transported through several pipelines with different volumes and mixed in several steps to the sales point, the “loss” is allocated in each step related to the different pipeline’s construction volumes and fluid share.

$$\sum_{M=1}^{M=n} G_{\text{NMassinM}} = \sum_{M=1}^{M=n} G_{\text{NMassoutM}} + \Delta G_{\text{NMass}}$$

$$\Delta G_{\text{NMass}} = \sum_{M=1}^{M=n} G_{\text{NMassinM}} - \sum_{M=1}^{M=n} G_{\text{NMassoutM}}$$

Mass balance and reconciliation are the foundation principles for allocation as per 7.4. The challenge is to adjust the difference between the incoming and outgoing amount in a fair manner between the fields:

$$\Delta G_{\text{NMassFa,out}} = \sum_{n=1}^{n=x} G_{\text{NMassnin}} - G_{\text{NMassFa,out}}$$

7.13.2 Reconciliation

Reconciliation can be performed using pro-rata or statistical methods as per 13.6.5. Reconciliation can also be based on the measurement uncertainty as per 7.7.

$$\Delta G_{\text{NMassF,out}} = \beta_{\text{F}} * I$$

$$I = G_{\text{NMassFa,out}} - \sum_{F=1}^{F=n} G_{\text{NMassF,in}}$$

$$\beta_{\text{F}} = \frac{U_{F,in}^2}{\sum_{F=1}^{F=x} U_{F,in}^2}$$

where

$G_{\text{NMass n out}}$	is the gas net mass for field n, outgoing stream;
$G_{\text{NMassn in}}$	is the gas net mass for field n, incoming stream;
$\Delta G_{\text{NMassnout}}$	is the imbalance allocated to field n;
I_{B}	is the total imbalance between the incoming and outgoing masses;
β_{F}	is the ratio of uncertainties for field F;
U_{F}	is the absolute uncertainty of measurement for field F.

7.13.3 Balancing and reconciliation accounts

If the differences are related to time, volume or mixing, the allocation procedure shall describe in detail how the differences are handled, shared and accounted for between the fields or shippers.

8 Utility and disposed gas allocation

8.1 General

A field's produced gas shall cover the field's demand for utility gas, as flare, fuel, lift and vented gas needed for processing and transportation of the hydrocarbons aimed for sale or injection. If not, the field shall purchase support gas for the purposive usage. Injection gas is not included in the utility gas since injected gas can be subjected to purchase or sale if the facility has no gas export.

Utility gas usage at a facility is divided into two categories, field specific and common usage as per Figure 12. Field specific utility gas or attributable gas is utility gas usage solely for a specific field, such as extra flaring during a curtailment, usage of extra fuel for special equipment (e.g. pumps), or support gas to a field that does not produce adequate gas for utility purposes (e.g. late life lift gas).

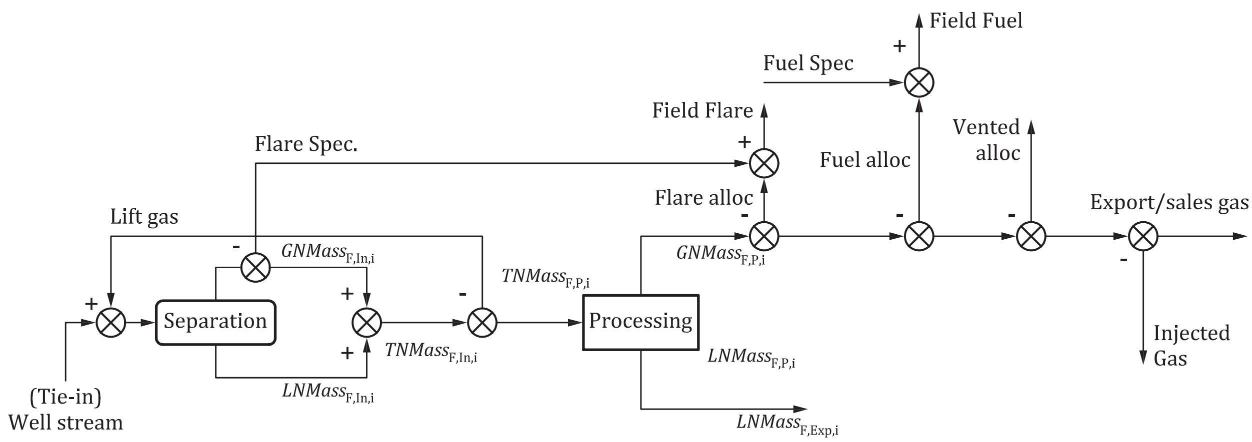


Figure 12 — Utility and disposed gas data diagram

The field's specific flare gas amount is estimated for each incident. The flare gas density is used to convert between volume and mass. The flare composition and the density can be defined equal to fuel or export gas since representative sampling of the flare is not possible. If the field specific flare is a major part of the utility gas, it should be considered to use the field's incoming measured gas density and composition.

Environmental fees are allocated based on the field's allocated flare-, fuel-, vented gas numbers.

To calculate the field specific flare, use Formula (13):

$$G_{\text{MassF,Fls,}} = G_{\text{VolF,Fls}} * G\rho_{\text{F,Fl}} \tag{13}$$

The facility common flare for allocation is the measured flare minus the sum of field(s) specific flare amounts.

To calculate the facility flare for allocation, use Formula (14):

$$G_{\text{MassFa,Fla}} = G_{\text{MassFa,Fl}} - \sum_{F=1}^{F=n} G_{\text{MassF,Fls}} \tag{14}$$

Allocation of flare and fuel can be done pro-rata based on incoming or produced mass in kg or volume in oil equivalent (OE).

Each field share is the field's total incoming mass divided by the sum of all the incoming total mass.

To calculate the incoming production mass fraction, use Formula (15):

$$M_{\text{KF,In}} = \frac{T_{\text{NMassF,P}}}{\sum_{F=1}^{F=n} T_{\text{MassF,P}}} \tag{15}$$

To calculate the flare allocated share, use Formula (16):

$$G_{\text{MassF,Fla}} = M_{\text{KF,In}} * G_{\text{MassFa,Fla}} \tag{16}$$

To calculate the field flare, use Formula (17):

$$G_{\text{MassF,Fl}} = G_{\text{MassF,Fls}} + G_{\text{MassF,Fla}} \tag{17}$$

Specific fuel gas is extra fuel usage due to a specific equipment for a field solely. The field's specific fuel gas mass is the estimated or calculated specific fuel volume multiplied by the fuel gas density.

To calculate the fuel specific, use Formula (18):

$$G_{\text{MassF,Fus}} = G_{\text{VolF,Fus}} * G\rho_{\text{Fa,Fu}} \tag{18}$$

The facility common fuel for allocation is the measured fuel minus the sum of field specific fuel amount.

To calculate the facility fuel for allocation, use Formula (19):

$$GM_{\text{MassFa,Fua}} = GM_{\text{MassFa,Fu}} - \sum_{F=1}^{F=n} G_{\text{MassF,Fus}} \tag{19}$$

To calculate the fuel allocated, use Formula (20):

$$G_{\text{MassF,Fua}} = M_{\text{KF,In}} * G_{\text{MassFa,Fua}} \tag{20}$$

To calculate the field fuel, use Formula (21):

$$G_{\text{MassF,Fu}} = G_{\text{MassF,Fus}} + G_{\text{MassF,Fua}} \tag{21}$$

To calculate the field total flare and fuel, use Formula (22):

$$G_{\text{MassF,FandF}} = G_{\text{MassF,Fl}} + G_{\text{MassF,Fu}} \tag{22}$$

Vented gas is gas discharged directly (not burned) to the air due to discharge from equipment, valves, tanks, leaks continuously or by events. The vented gas is usually not measured but estimated. The vented gas is a small share of the utility gas and is normally neglected. If it is appendant with an environmental fee, the fee shall be shared. The gas composition can be defined equal to a suitable gas stream, e.g. fuel, lift or export gas.

To calculate the vented gas, use Formula (23):

$$G_{\text{MassF,V}} = G_{\text{MassFa,V}} * M_{\text{KF,In}} \tag{23}$$

Lift gas is gas used for well support to lift the liquid out of the well and is specific for a well and field. The field lift gas is either measured at each well or measured as a total for the field. If the lift gas is subtracted from the total hydrocarbon incoming stream, it should not be subtracted twice.

To calculate the lift gas, use Formula (24):

$$G_{\text{MassF,LG,i}} = G_{\text{MassF,LG}} * C_{\text{F,LG,i}} \tag{24}$$

Support gas is also specific gas either added or subtracted from a field.

To calculate the support gas, use Formula (25):

$$G_{\text{MassF,Sus}} = G_{\text{VolF,Sus}} * G\rho_{\text{Fa,Sus}} \tag{25}$$

A field's utility gas mass is the sum of the above streams:

$$G_{\text{MassF,Util}} = G_{\text{MassF,FandF}} + G_{\text{MassF,V}} + G_{\text{MassF,LG}} + G_{\text{MassF,Sus}}$$

Lift gas shall not be included, since lift gas is already deducted prior to determine field gas production in 7.11.1.

To calculate the export/sales gas, use Formula (26):

$$G_{\text{MassF,Exp}} = G_{\text{MassF,P}} - G_{\text{MassF,FandF}} - G_{\text{MassF,V}} - G_{\text{MassF,IG}} \tag{26}$$

where

$G_{\text{MassF, Exp}}$	is the field export gas mass;
$G_{\text{MassF, P}}$	is the field produced gas mass;
$G_{\text{MassF, FandF}}$	is the sum of field flare and fuel gas masses;
$G_{\text{MassF, V}}$	is the field vented gas mass;
$G_{\text{MassF, IG}}$	is the field injected gas mass.

If the field's gas aimed for sale is negative (mainly related to specific flaring or heavy lift gas usage at late life), utility gas must be supported from another field or host. The export gas is set to zero and the negative gas amount is considered as support gas from the another (host) field.

The support gas shall be deducted to give the supporting field's gas aimed for sale.

The masses can be converted to volumes using densities or the gas law.

The amounts can be multiplied with discharge factors or fees to allocated discharges to air.

8.2 Utility gas allocation by volume

The definition of the streams is the same as in Clause 8. Below are the equations for volume allocation.

Facility specific flare gas: $G_{\text{VolFa,Fls}} = \sum_{F=1}^{F=n} G_{\text{VolF,Fls}}$

Facility specific fuel gas: $G_{\text{VolFa,Fus}} = \sum_{F=1}^{F=n} G_{\text{VolF,Fus}}$

Facility flare for allocation: $G_{\text{VolFa,Fla}} = G_{\text{VolFa,Fl}} - G_{\text{VolFa,Fls}}$

Facility fuel for allocation: $G_{\text{VolFa,Fua}} = G_{\text{VolFa,Fu}} - G_{\text{VolFa,Fus}}$

where

$G_{\text{VolFa, Fls}}$ is the facility specific flare gas volume;

$G_{\text{VolF, Fls}}$ is the field specific flare gas volume;

$G_{\text{VolFa, Fus}}$ is the facility specific fuel gas volume;

$G_{\text{VolF, Fus}}$ is the field specific fuel Gas volume;

$G_{\text{VolFa, Fla}}$ is the facility allocated flare gas volume;

$G_{\text{VolFa, Fl}}$ is the facility measured flare gas volume;

$G_{\text{VolFa, Fua}}$ is the facility allocated fuel gas volume;

$G_{\text{VolFa, Fu}}$ is the facility measured fuel gas volume.

The facility fuel and flare gas for allocation are allocated between the fields based on pro-rata production in OE. (1 Sm^3 oil or 1 000 Sm^3 gas with gross calorific of 40 MJ/Sm^3 = 1 OE).

Incoming production volume factors:

$$V_{\text{KF,In}} = \frac{V_{\text{VolOEF,P}}}{\sum_{F=1}^{F=n} V_{\text{VolOEF,P}}}$$

where

$V_{\text{KF, In}}$ is the volume factor for incoming production;

$V_{\text{ol OEF, P}}$ is the field incoming production in OE or BOE.

Gas for allocation multiplied with the production factor gives the allocated amount.

Allocated flare gas: $G_{\text{VolF,Fla}} = G_{\text{VolFa,Fla}} * V_{\text{KF,In}}$

Allocated fuel gas: $G_{\text{VolF,Fua}} = G_{\text{VolFa,Fua}} * V_{\text{KF,In}}$

Allocated vented gas: $G_{\text{VolF,Va}} = G_{\text{VolFa,V}} * V_{\text{KF,In}}$

where

$G_{\text{VolF, Fua}}$ is the field allocated fuel gas volume;

$G_{\text{VolFa, Fua}}$ is the facility measured fuel gas volume;

$G_{\text{VolF, Fla}}$ is the field allocated flare gas volume;

$G_{\text{VolFa, Fla}}$ is the facility allocated flare gas volume;

$G_{\text{VolF, Va}}$ is the field measured vented gas volume;

$G_{\text{VolFa, V}}$ is the facility specific vented gas volume.

Each field flare and fuel are the sum of allocated and specific share.

Field flare: $G_{\text{VolF,Fl}} = G_{\text{VolF,Fla}} + G_{\text{VolF,Fls}}$

Field fuel: $G_{\text{VolF,Fu}} = G_{\text{VolF,Fua}} + G_{\text{VolF,Fus}}$

where

$G_{\text{VolF, Fl}}$ is the field flare gas volume;

$G_{\text{VolF, Fu}}$ is the field fuel gas volume.

Field utility gas usage is the sum of fuel, flare, vented, lift and support gas.

Field utility gas: $G_{\text{VolF,UG}} = GV_{\text{VolF,FandF}} + G_{\text{VolF,V}} + G_{\text{VolF,LG}} + G_{\text{VolF,Su}}$

Lift gas shall be deducted since lift gas is already deducted prior to determine field gas production in 11.2.

Export/sales gas:

$$G_{\text{VolF,Exp}} = G_{\text{VolF,P}} - G_{\text{VolF,FandF}} - G_{\text{VolF,V}} - G_{\text{TVolF,IG}}$$

where

$G_{\text{TVolF, Exp}}$ is the field export gas volume;

$G_{\text{VolF, P}}$ is the field produced gas volume;

$G_{\text{TVolF, FandF}}$ is the sum of field flare and fuel gas volumes;

$G_{\text{VolF, V}}$ is the field vended gas volume;

$G_{\text{VolF, IG}}$ is the field injected gas volume.

If the field's gas aimed for sale is negative (mainly related to specific flaring or heavy lift gas usage at late life), utility gas must be supported from another field or host. The export gas is set to zero and the negative gas amount shall be directed as support gas from the another (host) field.

The support gas shall be deducted to give the supporting field's gas aimed for sale.

Environmental fees are allocated based on the field's allocated flare, fuel, vented gas amounts.

The amounts can be multiplied with discharge factors or fees to allocated discharges to air.

8.3 Injection and sales (purchase) gas allocation

Injected gas is gas used for reservoir support to increase the reservoir pressure to "push" the hydrocarbons out of the wells. The field injection gas is either measured at each well or measured as a total for the field. The injection gas may be sampled, and the gas analysed, but can also be defined as equal to the fuel or export gas.

Injection gas components: $G_{\text{MassFa,Inj,i}} = G_{\text{MassFa,Inj}} * C_{\text{F,Inj,i}}$

Since injected gas may be subjected to sale, the allocation should be conducted on component level. Based on pro-rata from the incoming streams, the allocation mass fraction should apply on a component level.

Allocation mass component fraction: $$M_{\mathrm{KF,in,i}} = \frac{T_{\mathrm{MassF,In,i}}}{\sum_{F=1}^{F=n} T_{\mathrm{MassF,In,i}}}$$

Field allocated injection gas can also mean sales gas for some field’s share and purchase gas for the host in addition to the injection gas contribution.

Field allocated injection gas: $$G_{\mathrm{MassF,Inj,i}} = G_{\mathrm{MassFa,Inj}} * K_{\mathrm{F,In,i}}$$

Field sales gas mass: $$G_{\mathrm{MassF,Sale,}} = \sum_{i=C1}^{i=Cn} G_{\mathrm{MassF,Inj,i}}$$

The field sales gas volume can be determined based on the calculated density outlined in ISO 6976.

Field sales gas volume: $$G_{\mathrm{VolF,Sale}} = G_{\mathrm{MassF,Sale}} * G\rho_{\mathrm{F,Sale}}$$

where $K_{\mathrm{F,In,i}}$ = each field's mass fraction of gas

8.4 Export gas and oil mass and volume

Export gas is gas aimed for sale.

Export gas components: $$G_{\mathrm{MassFa,Exp,i}} = G_{\mathrm{MassFa,Exp}} * C_{\mathrm{F,Exp,i}}$$

Field export gas: $$G_{\mathrm{MassF,Exp,i}} = G_{\mathrm{MassFa,exp,i}} * K_{\mathrm{F,in,i}}$$

The field export gas’s GCV, Wobbe index, density can be determined by the ISO 6976 calculations.

If the field gas aimed for sale is negative (mainly related to specific flaring or heavy lift gas usage at late life), the utility gas shall be supported from another field or host. The export gas is set to zero and the negative gas amount to be directed as support gas from the host field and included as field specific gas before calculation of facility gas for allocation.

A field’s total allocated outgoing mass is the sum of the calculated component masses.

$$M_{\mathrm{MassF,S}} = \sum_{i=N2}^{i=n} M_{\mathrm{MassF,S,i}}$$

where

$M_{\mathrm{MassF,S,}}$ is the Mass for Field F, Stream S;

$M_{\mathrm{MassF,S,i}}$ is the Mass for Field F, Stream S and component i.

The utility gas is usually deducted from the produced or processed gas to give the gas amount aimed for sale and/or injection unless the utility gas is imported from another field. If the utility gas is imported, differences in component composition and GCV should be considered. The utility gas usage is often encumbered with special contractual agreements, but it is possible to allocate the utility gas usage on equal terms by dividing the utility gas usage into specific utility gas usage and allocated utility gas usage.

9 Inventory

During start-up, the empty facility or pipeline is filled with gas before any outgoing gas is measured. The gas amount is considered as “constrained” and is often referred to as “filling”,” line-fill”, “inventory” or “dead stock”. The amount can be added when the facility or pipeline is emptied. This can be repeated either in full or in part during shutdowns or maintenance.

During operation, more can be added to the facility or pipeline by increasing the pressure. This extra amount is often referred to as “capacity buffer” or “line packing”.

If the allocation period is quite long, the inventory represents only a negligible quantity relative to the total mass shipped during the allocation period.

If the allocation period is short, there can be a difference due to obstruction or curtailment at the individual fields. The quality of the blend delivered can be significantly different and consequently the normal production yields no longer correspond.

Each field’s inventory is recalculated at the end of every allocation period to give the closing stock. The inventory imbalance between the beginning and the end of the allocation period is the difference between the closing stock of the current period and the closing stock of the previous period. This imbalance is calculated in terms of quantity and quality for each field to give the inventory volume/mass ownership.

If a field is connected to a gas transportation network at an entry point length different from the other fields and its production is transported only through part of the gas pipeline, the part of the inventory upstream of this entry point shall be differentiated from the downstream part. The gas inventory masses in each of the pipeline sections are calculated as before. Care is to be taken that the calculations include only the fields that contribute to the calculated inventory. For a subsea connection, the pressure at this point can be calculated using the conventional pressure-loss formula for pipelines. The total inventory of the fields furthest upstream in this transportation system is the sum of the inventories of these fields calculated in the two or more sections of the gas pipeline.

Inventory calculation can also be the enclosed volume calculated at different pressures which is added or subtracted under the given circumstances.

The difference, ΔG_{NMass} is the sum of differences, which are often referred to as “losses”, “inventory”, “storage”, “line packing”, “build up buffer”, “line fill” etc.

If the difference is accounted for, it is usually calculated in mass then converted to volume or energy. Estimated volumes are converted to standard condition (15 °C at 1 atm. pressure and/or 40 MJ). Balance in volume can lead to divergence over time. Mass in kg needs no conversion.

If the gas is transported through several pipelines with different volumes and mixed in several steps to the sales point, “loss” shall be allocated in each step related to the different pipeline’s construction volumes and fluid share.

$$\sum_{M=1}^{M=n} G_{\text{NMassinM}} = \sum_{M=1}^{M=n} G_{\text{NMassoutM}} + \Delta G_{\text{NMass}}$$

$$\Delta G_{\text{NMass}} = \sum_{M=1}^{M=n} G_{\text{NMassinM}} - \sum_{M=1}^{M=n} G_{\text{NMassoutM}}$$

10 Allocation cases and typical lay out

10.1 Allocation cases

10.1.1 General

When dealing with gas and associated products, a variety of allocation cases are possible, as illustrated in Table 11.

Table 11 — Allocation cases

Allocation types	Inputs	Outputs or products
Topside wells	Well estimation based on tests	Installation productions
Subsea wells	Well meters on each well	Surface measurements
Processing complex	Inputs measurement: installations, fields	Complex reports
Gas terminal	Gas input	Sales gas
Gas liquid terminal	Raw gas	Sales gas LPG, condensate
Pipeline allocation	Gas entry	Gas outlets
LNG allocation	Gas in	LPG, LNG, condensate

10.1.2 Well allocation and well production

The principles for well allocation as summarized in Table 11 are the same whether the wells are connected at topside or subsea. The main difference is access for maintenance, taking samples of the fluid and performing well tests. These activities are more challenging with subsea equipment. The wells of subsea equipment are usually monitored by multiphase meters or virtual meters which usually involves increased measurement and allocation uncertainties.

Well performance, which is defined as well theoretical production in this document, is established using flowrates from well testing, performance curve or shrinkage factors based on (bottom-hole) pressure and temperature and online time defined by choke opening and wing valve position on the Christmas tree. The uncertainty of well theoretical production depends on how often well tests are performed and the stability of well production.

The well theoretical production is weighted against the export measurements, field allocated production or sales figure to give the related well production of oil, gas and water from each well for a given period.

Table 12 gives a list of practices used for production well estimations, measurements and allocation.

Table 12 — Well production allocation practices

Flow sampling/ measurement	Sampling/analysis	Well flow calculation	Balance	Allocation
Well test by test separator Oil, water, gas	PVT/periodic single-phase sampling	Theorical well production Conversion to export conditions using process parameters	Achieved by allocation	Pro rata on volume basis for each phase Uncertainty based allocation
WGFM/MPFM on each well	PVT from sampling and from reservoir simulation	Conversion to export conditions using process parameters	Achieved by allocation	Pro rata on volume basis on each phase Uncertainty based allocation
Virtual metering on each well	PVT from sampling and from reservoir simulation	Conversion to export conditions using process parameters	Achieved by allocation	Pro rata on volume basis for each phase Uncertainty based allocation

Figure 13 illustrates a daily gas well allocation set up with all inputs and outputs data in volumes at standard conditions.

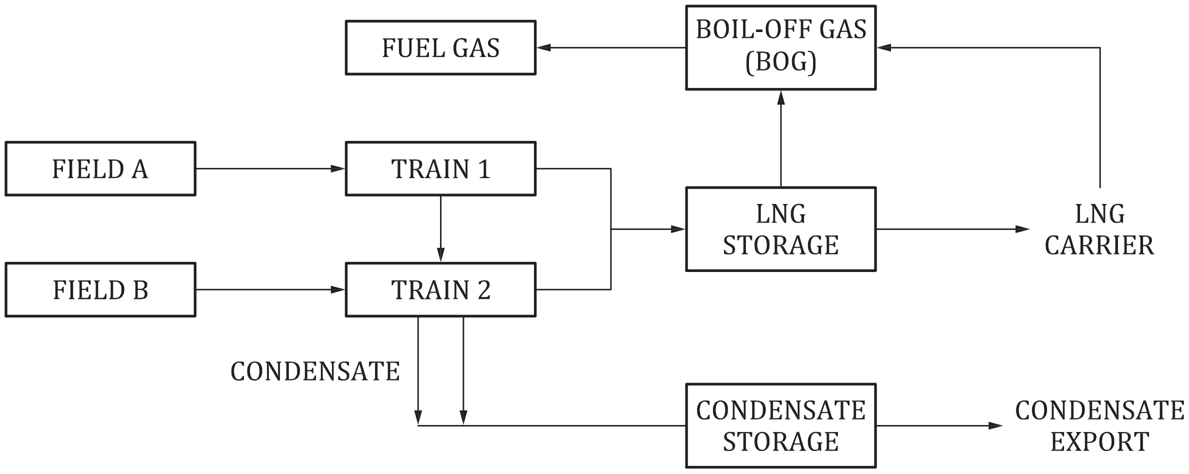


Figure 13 — Well allocation sequences

10.1.3 Asset, field and subgroup, upstream allocation

When several fields are tied into a common process facility either directly or as a subgroup, the production rate shall be determined between the incoming fields or subgroups in the common comingled outgoing stream either to a pipeline or cargo shipment for oil/condensate. The production allocation principles described in Clause 7 are used for the asset/field/upstream allocation.

If there are subgroups of fields tied in with a common riser, the allocation shall take place in steps. The first step is production allocation to the sub-group and then to the individual fields in the subgroup using the allocation principles described in Clause 7.

10.1.4 Pipeline, midstream allocation

An allocation system for wet or rich gas is more challenging than dry gas. If gas is transported over a very long distance, it is preferable that it is dry and lean or match the sales quality requirements. The rich gas shall be processed at a terminal or plant before further transportation to the sales point. At the plant, the heavier components are separated and sold as liquid products, for example NGL cargo shipments.

Mass-component allocation is the preferred allocation system when used on systems that deliver both gas and hydrocarbon liquids through the same pipeline. This process accommodates the exchange of components between the gaseous and liquid phases that takes place in shared treatment and transportation facilities. This method also enables streams with differing hydrocarbon qualities to be more equitability allocated than by other non-component-quantity allocation methods.

When the travel time and/or the volume in the pipeline is large, the inventory can make a significant difference to the allocated figures. If a field is connected to the gas transportation network at an entry point different from that of other fields, its production is transported only through part of the gas pipeline. The part of the inventory upstream of this entry point shall be differentiated from the downstream part. The gas inventory masses in each of the pipeline sections are calculated as before. Care is taken that the calculations include only the fields that contribute to the calculated inventory. The total inventory of the fields furthest upstream in this transportation system is the sum of the inventories of these fields calculated in the two sections of the gas pipeline.

10.1.5 Terminal, downstream allocation

At the terminal the quality of the incoming and outgoing streams shall be determined based on component mass to get the full understanding of the separation. The separated volumes will contain different combination of hydrocarbons and thereby the value of a Sm^3 gas will be different and not give a fair trade. Online gas chromatographs should be used. Since gas volume is affected by pressure and temperature, the inventory of the plant/terminal is significant. LNG allocations follow the principles described in Clause 7, but where normally heat is applied in hydrocarbon process/transportation facilities, cooling is necessary to avoid flashing and entering the two-phase region.

10.1.6 Liquid natural gas

At an LNG plant, several products in addition to LNG like condensate, LPG, naphtha, etc., are possible.

LNG plants can represent the extreme of gas/condensate allocation systems. In most gas/condensate systems, the liquids represented by the condensate are usually a by-product. However, in LNG plants, most of the gas is liquefied and hydrocarbon liquids are the main product. Nonetheless, the allocation principles and measurement methods are essentially the same.

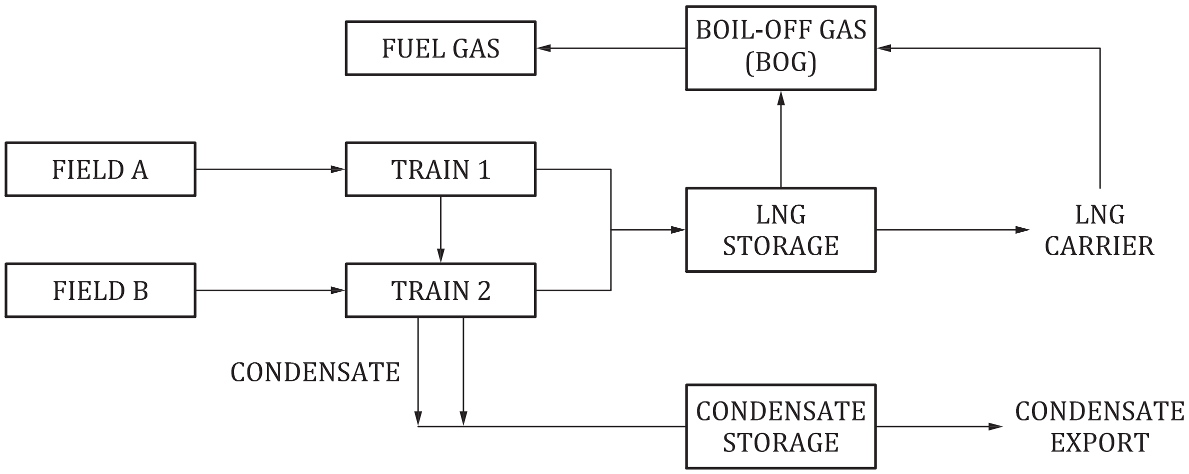


Figure 14 — LNG plant simplified set up

10.1.7 Carbon dioxide CO_2

CO_2 plants for carbon capture and storage (CCS) represent a specific gas facility that requires specific allocation procedures. In CCS plants, extracted CO_2 is liquefied and exported both in vapor phase and in liquid phase for storage. The allocation principles to be used are preferably mass and component.

10.1.8 New development tied into an existing one

Many pipeline systems have strict entry regulations on the quality of metering and on the quality of the products exported from fields into the pipeline. It can simply be impractical commercially to negotiate a new entry point to a pipeline owned by many partners, as this can mean renegotiating complex agreements. It is often more attractive for a new development to be tied into an existing one, making use of the existing entry point to the transportation system. A sub-allocation agreement is required to deal with the sub-allocation of products allocated to the entry point under the main transportation agreement. Usually, the new field is required to meter its products to a reasonably high standard. The high-quality metering at the export point into the transportation system now meters the commingled flow of the existing and new fields. It is usually not economic to install high-quality metering for the products from the existing field, and process metering is usually of a significantly lower standard. In these circumstances, production from the existing field is determined by subtracting the production of the new field from the total production exported into the transportation system.

Allocation by difference can operate as well on a mass-component-based allocation system as on a quantity-based allocation system.

Additional new fields may be added, provided that they are metered to a reasonable, agreed accuracy. The sub-allocation can be made from the shared export point into the transportation system with one field, not metered.

It is necessary to take care when using this approach for the following reasons:

— The uncertainty in the measurements from the existing field increases significantly and can affect the partner's shares, or government taxes if the different fields are taxed at different rates.

— The allocation schemes described in 7.4 have an in-built check for errors in that the sum of the input production equals the output production within the uncertainty of the meters. With allocation by difference, this check is lost, and errors are less obvious.

— The un-metered field is the "balance" for the sub-allocation, and it bears the consequences of any errors in the metering of the other fields.

10.1.9 New development tied into an existing transportation system.

A gas producer may feed the production from one or more fields into its own transportation system. At the end of the transportation system, there may be further processing before the gases and liquids are exported through high-accuracy export meters. If the equity in the fields is the same, and they fall under the same taxation schemes, it is possible that it is not necessary to have an accurate allocation system. It can be sufficient to base the company internal allocation system on the process standard measurements.

For various reasons, a gas producer may allow another gas producer to transport gas/condensate in the transportation system. Here, the issue of high-accuracy allocation arises. The obvious solution is to install high-accuracy allocation metering on each field inlet into the transportation system. This is often considered too expensive for the original gas producer, who can be required to install a number of metering stations. Similarly, it is possible that the new gas producer is not willing to pay to install the metering stations for the installations of the original gas producer. The compromise is for the new producer to install high-accuracy metering at the inlet into the transportation system, and for the total production of the original producer to be determined by difference between the export meter at the end of the transportation system and the metering of the new field. It is necessary to draw up an allocation-by-difference agreement.

10.2 Typical allocation lay out

10.2.1 Gas only

10.2.1.1 Description

It is necessary to characterize the gas flowing through a "gas only" system as "dry." Such a system can possibly use an alternative means, apart from the allocation and metering system in question, to export the hydrocarbon liquids.

If it is assumed that no hydrocarbon liquids are produced from the field or are transported through the measurement node, this shall be stated in the allocation agreement, together with the required steps to take if hydrocarbon liquid products are received at the measurement node. Such liquids should be defined as either a valued or a waste product, and there should be a method specifying how to determine ownership.

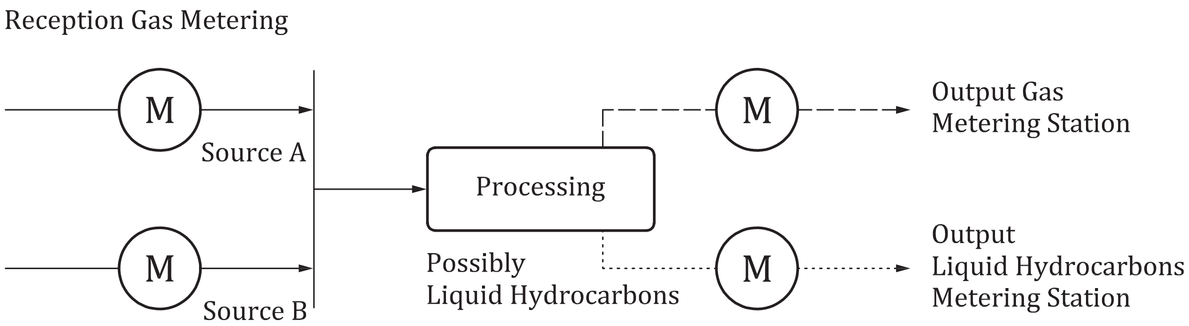


Figure 15 — Gas-only system

10.2.2 Dry gas in, dry gas and liquid out

The layout in Figure 15 is used where liquids drop out during processing or where two-phase flow is present. It removes the need for wet-gas metering. Further processing can be required to enable the gas to meet the entry standards to a distribution network.

An additional meter may be used to measure the quantities removed through the final processing stage. This can be necessary if the source streams have significantly different qualities.

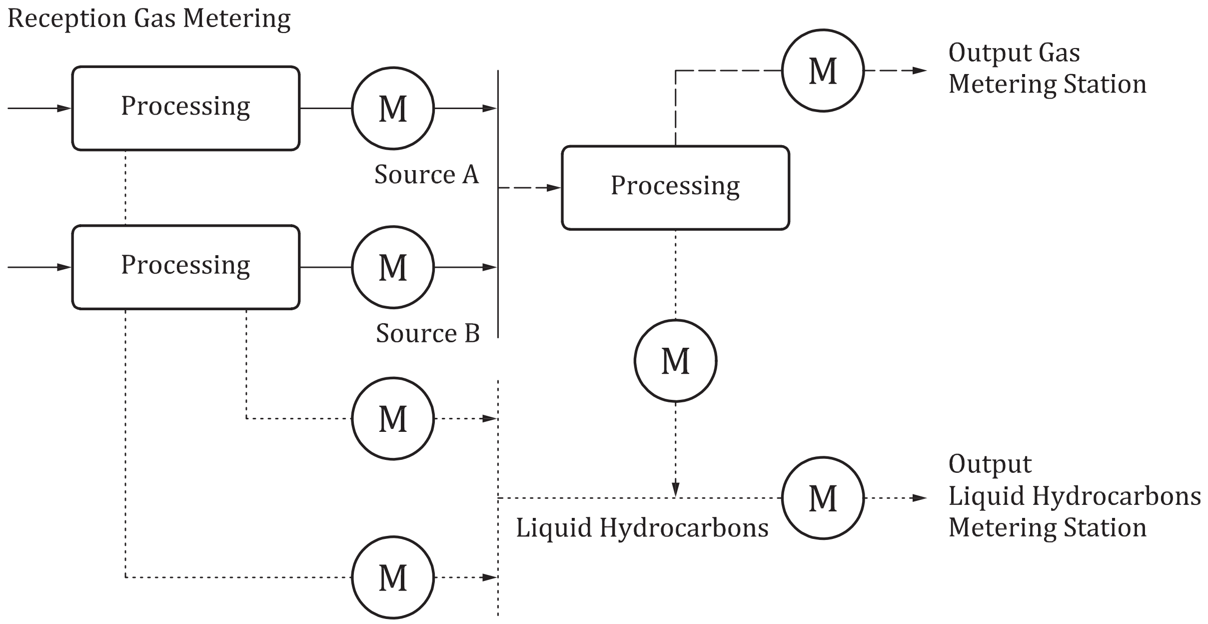


Figure 16 — System with dry gas and liquid in, dry gas and liquids out

10.2.3 Wet gas combined in, dry gas and liquid out

An input measurement node is required to meter a two-phase flow, possibly subsea.

Separators or a slug-catcher may be used to remove liquids prior to processing.

An additional liquid-hydrocarbon meter may be used to measure the hydrocarbon liquid quantities removed through the final processing stage. This can be necessary if the source streams have significantly different qualities.

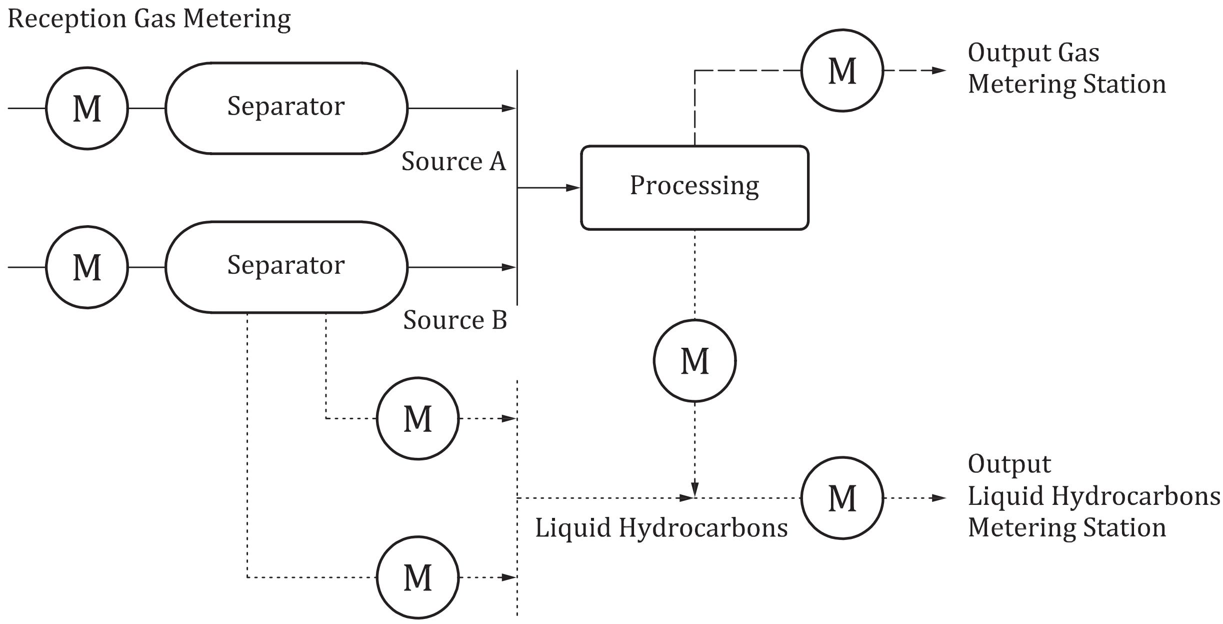


Figure 17 — System with wet gas in and dry gas and liquid out

10.2.4 Dry gas and liquid in; dry gas and liquid out

10.2.4.1 Description

This process applies where hydrocarbon liquids are transported separately from the gas stream. Liquids from sources A and B may be combined at the hydrocarbon-liquid inlet, source A, and split using process simulation or CGRs, or the phases may be transported and metered separately.

An additional meter may be used to measure the quantities removed through the processing stage. This can be necessary if the source streams have significantly different qualities.

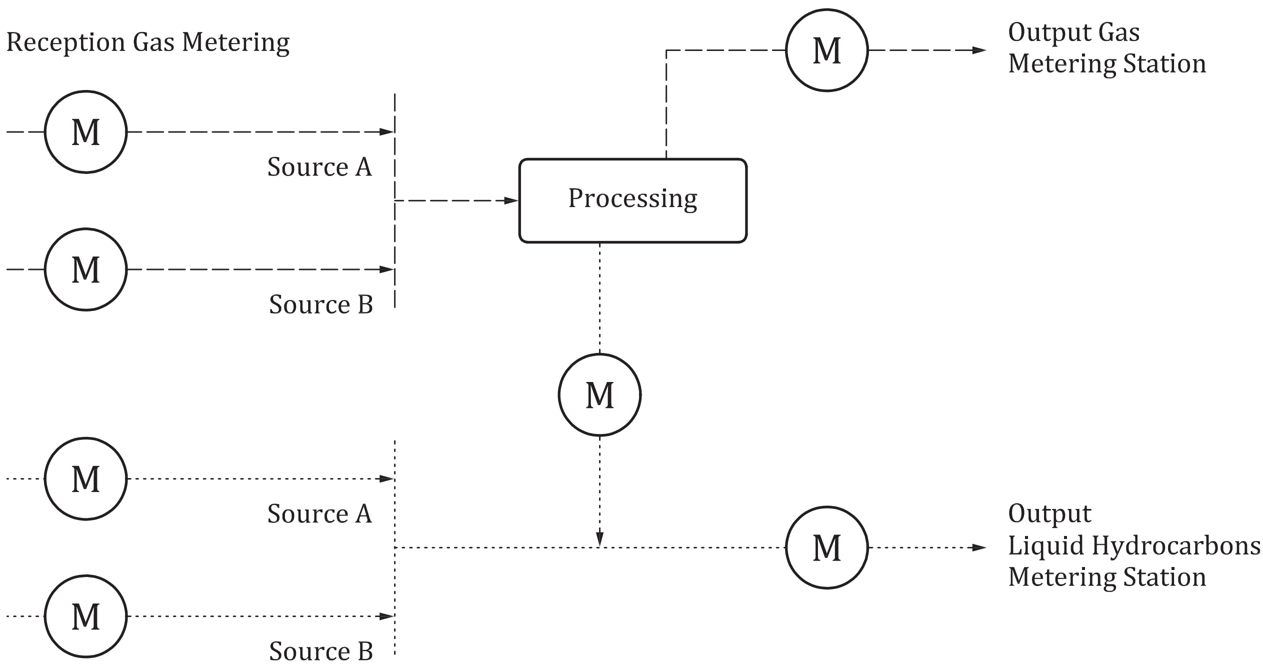


Figure 18 — System with dry gas and liquid in, dry gas and liquid out

11 Allocation uncertainty (from HM 96)

11.1 General

For any allocation system, the uncertainty of the system is directly related to the uncertainty of the inputs. Most systems provide accurate measurement of the export streams. However, the user is ultimately paid for the allocated exports, and the allocated production quantities are based on other, often less accurate, measurements as well as on allocation parameters which also have uncertainties. No matter how robust the allocation method, if there is a high level of uncertainty in the measurements or calculations, the allocated products will have a high level of uncertainty.

Improved measurement reduces allocation uncertainty but increases costs. Any measurement improvements should be justified by a cost-benefit analysis, based on reduced uncertainty in the allocated quantities. To carry out a cost benefit analysis, it is necessary to understand the theory of uncertainty as well as the exposure to loss (see Annex A) and how to determine this in a system.

The uncertainty of calculated values depends on two elements:

— the absolute measurement uncertainty of the inputs to a calculation;

— the calculation itself.

In a complex system with many calculations, the uncertainty of the allocated quantities can be much higher than the uncertainty of the original measurements. Calculation of complex system uncertainties is a specialized area of expertise and is discussed in detail in Reference [29] and ISO/IEC Guide 98-3.

11.2 Relative and absolute uncertainty

When uncertainty is expressed as a percentage, this is a relative uncertainty (ε).

Uncertainties can also be expressed in unit of measurement, e.g. ±2 Sm^3/hr. This is an absolute uncertainty (U).

$$U_X = \varepsilon_X * X$$

where

U_X is the absolute uncertainty of variable *X;*

ε_X is the relative uncertainty of variable *X* (dimensionless);

X is the quantity of variable *X.*

It is important to note that the uncertainty of a measurement device is dependent on the installation, maintenance and operation of the device, as well as the manufacturer's quoted uncertainty. Manufacturers advertise instruments with an accuracy percentage, which only applies under a certain set of reference conditions and can be unachievable or unsustainable during typical operation.

11.3 Uncertainty of a calculated value -analytical solution

A method for combining the uncertainty of independent input variables is defined in ISO/IEC Guide 98-3:2008, Formula (10) This provides an analytical approach to calculating the sensitivity of a value.

In allocation, the most useful applications of this analytical approach are calculating uncertainties of simple by-difference and proportional systems. For more complex systems, the mathematics can be unwieldy, and other methods are recommended.

This method only applies to independent variables. For example, if the uncertainty for each component in an analysis determined by chromatograph is known, these cannot be combined to obtain an overall compositional uncertainty for the stream. In a composition, the components are inter-dependent; therefore, co-variance factors would have to be included in the calculations (see Reference [6]).

For allocation by difference, the absolute uncertainty of the result (the by-difference stream) is the root sum of the squares of the absolute uncertainties of the input variables. This relationship also applies to any additive formula, such as calculation of produced gas from export plus fuel plus flare.

$$U_R = \sqrt{(U_A)^2 + (U_B)^2 + (U_C)^2}$$

For any calculation where the result is calculated from the product of the input variables, the relative uncertainty of the result is the root sum of the squares of the relative uncertainties of the input variables. This relationship cannot be applied directly to proportional allocation, as that includes a summed term.

$$\varepsilon_R = \sqrt{(\varepsilon_A)^2 + (\varepsilon_B)^2 + (\varepsilon_C)^2}$$

For more complex calculations, the analytical solution quickly becomes unwieldy. For example, for a simple 2-party proportional system:

$$Q1 = Q * \frac{X1}{X1 + X2}$$

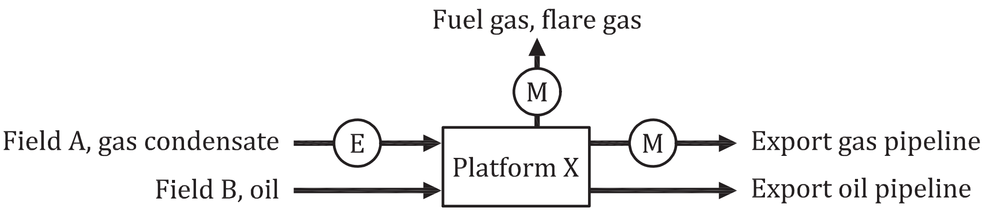
The absolute uncertainties of Q1 and Q2 are calculated from:

$$(U_{Q1})^2 = \frac{X_1^2}{(X_1 + X_2)^2} * (U_Q)^2 + \frac{Q^2}{(X_1 + X_2)^4} * \left[X_2^2 * (U_{X1})^2 + X_1^2 * (U_{X2})^2\right]$$

$$(U_{Q2})^2 = \frac{X_2^2}{(X_1 + X_2)^2} * (U_Q)^2 + \frac{Q^2}{(X_1 + X_2)^4} * \left[X_1^2 * (U_{X2})^2 + X_2^2 * (U_{X1})^2\right]$$

For derivation of the sensitivity coefficients in the above formulae, reference should be made to specialized documents.

11.4 Allocation per difference



Key

E estimate (e.g. from well testing)

M measurement

Figure 19 — By difference allocation of produced gas from Platform X

Figure 19 presents an example of allocation by difference, and the example is detailed in Table 10, with uncertainty calculations also shown.

Table 12 — Allocation by difference of produced gas from Platform X

Inputs	Quantities, Q Or *B* (tonne/d)	Relative uncertainty of quantity, Ɛ (%)	Absolute uncertainty, *U* (tonne/d)
Measured export gas	2 400	1	24
Measured fuel gas	300	3	9
Measured flare gas	221	4	8,84
B_1, field A estimate	2 175	5	108,8
Calculations		**Relative uncertainty (%)**	**Absolute uncertainty[7] (tonne /d)**
Q, produced gas	2 400+300+221 = 2 921	27,1/2 921*100 = 0,9 %	$\sqrt{(24^2+9^2+8{,}84^2)}$ = 27,1
Q_1, produced gas allocated to field A = B_2	2 175	5 %	108,8
Q_2, produced gas allocated to field B	2 921-2 175 = 746	112,1/746*100 = 15 %	√(27,12+108,82) = 112,1

When considering allocation by difference, the relative quantities provided by each user shall be taken into account. The intuitive method is to measure the dominant quantity, and to calculate the minor quantity. However, this results in high uncertainty for the calculated quantity.

Table 13 illustrates the significance of the relative flowrates in a by-difference calculation.

Table 13 — Allocation by difference of produced gas from Platform X

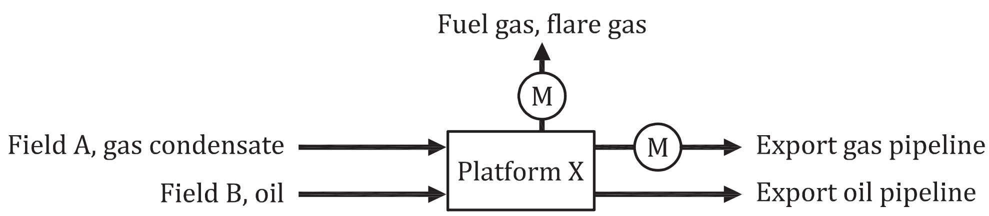
Produced gas flow, *Q*, (tonne/d)	Field A flow, Q_1, (tonne/d)	Field B flow, Q_2, (tonne/d)	Field A uncertainty, ε_1	Field B uncertainty, ε_2
2 921	2 175	746	5 %	15 %
2 921	1 600	1 321	5 %	6,4 %
2 921	1 000	1 921	5 %	3,0 %

The lowest uncertainty for the calculated quantity (field B flow) is achieved when the measured stream (field A) has the smallest flow. A small absolute uncertainty when measuring a large quantity becomes a large relative uncertainty for a small quantity.

When allocating by difference, the known quantity should be the flowrate of the smaller stream.

11.5 Proportional/pro rata allocation

Figure 20 presents an example of proportional allocation, and the example is detailed in Table 14, with uncertainty calculations also shown.



Key

M measurement

Figure 20 — Proportional allocation of produced gas from Platform X

Table 14 — Proportional allocation of produced gas from Platform X

Inputs	Quantities, Q or B (tonne/d)	Relative uncertainty of quantity, Ɛ (%)	Absolute uncertainty, U (tonne/d)
Measured export gas	2 400	1	24
Measured fuel gas	300	3	9
Measured flare gas	221	4	8,84
B_1, field A estimate	2 175	5	108,8
B_2, field B estimate	733	5	36,7
Calculations		**Relative uncertainty (%)**	**Absolute uncertainty (tonne/d)**
Q, produced gas	2 400+300+221 = 2 921	27,1/2 921*100 = 0,9 %	$\sqrt{(24^2+9^2+8{,}84^2)}$ = 27,1
			Absolute uncertainty
Q_1, produced gas allocated to field A	2 921*2 175/ 2 908 = 2 185	43,9/2 185*100 = 2 %	43,9
Q_2, produced gas allocated to field B	2 921*733/ 2 908 = 736	39,5/736*100 = 5,4 %	39,5

The uncertainty of the allocated produced gas is lower when using proportional allocation than when by-difference allocation is used. Because estimated gas production is available for field B, there were redundant data. Using this additional data to perform a proportional allocation reduces the overall uncertainty in the system.

It is a common misconception with proportional allocation that, if the estimated streams have the same relative uncertainty, the allocated streams will have the same relative uncertainty. This is incorrect, because the allocated uncertainty is a function of the square of the absolute uncertainty. The relative flowrates also affect the uncertainty of the allocated values.

11.6 Uncertainty based allocation

In the proportional allocation example in Clause 5, the uncertainty of the field gas estimates was the same for both fields (5 %). Consider the scenario where the accuracy of field B estimated gas improves, perhaps by installing a meter instead of using well tests. In this case, the uncertainties in the allocated produced gas would be as shown in Table 15.

Table 15 — Uncertainty-based allocation of produced gas from Platform X

	Produced gas allocated to field		Relative uncertainty in produced gas allocated to field	
	Field A, (tonne/d)	Field B, (tonne/d)	Field A, (%)	Field B, (%)
Estimated gas production for field	2 175	733		
Field B 5 % uncertainty, proportional allocation	2 185	736	2,0	5,4
Field B 5 % uncertainty, uncertainty-based allocation	2 187	734	1,9	4,8
Field B 3 % uncertainty, proportional allocation	2 185	736	1,7	4,5
Field B 3 % uncertainty, uncertainty-based allocation	2 187	734	1,5	2,9

With proportional allocation, although the uncertainty for Field B input fell, field B is still allocated a proportional share of the cumulative uncertainties in the system. However, the uncertainty-based allocation system gives more weight to the field B estimated gas input and minimizes the overall uncertainty for the system.

11.7 Uncertainty of a calculated value – other methods

Although the analytical approach described in 11.3 is robust, the mathematics can become unwieldy for more complex systems. A variation on this technique is to calculate the partial derivatives by perturbation.

For a calculated value, R = function (A, B, C), the value of each independent input is varied by a small amount, holding all other inputs constant, and calculating the effect this has on the calculated value. The sensitivity coefficient is the ratio of the change in R to the change in A, and similarly for B and C. The combined uncertainty in the calculated value, R, can then be calculated as described in ISO Guide 98-3.[6]

An alternative method is to use a stochastic approach. This involves performing calculations for many cases, using random inputs within the spread defined by each input's uncertainty. Variation in the calculated quantities can then be evaluated to determine their uncertainty. This approach is commonly referred to as the Monte Carlo technique. An extremely large number of cases are required to give a statistically meaningful result and the analysis is usually performed in an automated computer package.

The main advantage of the Monte Carlo technique is that dependency between terms in the allocation equations and any non-linearity is automatically considered.

There has been much debate on various methods of constructing models to combine uncertainty, focusing on the detail such as advantages or disadvantages of using Monte Carlo techniques or finite difference techniques. However, differences between these techniques are often insignificant when compared with the uncertainty in the input quantities. When selecting a method of combining uncertainties, the solution should be based mainly on flexibility and ease of use and maintenance.

11.8 Uncertainty contributors

Uncertainty contributors in an allocation system are measurement, sampling, analysis results and the calculations. Measurement uncertainty is based on relative reliable data and proved by testing. Oil and gas sampling uncertainty is not stated in any standard and it is difficult to give exact numbers since the sampling uncertainty is related to each installation and flow regimes. Lab work and analysis is also based on relatively reliable data and proved by testing. Allocation calculation is based on acceptable assumptions which can be questioned how it in the end influence the results. The calculation itself as mathematic is usually correct.

Statistics can be used to define uncertainty in the sequence or resolution of measurements, sampling, analysis and calculation. For example:

— mass measurement versus volume measurement;

— flow proportional sampling versus spot sampling or no sampling;

— distillation versus true boiling point analysis;

— Karl Fisher titration versus centrifuge usage in determination of water in oil;

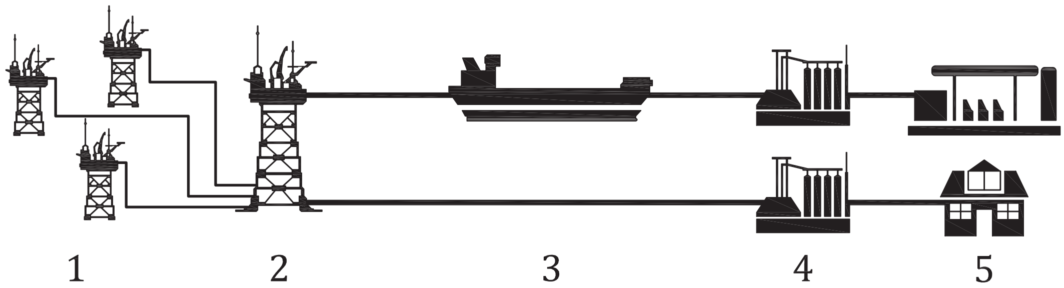
— simulation tools and methods for recovering factors versus calculation.

12 Allocation systems design and integration

12.1 General

There are several allocation issues along the value realization chain. One can either see the chain as one allocation system or the value chain can be divided into subjects or areas: upstream, midstream and downstream. Usually, the operator holds software and programs for the areas in charge. An asset operator only deals with allocations related to tie-ins and facility production: well, field, utility gas, environmental discharge, value adjustment and fees. See Figure 21.

Table 16 gives an overview of activities related to a hydrocarbon value realization chain. A specific list is based on contractual agreements in the chain illustrated in Figure 21.



Key

1 wells production facility
2 processing facility
3 transportation cargo/pipeline
4 plant
5 market

Figure 21 — Hydrocarbon value realization chain

Table 16 — Allocation activities

Subject or area	Well	Pipeline or riser	Facility in	Facility	Facility ex or pipeline in	Pipeline	Pipeline ex or terminal in	Terminal	Terminal ex	Market
Production	Forecast Well testing Theoretical	Inventory	Tie-in Utility gas Measurement Sampling	Separation factors (ORF, shink etc) Inventory Utility gas	Oil Gas Measurement Sampling	Inventory/filling Utility gas	Measurement Sampling	Separation factors Inventory Utility gas	Dry gas NGL Condensate Oil Products Measurement Sampling	Measurement Sampling
Allocation	Well	Field or sub group		Facility or field Utility gas Fees		Pipeline		Terminal/Shipper Utility gas Fees		
Fees				Operation fees Value-adjustment Environmental CO_2 duty CO_2 quotas Nox duty		Transportation Value adjustment		Operation fees Value-adjustment Environmental CO2 duty CO2 quotas Nox duty		Distribution Transportation
Sale or buy				Utility gas Injection gas	Lifting accounts Cargo sale			Lifting accounts Cargo sale Pipeline sale		Product sale
Reports	Well informations Forecasts		Tie-in from facility operator	Production Operation Environmental discharge Allocation Fees Sale or buy Partner	From facility operator	From pipeline operator	From pipeline operator	Production Operation Environmental discharge Allocation Fees Sale or buy Partner	From terminal operator	Invoice
Authority reports	Yes			Yes		Yes		Yes		
Data	Well information	Pressure Temperature Leaks		Operation Environmental Fees COVA	Measurement Sampling Offshore laboratorium	Pressure Temperature Leaks				
Data system data exchange	Reservoir	Operator central control (OCC)	Measurement Laboratorium	Measurement CC	Measurement Onshore laboratorium	Operator central control (OCC)		Shipper		

12.2 Metering and allocation philosophy

An allocation philosophy should be developed that describes both measurement and calculation to put in place as well as the main components of the allocation system.

It is important to consider measurements and allocation together to optimize allocation system.

Allocation systems reflect agreements and comply with regulations in place.

12.3 Allocation agreements

An allocation system is generally based on a commercial agreement between users, often called the allocation agreement. The allocation agreement should communicate the intent of the allocation system to the users and contain the rules which define the system. It is helpful if the aims and principles of the allocation system are developed in conjunction with the agreement. This reduces the likelihood of over-defining the rules (which can lead to inflexibility for future changes in operation) or under-defining the rules (which can result in lack of definition and hence lack of control).

It is common practice to divide the allocation agreement into two parts. The allocation rules are signed by all partners to indicate acceptance. The rules may specify the allocation aims and principles. As the rules are legally binding, they shall be approved by a lawyer.

The rules also typically include provision for audit of the allocation system and challenge of the technical schedules, stating the circumstances under which a change may be made (e.g. evidence of bias or non-compliance with the agreement), and the timeframe for response by the operator.

The technical schedules normally form the second part of the agreement and should specify the allocation method to be used, including formulae and definitions. These should be complete and unambiguous. It is important to specify the methods and constants to be used for any unit conversions or base conversions (e.g. mass to volume), and the limits of measurement uncertainty.

The allocation agreement also often specifies a user's rights to audit the allocation system, and the extent of the operator's obligation to rectify any bias detected.

12.4 Regulations

When developing or modifying an allocation system, it is advisable that the relevant regulatory authorities are advised and consulted at an early stage.

The process should conform to ISO 9001:2015, Clause 7.

During the planning stage of a development project, all regulatory requirements relating to metering and allocation should be identified. Where necessary, advice should be sought from the regulatory authority. Once the requirements are known, any potential problems can be identified e.g. permissions that may have to be in place before the project can commence. Subsequent requirements are more easily accommodated if good communications with the authorities are maintained.

12.5 Development procedure

12.5.1 General

This subclause outlines the overall procedure for developing an allocation system. Clauses 4 to 7 describe the principles and methods which may be used and provide guidance regarding advantages and disadvantages of the various solutions which may be adopted.

The development of an allocation system comprises four key steps as illustrated in Figure 22. Each step has several components, and the process is iterative, as discussed below.

The process can be applied to new allocation systems, or when adding new users to an existing allocation system. When adding new users, the initial aims and principles will normally be in accordance with the existing system. The development process should conform to ISO 9001:2015, Clause 7.

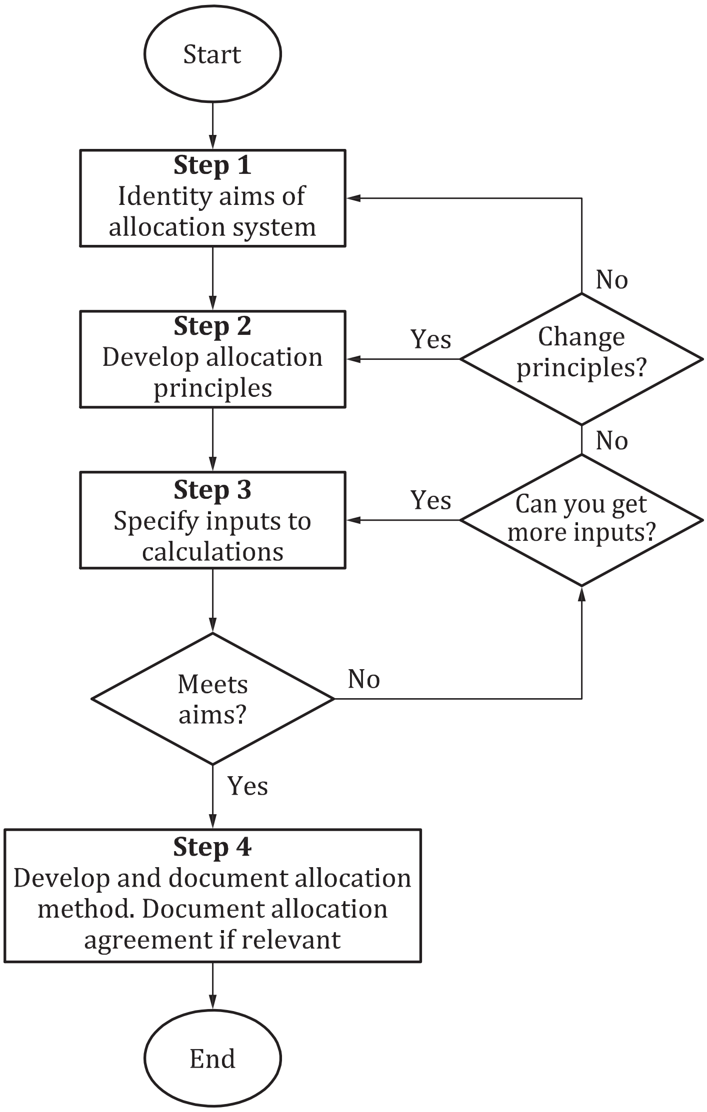


Figure 22 — Development of an allocation system

12.5.2 Step 1

The first, and most important, step is to define what the allocation system is required to achieve.

These requirements may include:

— meeting contractual requirements between users (commercial agreements);

— conforming to reporting requirements: statutory and contractual and including provision of data to downstream systems;

— the ability to record mismeasurements and to assess their impact on the allocated quantities;

— meeting specified uncertainties of products allocated to users: this depends on the users' attitude to the risk of exposure to bias;

— complying with physical constraints, e.g. processing capacities, dedicated processing trains;

— providing for ease of maintenance and possible future modifications to reflect changing needs, e.g. addition of new equipment or new users;

— accommodating operational considerations, e.g. availability of allocation personnel, where the responsibility lies for capture and reporting of raw data and whether the data is automated, manual or both;

— meeting IT requirements, e.g. operating within a particular hardware or software framework.

The aims and principles of the allocation system should be developed in conjunction with the allocation rules. However, it is common practice for the aims and principles to be agreed in a commercial forum, and for the allocation system and rules to be developed later.

12.5.3 Step 2

The allocation principles should typically define:

a) the units to be used (e.g. mass, volume) and the components to be allocated, for example:

   1) produced gas, oil and water;

   2) fuel gas and flare gas (this has become more important in some countries in recent years, with the introduction of greenhouse gas emissions legislation and trading schemes);

   3) export gas and oil;

   4) flash gas;

   5) other feed or product streams, e.g. gas lift, injection fluids, pipeline condensate;

   6) well streams.

b) the allocation method to be used (e.g. by-difference, proportional, process modelling, value adjustment) for each component;

c) the level to which streams are to be allocated, e.g. field, group, owner;

d) data for reporting purposes at facility and user levels, typically for:

   1) production reporting;

   2) environmental management and reporting;

   3) regulatory compliance;

   4) oilfield management and reporting.

12.5.4 Step 3

The third step is to identify the input data which are required for the calculations, and to confirm that these inputs are, or will be, available. This is more straightforward for an existing process, because process and instrumentation diagrams/process flow diagrams will normally be available.

Measurement data for allocation purposes should, where possible, be collected electronically, as this reduces both operator workload and the risk of transcription errors.

At this stage, it is necessary to review whether the allocation principles, together with the input data available, meet the aims of the allocation system.

If the aims cannot be achieved, iteration is required as shown in Figure 22. It may be possible to meet the aims by obtaining additional inputs to the system (i.e. improving measurement or obtaining additional flow estimates from e.g. process simulation). If this is not possible, it may be necessary to revise the principles to fit the available data. It may even be necessary to review the aims of the system and return to the users and/or the regulatory authority to obtain formal agreement to modify the system aims.

12.5.5 Step 4

The documented aims and principles should be circulated to all interested parties (e.g. users, regulators) for review and approval.

Typical system principles can be as follows:

— The allocation will be performed on a mass basis.

— Export gas and oil for field A are measured.

— Export gas and oil for field B are determined by difference between the commingled export meters and the field A export meters.

— Fuel gas is allocated in proportion to export oil for each field.

— Flare gas is allocated in proportion to export gas for each field.

— All water quantities are allocated in proportion to estimated water production for each field.

— Produced gas, oil and water are allocated to wells in proportion to estimated production for each well.

Further documentation of the detailed calculations (the method) is essential for specification and implementation and for validation and maintenance of the system when in operation. This documentation is for people who are directly involved with developing, operating and auditing the allocation system.

The detailed method should be made available to any user on request. However, if the aims and principles are clearly communicated and agreed, providing details of the calculations can be counter-productive, as the intent can be lost in the detail.

If the allocation agreement and allocation system are developed jointly, the allocation agreement must be fully documented and circulated to all relevant interested parties for review and formal agreement.

13 Operation of allocation systems

13.1 General

Operation of an allocation system(s) is multi-discipline tasking comprising:

— collection of data from many sources in due time (measurement, analysis results, operation, production etc.);

— validation of the incoming data;

— computation of the data, issue and distribution of the reports in due time;

— re-runs due to data correction to internal or external data;

— IT-support (access, software upgrades, related IT-services/upgrade to other it-systems, data communication, etc.);

— management of changes (measurements, data, streams, etc.);

— problem solving;

— communication within and outside the organization.

Figure 23 is an illustration of the data flow from instruments and metering computer system offshore via data servers to the main database. Calculation and allocation programs are executed to provide production data to the customers and receive data as data files or another electronic format. The complexity makes allocation systems among the most advanced system for an operator. Strong data skills shall be used to have a smooth operation.

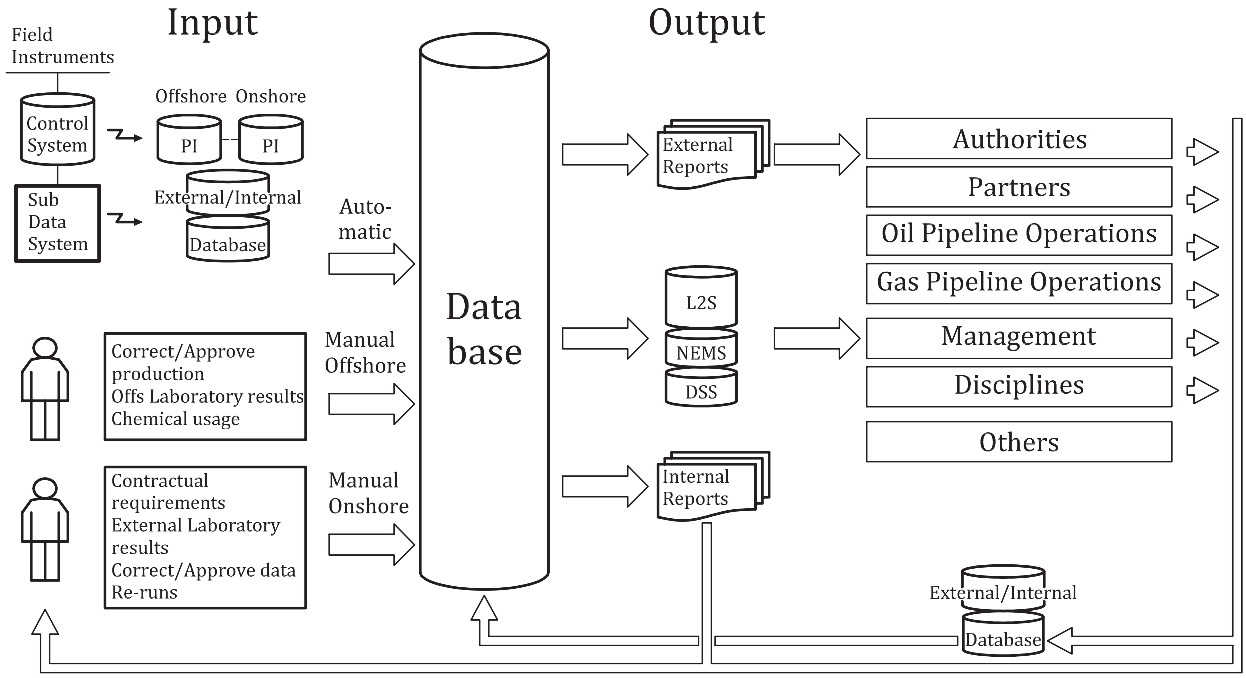


Figure 23 — Data handling

Work processes shall be documented in detail and kept updated. A list of contact persons including their email addresses shall be prepared. Email lists according to the reports' distribution list makes it easy to send out information in case of curtailments/data problems /correction /re-runs etc.

Work processes can be daily, weekly, monthly, quarterly, half yearly and yearly computing of data.

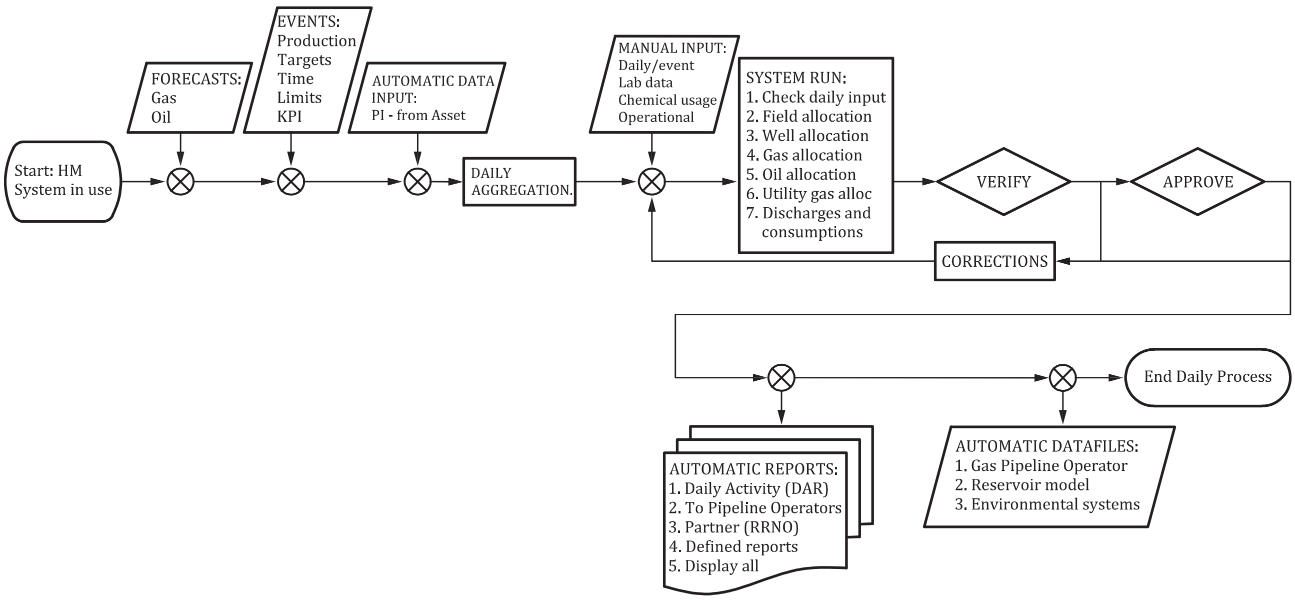


Figure 24 — Example of a daily hydrocarbon management process

The principle is similar for the different work processes:

— input of data;

— start issue;

— verification of the in- and output data;

— if necessary, approval and issuing of distribution reports, lifting accounts and datafiles.

The aim is to have the work processes as automated as possible with data robots etc.

13.2 Input QA/QC

All parties or departments involved in the agreement shall ensure that the issues affecting all allocation factors are properly and adequately dealt with in the agreement. They shall develop the business processes to manage the day-to-day operation of the agreement. Responsibilities and ownership shall be established for the following:

— hydrocarbon stream meter data;

— hydrocarbon stream analysis;

— production forecast information;

— allocation system operation.

Development of the business processes requires a review of almost all departments within a gas production organization to ensure that the workload associated with the operation of the allocation system can be performed adequately and to identify whether additional personnel or external resources are required.

Discussions are required with the project team to ensure that:

— the necessary metering devices are provided to the specified uncertainty levels;

— sampling systems are installed to obtain adequately representative gas and condensate samples;

— acceptable and appropriate analyses of the gas and condensate samples are performed;

— the required data are captured and transferred to a central IT system and an adequate production-measurement management system is in place (see ISO 10012).

Parties involved in these discussions include the metering and IT departments and, where appropriate, the operator of the gas treatment facilities.

The validated meter data should be made available to the hydrocarbon accountants to run the allocation calculations and generate the allocation reports. It is necessary that the validation process for the metered data be performed independently of the allocation calculations. There is a tendency to use allocation processes as a check on the quality of the metering process. Balance factors or reconciliation factors may be used, with care, to highlight possible metering problems. Ideally, limits to these factors should be set based on sensitivity studies with the intrinsic uncertainties of the individual meters as input.

Pressurized samples of gas and condensate are sent to a laboratory that has been selected for the shared pipeline system. The selected laboratory should have appropriate, acceptable accreditation.

Procedures should be developed for:

— control and maintenance of the sample vessels;

— transportation of pressurized sample vessels between the production facilities and the laboratory;

— receipt and validation of the sample fluids;

— conducting and reporting of the analyses.

13.3 Imbalance follow up

When operating an allocation system, there are a variety of allocation boundaries for which imbalances are closed in the allocation process by the allocation calculation itself or prior to the allocation by different approaches as discussed in 4.12 and 7.13.

It can be useful either for technical allocation or contractual/commercial allocation to assign maximum imbalance figures to allocation systems and to follow and monitor such imbalances during operation before allocation and corrections.

13.4 Trending

The operator of an allocation system shall be responsible for analysing the changing trending of allocation data and setting up or configuring the trending figures.

If at any time during an allocation agreement period, the trending gets worse, like for instance an increasing deviation in allocation data, the operator shall carefully analyse the root cause and find out a solution to address it.

The recorded trending data is used to assist in selecting the metering instruments and improve the metering system and allocation system design.

13.5 Surveillance

The operator of an allocation system shall supervise the performance quality of the allocation system. It is necessary to configure an alarm function if there is an error or malfunction arising from the allocation system. The allocation system shall be monitored and be subjected to continuous quality control by the operator.

The parties shall agree to put in place an operation manual including an error correction procedure before the allocation system is put into service.

The allocation operator shall maintain and operate the allocation stock accounts, books and records as well as the deliveries of co-mingled gas according to the allocation agreement.

The operator of the allocation system shall ensure that the statements, information and records are maintained as required under an allocation agreement. The operator shall provide all communications which any of the parties is obliged or required to give by an agreement. This includes estimates, information, nominations, notices, notifications, reports, records and statements.

The allocation operator shall simultaneously act as the agent for each of the parties. Without prejudice to the results arising from performing (or failing to perform) the duties and functions of the allocation operator, the parties shall not be liable for any loss or damage arising from performing (or failing to perform) its duties and functions irrespective of negligence or breach of duty on the basis that the allocation operator has met the standard of a reasonable and prudent operator.

The parties shall, at the request of either party, meet promptly at the allocation operator offices to discuss and endeavour to settle any dispute which arises from the application of the provisions of the allocation agreement. If within 30 days after such request the parties have been unable to reach agreement either party may refer the matter to an expert for resolution.

13.6 Validation

13.6.1 General

Validation is a critical part in the process of establishing confidence in any allocation system.

In this clause, validation includes all action implemented to establish confidence in the final data.

Validation includes all verification and calibration known for equipment as well as more global approaches to check data consistency, such as data reconciliation.

The method depends on the techniques used to determine product quantity and quality as well as on the allocation methods.

Validation in the following areas is considered:

- meters;
- analysers;
- samplers/systems;
- reported quantities (data);
- calculations and modelling;
- allocation process.

Each area has different requirements for validation. However, the process of validation invariably consists of an initial validation before use and subsequent periodic validations while in use to demonstrate that the systems are performing as intended. The interval between periodic validations in each area may be set by specifications in the relevant agreements between partners. The interval often depends on the performance of the area of the system during validation. Successful performance can allow the interval between validations to be extended. This is particularly the case where new technology is involved and periodic verification can be carried out more frequently to establish the quality of the measurements over time. On the other hand, when there are marked changes in the produced fluids over time, it can be necessary to increase the frequency of periodic validations.

13.6.2 Meter validation

13.6.2.1 Initial validation

Initial validation may include:

- metrology checks;
- conformance with relevant standards;
- flow calibration reflecting the expected in-service flowing conditions.

13.6.2.2 Periodic validation

Validity of a meter at the actual flowing conditions has a strong influence on the integrity of the overall measurement system.

The objective of periodic validation of the meter is to ensure that changes to the meter and its operating environment throughout the lifetime of the production facility do not result in unacceptable degradation of the measurements. This may include:

- physical inspection;
- calibration and calculation checks of primary and secondary elements of the system;
- removal of equipment for comparison against a recognized reference standard;
- using diagnostic checks available with certain types of equipment;
- validation by difference, e.g. by shutting a flowing product stream to check its influence.

13.6.3 Allocation procedures and process validation

13.6.3.1 Initial validation

Clear descriptions of the allocation system and the calculations employed in each of the calculation areas shall be established. Calculations for allocation purposes may be carried out in the field using onsite flow computers, in-facility control systems, in-company offices and, in very large allocation systems, at centralized locations.

Verification of interfacing of different parts of the system shall be carried out. Validation of the subsystems is usually by agreed acceptance testing, involving testing by use of “signature” checks where known data inputs have expected or pre-calculated outcomes. System models that replicate key areas of the system may be used, e.g. important calculations, timeliness of results (i.e. processing time), balance checks, factor checks. Full “end-to-end” checks from the measurement equipment on each production facility to the reports (results) should be carried out.

13.6.3.2 Periodic validation

Under normal circumstances, periodic validation of the allocation system is done only when any change is made to the system. The allocation system should be designed with inbuilt checks to warn of faults, precluding the requirement for extensive, difficult-to-implement, periodic validations.

13.6.4 Data validation

At the various nodes within an allocation system, checks are made to ensure the validity of the data that is reported and calculated, to reduce the possibility of product misallocation due to data corruption by whatever means.

13.6.5 Data reconciliation

Data reconciliation is a process that involves comparing and aligning data from multiple sources to ensure consistency, accuracy and integrity. The primary purpose of data reconciliation is to identify and resolve discrepancies or differences between data sets and make them consistent.

Statistical data reconciliation uses redundant data to check data consistency according to expected uncertainty and reduce the uncertainty of other inputs. For example, if there are measured flowrates for two well streams which are produced via a common manifold, and there is also a flow measurement for the combined flows, data reconciliation will provide a new set of data and pinpoint erratic measurements.

This can be done automatically as a pre-processing step, before using the values for allocation.

13.6.6 Process-model validation

Process-model validation may be done by varying the process-plant operating conditions and then checking if the results compare with those predicted by the model. If necessary, the model parameters may be updated to reflect operational experience from such a validation methodology.

13.6.7 Allocation-process results validation

13.6.7.1 Allocation-process trial results

Trial results are usually run before final allocation results (reports) are produced. This can be, for instance, because sample analysis data are not yet available, and an assumed composition is used. The trial results are checked to ensure they lie within predetermined limits to assure their validity.

13.6.7.2 Allocation-process results

Once all the final data are available, the allocation system is run to determine the results. Before the final results are accepted and issued, they are checked to ensure they lie within predetermined limits to assure their validity.

13.6.8 Software validation

13.6.8.1 Initial software validation

The software for an allocation system is comprised of several program packages written by different suppliers. These program packages interface to provide the complete allocation system. Each of these packages should be well specified, especially regarding the interfaces with other packages. It is necessary to validate each package, when produced, against its specification and then, when incorporated into the overall allocation system, relative to the interfaces with other packages.

13.6.8.2 Periodic software validation

The allocation system should be structured so that there are built-in checks to give confidence that the software is working correctly. Periodic validation is required when a software package is modified or upgraded, and it is necessary to check thoroughly both the package itself and its interfaces with the rest of the allocation system.

13.7 Mismeasurement handling

Measurement and allocation incidents can occur from time to time. Some allocation procedures have defined fallback routines for this purpose. This is especially necessary in case of a particular repetitive failure. However, most incidents are relatively unique and cannot be resolved by standard procedures. Most incidents originate from measurement failures; some are due to human error; others are caused in the hydrocarbon accounting process.

A mismeasurement situation arises when a change to the previously reported data is required.

For example, when an error is discovered in a stream measurement. If the incorrect data reported initially had been used as an input to the allocation calculations, this can impact the allocated quantities for the period. The procedure for handling mismeasurements is frequently included in the contractual obligations of the operator.

The normal method for determining the effect of a mismeasurement on allocated quantities is to repeat the allocation calculations for the period using the revised input data. This is generally performed offline, i.e. without interfacing with the database or other reporting system. Any changes to the allocated quantities can then be processed as agreed by the users.

For an allocation system with stocks or banks, changes in allocated quantities can be processed quite simply by altering the balances. Where this is not possible, it may be necessary to come to a commercial (financial) compensation arrangement. Commercial arrangements can become quite complex, especially if a mismeasurement situation exists over a long period (e.g. due to faulty or incorrectly calibrated instrumentation).

It can be advantageous to include mechanisms, e.g. banks, in the system specifically for the application of mismeasurements, and especially where such mechanisms help avoid the need to rerun the allocation. This approach also helps in situations where sales contract periods have closed and cannot be reopened.

It may be necessary to report the changes in allocated quantities to a downstream system, so that they, in turn, can perform a mismeasurement procedure.

Human errors, such as typographical errors and errors in the allocation mechanism, are often traceable and can be corrected by a rerun or recalculation of the allocation process. This recalculation shall normally be done over the full time-base period of the allocation procedure, often on a monthly or sometimes on a daily basis.

In many cases, a corrective calculation is based on assumptions or estimations. Discussions with parties affected is then necessary. In these cases, an estimation of the uncertainty of the correction is necessary. In case of disputes or serious doubts, an independent expert opinion may resolve the issue.

14 Audits

14.1 General

Audit of allocation system is recommended not to limit to the allocation part but also to look at measurements which give input data to the allocation systems.

14.2 Metering and allocation audit objectives

The typical objectives of metering and allocation (MandA) audits are to propose actions for improvement and to check:

— compliance with regulations;

— compliance with agreements, if any;

— compliance with relevant technical standards and audited company rules;

— measurement and allocation system performance;

— error or risks of errors in measurement and data used for taxation, royalty calculations, etc.: this may be based on production data analysis for a given period of time (audited period);

— work process in place within the operator's organization for metering and allocation tasks including stocks measurements and calculations;

— existence of a control and management system in place in the operator's organization.

14.3 MandA audit boundary and activity

14.3.1 Installations

Installations subjected to MandA audits may be:

— specific oil and gas fields;

— production facilities: onshore/offshore/subsea, etc.;

— laboratory: in house, external;

— offloading systems;

— transportation systems;

— pipeline systems;

— storage facilities;

— terminals;

— plants (LNG, etc.).

14.3.2 Systems

The systems to be audited are:

a) measurement systems used either for:

   1) custody transfer and/or;

   2) contractual allocation and/or;

3) fiscal purposes.

b) sampling and analysis (in-line and laboratory);

c) material balances systems;

d) allocation and accounting systems;

e) volume/mass calculations and reporting;

f) environmental measurement system (fuel and flared gas, venting, produced water, etc.);

g) computers and data processing, integrity and security.

14.3.3 Metering and allocation activity

MandA activities are complex and involve several work processes, entities and people in the audited operator's organization.

The MandA audit scope should specify which activity/work processes are to be audited:

— metering operation and maintenance;

— sampling;

— metering calculations;

— metrology;

— material balance;

— allocation;

— value adjustment;

— hydrocarbon accounting;

— loading and inventories (oil, gas, etc.);

— laboratory analysis;

— QA/QC and system management in place.

Bear in mind that activity names, work process and workflows depend on the operator organization, so the final list of work processes and people to audit is not known until the MandA audit preparation stage or sometimes until the actual audit.

14.4 Audit scope

A preliminary scope should be prepared and proposed to the operator for discussion, comment and acceptance.

The preliminary audit scope should specify:

— the main objectives of the audit;

— the period and data on which the audit will focus, where applicable, e.g. one specific year;

— the audit boundary, stating the oil and gas fields as well as installations covered;

— the metering and allocation systems to be examined;

— the particular activities and processes to be audited.

14.5 Audit findings

14.5.1 General

Auditors' findings should be presented as early as possible during the audit. They should be numbered sequentially, reviewed and classified by the lead auditor prior to release. If an issue is contentious or arguable, the lead auditor should first consult with their team.

The findings may be classified in:

— audit exceptions (AE);

— audit recommendations (AR);

— audit observations (AO).

14.5.2 Audit exceptions

An AE is a finding that identifies either commercial, financial or "factual" (verifiable and not only potential) anomaly or error in quantity or a non-conformity.

The AE may be classified as M for monetary if there is an error on quantity which affect revenues or as P if it is procedural or both.

14.5.3 Audit recommendations

An AR is a finding corresponding to a weakness or risks of errors or deviations.

An AR does not relate to lack of compliance with regulation, standards, agreement, internal rules or metering or allocation errors. However, an AR can have significant consequences and generate nonconformity or errors if they are not considered.

14.5.4 Audit observation

An AO occurs when the auditor wishes to highlight a particular point raised during the audit, without requiring answer or follow up from the operator. This AO can be a positive (or negative) observation concerning a process, a methodology, an organization etc.

An AO is not subject to any follow-up after audit completion.

14.5.5 Allocation audit checklist

This document covers audits of allocation processes and results. It is recommended to audit measurement and analysis systems to address the quality of input data and have an overall view of the complete measurement and allocation system.

The main allocation issues to be analysed by means of interviews and documentation review are as follows:

— allocation: general principles, organization, and responsibilities;

— key people/function in charge of data collection, data validation, calculations, reporting;

— specific allocation work processes;

— allocation tools;

— imbalance calculations;

— deviations criteria;

— allocation process for daily, monthly and yearly reporting;

— allocation documentation and handbooks;

— corrections;

— composition data;

— simulation data;

— parameter follow-up;

— validation;

— value adjustment process.

In addition to compliance with agreements, the main resulting indicators can be:

— allocation uncertainty;

— imbalances (mass, volumes, energy) values versus time;

— reconciliation factor;

— allocation factor variations/deviations;

— shrinkages/CGR/yield factors/oil recovery factors values/variations;

— complexity: the system should be easy to understand;

— transparency;

— misallocation reports/corrections;

— number of reruns.

Annex A
(informative)

Exposure to loss/risk assessment

This Annex describes the formula that quantifies the exposure or risk of loss of gas due to allocation uncertainty (see Reference [36]), which is given by Formula (A.1):

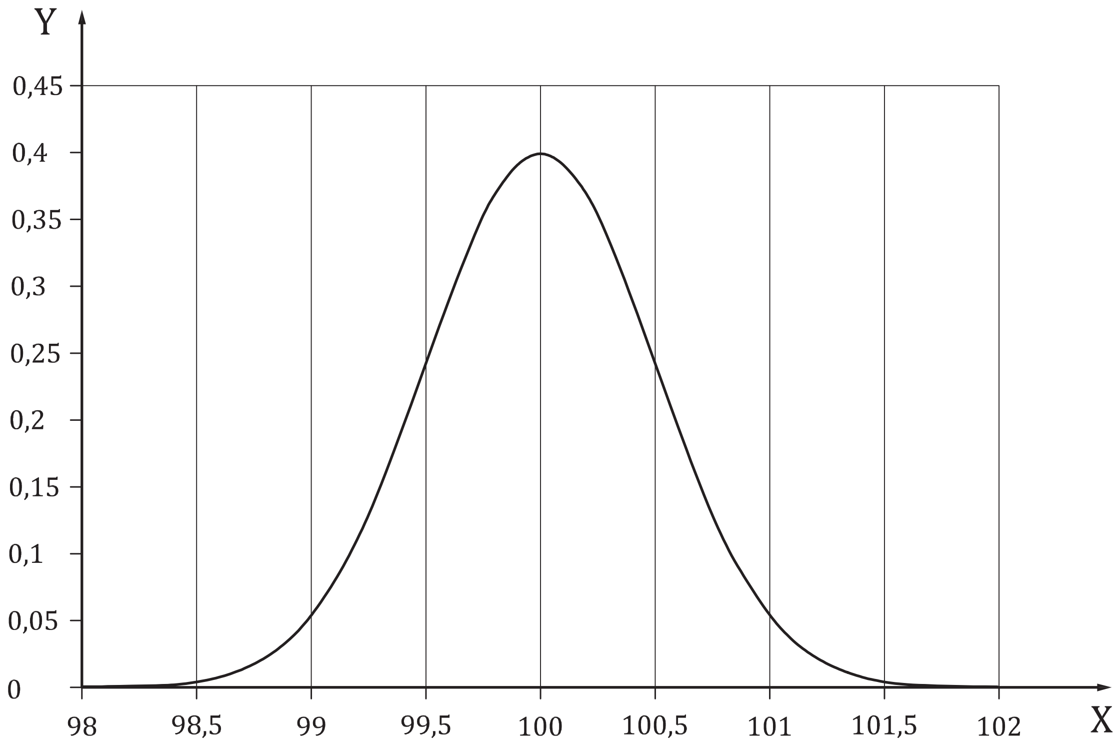
$$L = \frac{U_{\text{abs}}}{k\sqrt{2\pi}} \tag{A.1}$$

where

L	is the integrated risked exposure to loss of allocated gas;
U_{abs}	is the absolute uncertainty of allocated quantity;
k	is the coverage factor associated with the expression of the uncertainty (multiplier of the standard uncertainty);
L and U_{abs}	are expressed in consistent units.

Similar formulae can be used for gas and associated liquids as well to calculate the exposure of risk of loss due to measurement uncertainty as described in A.4 in allocation by difference set up.

This is derived by considering the probability distribution of an allocated quantity as illustrated, for example, in Figure A.1.



Key

X allocated gas (millions of MJ)

Y probability density function

Figure A.1 — Probability distribution of an allocated quantity

In this example, the true quantity is 100 × 10^6 MJ of gas. Due to the uncertainties in the allocation system (e.g. in measurements, simulation results) any reported allocated quantity will most likely differ from this true value in accordance with a normal distribution as indicated. The spread of this normal distribution is characterized by its standard deviation, which in this case is 0,5 × 10^6 MJ. This standard deviation is numerically equivalent to the standard uncertainty of the allocated quantity, or expressed at the more familiar 95 % confidence level, the uncertainty is 1,96 times this value (0,98 × 10^6 MJ).

For any individual allocation result, there is a chance that the allocated gas falls anywhere along the horizontal axis, but the probability diminishes the further from the mean. Because the allocated gas is normally distributed, the probability or risk associated with any individual under- or over-allocation of gas can be calculated. This probability is proportional to the height of the normal curve at that point.

However, it is the exposure to under-allocation or loss alone that is being considered here, hence just the left-hand side of the plot in Figure A.1, where the allocated gas is less than 100 × 10^6 MJ. It is possible to multiply each potential lost revenue figure by its individual probability of occurrence. This is illustrated in Figure A.1 for a probability of a 0,5 × 10^6 MJ loss of gas (equivalent to 1 standard deviation) by the vertical line at 99,5 × 10^6 MJ. The probability of such a loss is proportional to the height of the normal distribution curve at that point. (The vertical axis indicates the probability density function not the probability itself.)

The product of the magnitude of these individual potential losses and their probability of occurrence can be summed across the full range of potential loss, to give a total risked exposure to loss. As the losses are described by a continuous distribution and each infinitesimal loss figure has an associated probability density, the product of the loss and probability density are integrated. This is the integrated risked exposure to under-allocated gas given by Formula (A.1).

The derivation of Formula (A.1) is presented in Formula (A.2).

The allocated quantity is normally distributed and the probability of a particular allocated value is therefore calculated using Formula (A.2):

$$p=\frac{1}{\sigma\sqrt{2\pi}}e^{\left(\frac{-1}{2}\left(\frac{x-x_T}{\sigma}\right)^2\right)} \tag{A.2}$$

where

p	is the probability density function;
x	is the allocated quantity;
x_T	is the average “true” allocated quantity (100 × 10^6 MJ in the example from Figure A.1);
σ	is the standard deviation of the allocated quantity (equal to standard uncertainty, k=1, 0,5 × 10^6 MJ in the example from Figure A.1).

Each under allocation of revenue (x-x_T) value shall be multiplied by the probability of its occurrence:

$$R=(x-x_T)*p*dx \tag{A.3}$$

Where R is the risked exposure to misallocation of gas and has a negative value for under-allocation (i.e. loss).

The differential dx is required as the probability density function is integrated over a range of x to obtain a probability. Hence, the total risked exposure to loss (R_{Tot}) is calculated by substituting Formula (A.2) into Formula (A.3) and integrating x from minus infinity to x_T:

$$R_{Tot}=\int_{-\infty}^{x_T}\left(\frac{(x-x_T)}{\sigma\sqrt{2\pi}}e^{\left(\frac{-1}{2}\left(\frac{x-x_T}{\sigma}\right)^2\right)}\right)dx$$

This integrates to:

$$R_{Tot}=\left[-\sigma\times\frac{1}{\sqrt{2\pi}}e^{\left(\frac{-1}{2}\left(\frac{x-x_T}{\sigma}\right)^2\right)}\right]_{-\infty}^{x_T}$$

$$R_{Tot}=-\sigma\times\frac{1}{\sqrt{2\pi}}\left(e^{\left(\frac{-1}{2}\left(\frac{x_T-x_T}{\sigma}\right)^2\right)}-e^{\left(\frac{-1}{2}\left(\frac{-\infty}{\sigma}\right)^2\right)}\right)$$

$$R_{Tot}=-\sigma\times\frac{1}{\sqrt{2\pi}}(1-0)$$

Hence, R_{Tot} is given by:

$$R_{Tot}=\frac{-\sigma}{\sqrt{2\pi}}$$

The value of L is the negative of R_{Tot} and σ can be expressed in terms of an uncertainty figure with coverage factor k.

$$L=\frac{U_{abs}}{k\sqrt{2\pi}}$$

Calculating the risked exposure to loss of gas in monetary equivalent terms provides a basis with which to conduct cost-benefit analysis for measurement and allocation systems with differing uncertainties. The extra cost of implementing a system with lower uncertainty can be compared against the reduction in exposure to loss of revenue.

From an allocation perspective, similar principles using calculation of risk of over-allocation or under-allocation R for gas or liquid due to measurement uncertainty may be agreed with stakeholders and further used to estimate correction to apply to a measured stream A with a measurement uncertainty of UA, $_{abs}$ especially in allocation by difference method as per Figure A.2.

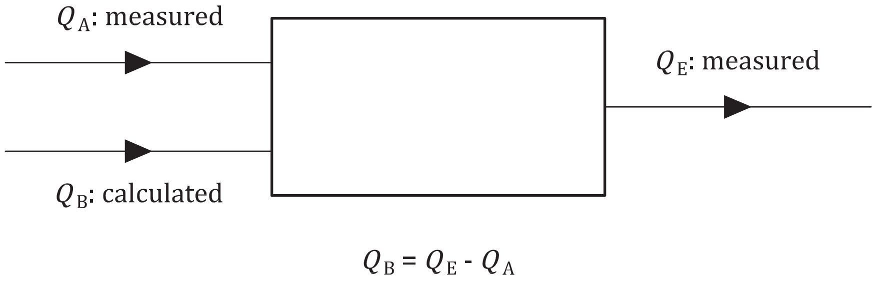


Figure A.2 — Correction to apply to a measured stream

In such a case, the quantity of export gas allocated to A is calculated using Formula A.4

$$Q_{gas}, E, A = Q_A \text{ (measured)} - R \text{ (Risk of over-allocation)} \tag{A.4}$$

The quantity of export gas allocated to B:

$$Q_{gas}, E, B = Q_E - Q_{gas}, E, A$$

where

Q_A	is the measured gas for stream A;
Q_E	is the measured gas at export point E;
R	is the integrated risk of over-allocation with $R = \dfrac{UA_{abs}}{k\sqrt{2\pi}}$;
UA_{abs}	is the measurement absolute uncertainty for A.

For completeness, the risk of over/under-allocation R for stream B should also be listed in this example:

$$R = \frac{UB_{abs}}{k\sqrt{2\pi}}$$

Where UB_{abs} is the uncertainty for the by-difference calculation of stream B, which is affected by both the uncertainty of stream A and the uncertainty of stream E.

NOTE If for normal distribution k=2, other distribution with different probability can also be used and agreed.

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