NORWEGIAN OFFSHORE DIRECTORATE

Guidelines for Regulations relating to fiscal measurement in the petroleum activities (Measurement Regulations)

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Introduction

The Regulations relating to fiscal measurement in the petroleum activities (the Measurement Regulations) are pursuant to the Act relating to petroleum activities (the Petroleum Act) and the Regulations to Act relating to petroleum activities (the Petroleum Regulations), as well as the Act relating to tax on discharge of CO_2 in the petroleum activities on the continental shelf (the CO_2 Tax Act). These Regulations sets requirements for measuring produced quantities of petroleum and quantities subject to CO_2 tax. The objective is to ensure that accurate and reliable measurements form the basis for the calculation of taxes and fees to the Norwegian State, as well as the licensees' revenues from the petroleum activities.

These Guidelines provide supplementary comments on the individual provisions of the Measurement Regulations and descriptions of how the regulatory provisions can be fulfilled. As of 1 May 2023, the Guidelines replace the comments on the Measurement Regulations that were previously included as part of the Regulations. It is structured in the same manner as the previous comments, as each individual provision is addressed. Appendix 1 contains a metrological glossary. Documents recommended for fulfilling regulatory requirements are listed in Appendix 2. Appendix 3 concerns the evaluation of measurement data in connection with measuring fluid flow. Appendix 4 deals with the uncertainty budgets for CO_2 tax measurements.

Re Chapter 1. Introductory provisions

Re Section 1. Objective

First paragraph:

In order to ensure accurate measurements, these Regulations include requirements for the accuracy of measurement results and measuring systems. The accuracy of a measurement result means the degree of accordance between a measured or calculated value and a true value of the measurand (cf. JCGM 200:2012). The accuracy of a measuring instrument or measuring system means a quality that characterises the ability of a measuring instrument or measuring system to provide a value approximate to a true value of the measurand (cf. IEC 60050). In practice, the true value of the measurand is unknown, but it is understood, with a certain probability, to be within a range defined by measurement uncertainty. A measurement result is more accurate if the measurement uncertainty is lower. Correspondingly, a measuring system is more accurate if instrumental measurement uncertainty is lower.

Requirements are set for e.g. management systems, measurement methods and metrological traceability in order to ensure reliable measurements. Reliability means that it must be possible to verify measurements and then yield the same, or no more divergent than probable, result.

Second paragraph:

The licensee can use standards and other recognised documents in order to comply with these regulatory requirements.

According to NS-EN 45020:2006, Item 3.2 and ISO/IEC Guide 2:2004, a "standard" is defined as: ”Standard document established by consensus and approved by a recognized body, that provides, for common and repeated use, rules, guidelines or characteristics for activities or their results, aimed at the achievement of the optimum degree of order in a given context.” A national standard means a standard adopted by a national standardisation body, and international standard means a standard adopted by an international standardisation body. Standards Norway is an example of a national standardisation body. ISO (International Organization for Standardization) is an example of an international standardisation body.

"Other recognised documents" means technical specifications, technical reports and guidelines published by standardisation bodies and by recognised industry and interest organisations. Examples of recognised industry organisations: The International Organization of Legal Metrology (OIML), International Group of Liquefied Natural Gas (GIIGNL) and Offshore Norge. The Norwegian Society for Oil and Gas Measurement (NFOGM) is an example of a recognised interest organisation.

Technical solutions described in relevant standards can usually be considered to be pre-qualified solutions. Nevertheless, it is the licensee's responsibility and duty to ensure that the chosen solutions are expedient.

When technical solutions other than those recommended in the guidelines for a regulatory provision are used, the licensee is responsible for being able to document that the chosen solution fulfils the regulatory requirements.

Appendix 2 refers to standards and other recognised documents that the Norwegian Offshore Directorate considers to be particularly relevant for fulfilling the requirements in these Regulations. The list is not necessarily exhaustive and does not rule out the existence of other relevant documents.

Re Section 2. Scope of application

First paragraph:

These regulatory requirements apply for planning, construction, installation, testing and use of measuring systems for

a) measuring produced quantities of petroleum,
b) measuring quantities of burnt petroleum and natural gas emitted to air, as well as CO_2 that is separated from petroleum and emitted to air.

Pursuant to Section 1-4 of the Petroleum Act, the Regulations also apply for onshore facilities if petroleum is transported to the facility by pipeline from the continental shelf and the measurement takes place onshore in Norway for practical reasons. In such instances, the Norwegian Offshore Directorate will coordinate the supervisory activity with the Norwegian Metrology Service as referenced in the cooperation agreement between the two agencies. At terminals abroad where Norwegian petroleum is landed by pipeline, the Norwegian Offshore Directorate will conduct metrological supervision in collaboration with relevant authorities in the state in question, cf. the second sentence of Section 1-4 first paragraph of the Petroleum Act.

Second paragraph:

MID - the Measuring Instruments Directive (Directive 2014/32/EU of the European Parliament and of the Council of 26 February 2014/EEA Annex to Official Journal of the European Union No. 13/197) harmonises technical requirements for various instrument categories and aims to ensure the free movement of measuring instruments within the EU/EEA area. The Directive is aimed at manufacturers and suppliers of measuring instruments and measuring systems. Measuring instruments and measuring systems covered by the MID must fulfil the Directive's technical requirements before they are made available on the market. The pre-market control entails conducting a conformity assessment through a technical regulatory agency (conformity assessment body) and conformity marking to show that the Directive's requirements are met.

The Measuring Instruments Directive is implemented in Norwegian law through the Regulations relating to units of measurement and measurement (FOR-2007-12-20-1723) and instrument-specific regulations, including the Regulations relating to requirements for measuring systems for continuous and dynamic measurement of fluids other than water (FOR-2007-12-21-1738). The Norwegian Metrology Service is an approved technical regulatory agency for conducting conformity assessments pursuant to the Measuring Instruments Directive.

As regards the petroleum activities, requirements in the MID apply for measuring instruments and measuring systems for dynamic delivery measurements of oil and liquid gases. Special requirements and procedures for conformity assessments are established in Annex VII to the MID, Measuring systems for the continuous and dynamic measurement of quantities of liquids other than water (MI-005). The MID does not cover the parts of the measuring system that involve proving and sampling.

Measuring instruments and measuring systems that are approved pursuant to the MID will also be in accordance with the Measurement Regulations.

Re Section 3. Definitions

A metrological glossary of terms and expressions used in the Regulations and in the Guidelines is provided in Appendix 1 to these Guidelines. The glossary is primarily based on JCGM[1] 200:2012 "International vocabulary of metrology – Basic and general concepts and associated terms (VIM)", 3rd edition (VIM3), and to a certain extent on standards from ISO, IEC and API (cf. Appendix 2). Terminological databases can be found at the following websites:

- Annotated VIM3: https://jcgm.bipm.org/vim/en/index.html
- ISO Online browsing platform: https://www.iso.org/obp
- IEC Electropedia: http://www.electropedia.org

Abbreviations and symbols follow the recommendations from the Language Council of Norway. These can be found at https://www.sprakradet.no/sprakhjelp/Skriveregler/Forkortinger/

Re Section 4. Responsibility according to these Regulations

The first paragraph of this provision entails a material duty to comply with the regulatory provisions and individual decisions made pursuant to the Regulations. The duty to do this by implementing necessary systematic measures follows from Section 5.

[1] Joint Committee for Guides in Metrology, which is a committee with members from BIPM, IEC, IFCC, ILAC, ISO, IUPAC, IUPAP and OIML.

Re Chapter 2. Requirements relating to management systems

This chapter concerns requirements for management systems within the scope of both the Petroleum Act and the CO_2 Tax Act. Reference is also made to Sections 56, 57 and 58 of the Petroleum Regulations.

Re Section 5. Management system

Management systems are the activities, systems and processes that are used to plan, implement, evaluate and correct the activities so that they comply with requirements stipulated in or pursuant to these Regulations.

Appendix 2 refers to documents that can be used to fulfil requirements for management systems.

Second paragraph:

When assessing the risk of failing to fulfil requirements in these Regulations, consideration should be taken as regards the likelihood of errors, the consequences of errors, the likelihood of uncovering errors and the likelihood of correcting for errors.

Fourth paragraph:

Roles and responsibilities should be defined in organisation charts, work descriptions and procedures.

Fifth paragraph:

The requirement to define functions with responsibility for following up measurements and measuring systems can be fulfilled by appointing someone to be responsible for measurements and measuring systems.

Sixth paragraph:

The specification of how to preserve the transfer of competence should include a specification of how to ensure that lessons learned are communicated during personnel changes and in the transition between the construction phase and operations phase.

Re Section 6. Internal audits

The licensee has the flexibility to adapt the purpose, scope and frequency of internal audits as it deems necessary for fulfilling the regulatory requirement.

Appendix 2 refers to documents that can be used to fulfil requirements for internal audits.

Re Chapter 3. Requirements relating to units of measurement and reference conditions

Re Section 7. Measurement units

Appendix 2 refers to documents that can be used to fulfil requirements for units of measurement.

Re Section 8. Reference conditions

Appendix 2 refers to documents that can be used to fulfil requirements for reference conditions.

Re Chapter 4. General requirements relating to measurement

This chapter establishes general requirements for the measurement process, both experimental and mathematical, as well as for the quality of measurements, including measurement results and uncertainty limits.

Re Section 9. Measurement

No comment.

Re Section 10. Measurands and uncertainty limits

<u>First paragraph:</u>

"Petroleum" is all liquid and gaseous hydrocarbons existing in their natural states in the subsoil, as well as other substances produced in association with such hydrocarbons (cf. Section 1-6 (a) of the Petroleum Act).

"Oil" is petroleum which is liquid at the shipment point (cf. Section 2 (f) of the Petroleum Regulations). In practice, this means crude oil and other liquid petroleum products (see the Oil Glossary on the NOD website).

"Net quantity (standard volume) of oil" is the standard volume of oil minus sediment and water. "Net quantity (mass) of oil" is the weight of oil in vacuum minus sediment and water.

The uncertainty limit refers to the value (target figure x measurement unit) of the quantity the measurement aims to quantify.

As regards allocation measurement, the licensee can define other uncertainty limits for measurands than those listed in Table 1, if it can be documented that fulfilling the listed uncertainty limits is not technically feasible or would lead to unreasonably high costs. This exception is primarily intended for situations where produced quantities from a field will be determined through an allocation process that involves measuring unprocessed (multiphase) petroleum or measurements at the outlets of separators (single-stage separation).

<u>Second paragraph:</u>

"Natural gas" comprises hydrocarbons in gas form and mainly consists of methane, ethane and propane, minor quantities of other, heavier hydrocarbons and traces of pollutants such as CO_2 and H_2S, etc. (see the Oil Glossary on the NOD website).

"Quantity (standard volume) of flared petroleum" is the standard volume of flare gas burnt off in a flare and gas burnt off in a pilot burner, potentially corrected for water vapour and inert gasses in the flare gas. Flare gas is gas or vapour vented or discharged in a flare (system for burning off petroleum).

"Quantity (standard volume) of natural gas emitted to air" is the standard volume of natural gas emitted unburned to the air in a flare and cold-vented in dedicated chimneys (cold-venting system), potentially corrected for water vapour and inert gasses.

If it is difficult to satisfy uncertainty limits for flared petroleum and natural gas emitted to air, the licensee can apply to the Norwegian Offshore Directorate for dispensation pursuant to Section 99. The Norwegian Offshore Directorate can grant dispensations for "particular reasons". Examples of "particular reasons" that could necessitate increased uncertainty limits may include:

a) Quantities of natural gas emitted to air during a measurement period that are less than 100,000 standard cubic metres (Sm^3).

b) Quantities of flared petroleum during a measurement period with little or no operational flaring and where inert gas (shielding gas) constitutes the majority of the measured flare gas.

The licensee must document the existence of particular reasons.

Quantities of petroleum burnt during well tests and well maintenance at a facility or an associated facility are taxable and shall be included in a CO_2 tax measurement. The Norwegian Offshore Directorate has not found it to be appropriate to stipulate detailed provisions in these Regulations for how such quantities shall be measured.

It is presumed that the stated uncertainty limits for quantities of diesel used as fuel are reasonable.

Re Section 11. Methods for measuring produced petroleum

No comment.

Re Section 12. Methods for measuring burnt petroleum and gas emitted to air

First paragraph:

Appendix 2 refers to documents that can be used to fulfil requirements in the first paragraph, litra a) for indirect measurement of natural gas emissions.

Re Section 13. Measurement principles

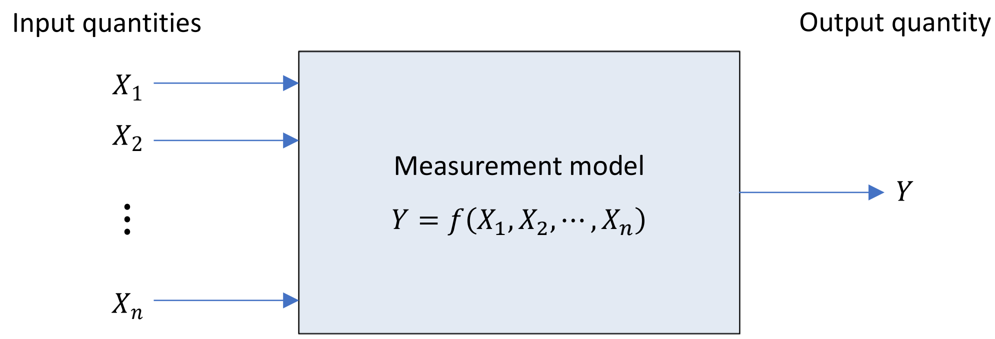
Measurement principles described in relevant current recognised national and international standards for the measurement type in question can normally be used to fulfil the requirement to use measurement principles that are documented as suitable for use in the measurement in question.

Re Section 14. Measurement model

Appendix 2 refers to documents in the "GUM: Guide to the Expression of Uncertainty in Measurement" series issued by the Joint Committee for Guides in Metrology (JCGM). These publications and equivalent publications from other members of the JCGM, including ISO/IEC, are internationally recognised guidelines for evaluating and expressing measurement uncertainty and for the development and use of measurement models.

A measurand can usually be modelled as a functional relationship *f* between *N* input quantities $X_1, \ldots, X_N$ and an output quantity *Y* in the following form:

$$Y = f(X_1, \ldots, X_N)$$



The measurement model can be linked, so that output quantities in one model can be input quantities in another. Measurement models can have more than one output quantity.

Corrections can be applied to both input and output quantities in a measurement model. They can be introduced in the model to compensate for additive systematic effects (absolute) and multiplicative systematic effects (proportional to output quantities or input quantities).

Examples of simplified resulting measurement models with output quantities that correspond to measurands in Section 10 are provided in the guideline for Section 15, along with models to calculate associated measurement uncertainty. The guideline for Section 28 covers measurement models and associated uncertainty models for measuring systems, i.e. systems with output quantities that are input quantities in the resulting measurement model.

Re Section 15. Uncertainty budget

Documents in the "GUM: Guide to the Expression of Uncertainty in Measurement" series published by the Joint Committee for Guides in Metrology (JCGM) and equivalent publications from other members of the JCGM, including ISO/IEC, are internationally recognised guidelines for evaluating and expressing uncertainty in measurement. Appendix 2 refers to these publications. Appendix 2 also refers to other relevant documents and uncertainty programmes published on the Norwegian Society for Oil and Gas Measurement website which can be used to fulfil requirements for uncertainty budgets.

Relevant resulting measurement models and associated uncertainty models for measurands in Section 10 are provided below.

Delivery measurements of oil

A resulting measurement model for delivery measurements of oil could be

$$V_{Net} = (1 - \phi_W) V_{Gross}$$

where V_{Net} is the net standard volume of oil, V_{Gross} is the gross standard volume of oil and ϕ_W is the volume fraction of water in the oil. V_{Gross} is measured using a flowmeter and ϕ_W is determined either through chemical analysis of oil samples, or as a direct measurement. Here, V_{Gross} and ϕ_W are input quantities and V_{Net} is the output quantity. When no correlation between the input quantities is assumed, the uncertainty model becomes equal to:

$$u^*(V_{Net})^2 = \left(\frac{\phi_W}{1-\phi_W}\right)^2 u^*(\phi_W)^2 + u^*(V_{Gross})^2$$

In many instances, the relative uncertainty $u^*(V_{Gross})$ can be found using the uncertainty programme "Fiscal Oil Metering Station Uncertainty" on the Norwegian Society for Oil and Gas Measurement website, which produces the instrumental uncertainty in the flow rate, or using an equivalent computer programme with calculation algorithms that correspond with JCGM GUM. If the measuring system has functioned and been used as intended, one can normally presume that the relative uncertainty is approximately the same in the flow rate and accumulated gross volume. The uncertainty $u^*(\phi_W)$ can be found from laboratory certificates, potentially in combination with uncertainties linked to obtaining and handling the oil samples, or from specifications for measuring instruments used for direct measurement of the water fraction.

As regards delivery measurements of oil based on indirect measurement, one example would involve two fields (Field A and Field B) delivering into the same pipeline. Field B's delivery measurement (net standard volume) is based on direct measurement (measuring system). This also applies for the total net standard volume coming out of the pipeline. The quantity of oil in a delivery from Field A is then measured indirectly as the quantity of oil coming out of the pipeline minus oil delivered from Field B. One relevant measurement model for this situation would be:

$$V_A = V_{total} - V_B$$

where V_B is the accumulated net standard volume delivered from Field B (measured at Field B) and V_{total} is the accumulated net standard volume received and measured at the pipeline outlet. V_A is the accumulated net standard volume delivered from Field A (calculated using the direct measurements of V_B and V_{total}). Here, V_B and V_{total} are input quantities and V_A is the output quantity. When one presumes no correlation between the input quantities, the uncertainty model for the accumulated net standard oil delivered from Field A is as follows:

$$u^*(V_A)^2 = \left(\frac{V_{total}}{V_A} u^*(V_{total})\right)^2 + \left(\frac{V_B}{V_A} u^*(V_B)\right)^2$$

The uncertainties $u^*(V_{total})$ and $u^*(V_B)$ can be found using a methodology for delivery measurements of oil using a single measuring system, as described above.

Delivery and allocation measurement of gas

If the measuring system has functioned and been used as intended, it can normally be presumed that the relative uncertainty is approximately the same in the flow rate and associated accumulated quantity. In many instances, this can be found using the uncertainty programme "Fiscal Oil Metering Station Uncertainty" on the Norwegian Society for Oil and Gas Measurement website, or using an equivalent computer programme with calculation algorithms that correspond with JCGM GUM.

Quantity of natural gas used as fuel for power and heat production

If the measuring system has functioned and been used as intended, it can normally be presumed that the relative uncertainty is approximately the same in the flow rate and accumulated volume. In many instances, this can be found using the uncertainty programme "Fiscal Oil Metering

Station Uncertainty" on the Norwegian Society for Oil and Gas Measurement website, or using an equivalent computer programme with calculation algorithms that correspond with JCGM GUM.

Quantity of diesel used as fuel for power and heat production

A resulting measurement model for the accumulated standard volume of diesel used as fuel could be:

$$V_{diesel} = V_{delivered} - V_{balance} - V_{not\ combusted}$$

where $V_{delivered}$ is the volume of diesel delivered to the installation during a measurement period. $V_{balance}$ is the change in diesel inventory during the measurement period, tax period or a calendar year. $V_{not\ combusted}$ is the volume of diesel used for purposes other than fuel during the measurement period, including well maintenance. If no correlation is presumed between the input quantities, the uncertainty model will be as follows:

$$u^*(V_{diesel})^2 = \left(\frac{V_{delivered}}{V_{diesel}} u^*(V_{delivered})\right)^2 + \left(\frac{V_{balance}}{V_{diesel}} u^*(V_{balance})\right)^2 + \left(\frac{V_{not\ combusted}}{V_{diesel}} u^*(V_{not\ combusted})\right)^2$$

Quantity of flared petroleum

A resulting measurement model for the accumulated standard volume of flared petroleum during a measurement period could be:

$$V_{flared\ petroleum} = \left(V_{flare\ gas\ (lit\ flare)} + V_{gas\ to\ pilot\ burner}\right) - \left(V_{inert\ gas} + V_{water\ vapour}\right)$$

where $V_{flare\ gas\ (lit\ flare)}$ is the accumulated standard volume of flare gas during periods with a lit flare , and $V_{gas\ to\ pilot\ burner}$ is the accumulated standard volume of gas led to the pilot burner. $V_{inert\ gas}$ and $V_{water\ vapour}$ are the accumulated standard volume of inert gas and water vapour, respectively, in the flare gas. If no correlation is presumed between the input quantities, the uncertainty model will be as follows:

$$u^*\left(V_{flared\ petroleum}\right)^2 = \left(\frac{V_{flare\ gas\ (lit\ flare)}}{V_{flared\ petroleum}} u^*\left(V_{flare\ gas\ (lit\ flare)}\right)\right)^2 + \left(\frac{V_{gas\ to\ pilot\ burner}}{V_{flared\ petroleum}} u^*\left(V_{gas\ to\ pilot\ burner}\right)\right)^2 + \left(\frac{V_{inert\ gas}}{V_{flared\ petroleum}} u^*\left(V_{inert\ gass}\right)\right)^2 + \left(\frac{V_{water\ vapour}}{V_{flared\ petroleum}} u^*\left(V_{water\ vapour}\right)\right)^2$$

If the measurement of the quantity of flare gas involves measurement results from multiple meters (e.g. primary meter and secondary meter), this is reflected in the model through multiple input quantities.

As regards measuring systems with an online gas chromatograph, one alternative way to correct for water vapour and inert gas could be:

$$V_{flared\ petroleum} = \left(V_{flare\ gas\ (lit\ flare)} + V_{gas\ to\ pilot\ burner}\right) \cdot f\left(Z_0, X_{natural\ gas}\right)$$

where

$$f\left(Z_0, X_{natural\ gas}\right) = \frac{Z_{0\ natural\ gas}}{Z_{0\ total}} \cdot X_{natural\ gas}$$

where $Z_{0\ natural\ gas}$ is the compressibility factor of natural gas at reference conditions. $Z_{0\ total}$ and $X_{natural\ gas}$ are the compressibility factor and the proportion of natural gas, respectively, in the gas flowing through the measuring system. The quantities included in the correction factor f can be calculated from the flare gas composition. When it is assumed that there is no correlation between the input variables, the uncertainty model is equal to:

$$\begin{aligned} u^*\left(V_{flared\ petroleum}\right)^2 \\ &= \left(\frac{V_{flare\ gas\ (lit\ flare)}}{V_{flared\ petroleum}} u^*\left(V_{flare\ gas\ (lit\ flare)}\right)\right)^2 \\ &+ \left(\frac{V_{gas\ to\ pilot\ burner}}{V_{flared\ petroleum}} u^*\left(V_{gas\ to\ pilot\ burner}\right)\right)^2 + \left(u^*(f)\right)^2 \end{aligned}$$

Quantity of natural gas emitted to air

A resulting measurement model for the accumulated standard volume of natural gas emitted to air during a measurement period could be:

$$V_{natural\ gas\ emissions} = \left(V_{cold-vent} + V_{flare\ gas\ (unlit\ flare)}\right) - \left(V_{inert\ gas} + V_{water\ vapour}\right)$$

where $V_{cold-vent}$ is the accumulated quantity of water vapour and gas emitted to air through a cold-venting system and $V_{flare\ gas\ (unlit\ flare)}$ is the accumulated standard volume of flare gas emitted to air through an unlit flare. $V_{inert\ gas}$ and $V_{water\ vapour}$ are the accumulated standard volume of inert gas and water vapour, respectively, in cold-vent and flare gas. If no correlation is presumed between the input quantities, the uncertainty model will be as follows:

$$\begin{aligned} u^*\left(V_{natural\ gas\ emissions}\right)^2 \\ &= \left(\frac{V_{cold-vent}}{V_{natural\ gas\ emissions}} u^*(V_{cold-vent})\right)^2 \\ &+ \left(\frac{V_{flare\ gas\ (unlit\ flare)}}{V_{natural\ gas\ emissions}} u^*\left(V_{unlit\ flare}\right)\right)^2 \\ &+ \left(\frac{V_{inert\ gas}}{V_{natural\ gas\ emissions}} u^*\left(V_{inert\ gas}\right)\right)^2 \\ &+ \left(\frac{V_{water\ vapour}}{V_{natural\ gas\ emissions}} u^*\left(V_{water\ vapour}\right)\right)^2 \end{aligned}$$

Sources of natural gas emissions listed in the current Offshore Norge guideline "044 – Recommended Guidelines for discharge and emission reporting" can be used to specify input quantities in the resulting measurement model for natural gas emissions.

It can be difficult to determine the measurement uncertainty for minor emissions and indirectly measured emissions of natural gas. Estimates based on good industrial practice can fulfil the requirement in Section 10 to designate an uncertainty limit.

Quantity of CO_2 separated from petroleum and emitted to air

If the measuring system has functioned and been used as intended, it can normally be presumed that the relative uncertainty is approximately the same in the flow rate and accumulated volume. In many instances, this can be found using the uncertainty programme "Fiscal Oil Metering Station Uncertainty" on the Norwegian Society for Oil and Gas Measurement website, or using an equivalent computer programme with calculation algorithms that correspond with JCGM GUM. If the separated CO_2 is not pure, the measurement model and associated uncertainty model must reflect how to determine the quantity of separated CO_2 from the measurements in question.

Examples of resulting measurement models and associated uncertainty models

The two examples below show how a measurement model and an uncertainty model are used to set up an uncertainty budget. Values given for relative uncertainties, coverage factors and relative sensitivity coefficients are examples and are not universal.

Example 1: Uncertainty in indirectly measured quantity of delivered oil
Measurement model:

$$V_A = V_{total} - V_B$$

Input quantity and output quantity:

- Field B delivers 40,000 Sm^3 of oil in the pipeline, i.e. $V_B = 40\ 000\ S\mathrm{m}^3$.
- 100,000 Sm^3 of oil is measured at the pipeline outlet, i.e. $V_{total} = 100\ 000\ S\mathrm{m}^3$.
- This means that Field A delivers $V_A = V_{total} - V_B = 60\ 000\ S\mathrm{m}^3$.

Uncertainties in input quantities:

- On Field B, delivered oil is measured using a measuring system that satisfies the requirements for delivery measurements of oil and where the relative expanded uncertainty with a 95% confidence level for net standard volume in its own studies is calculated to be 0.30%. This means that the relative standard uncertainty is $u^*(V_B) = \frac{0.30\%}{2}$ = 0.15%.
- At the pipeline outlet, delivered oil is measured using a measuring system that satisfies the requirements for delivery measurements of oil and where the relative expanded uncertainty with a 95% confidence level for net standard volume in its own studies is calculated to be 0.25%. This means that the relative standard uncertainty is $u^*(V_{total}) = \frac{0.25\%}{2}$ = 0.125%.

Uncertainty in output quantity:

The relative standard uncertainty in the accumulated net standard volume of oil delivered from Field A ($u^*(V_A)$) can be found using the uncertainty formula stated above:

$$u^*(V_A)^2 = \left(\frac{V_{total}}{V_A} u^*(V_{total})\right)^2 + \left(\frac{V_B}{V_A} u^*(V_B)\right)^2$$

All quantities on the right side are quantified here, thus allowing calculation of $u^*(V_A)$:

$$u^*(V_A)^2 = \left(\frac{100000\ Sm^3}{60000\ Sm^3}\cdot 0.125\%\right)^2 + \left(\frac{40000\ Sm^3}{60000\ Sm^3}\cdot 0.15\%\right)^2 = 0.05340\%^2$$

$$u^*(V_A) = 0.231\%$$

The relative expanded uncertainty in the accumulated net standard volume of oil delivered from Field A can then be found by multiplying by the coverage factor (k = 2):

$$U^*(V_A) = 2u^*(V_A) = 0.46\%$$

This can also be summarised in a table; for example, as follows:

	Stated relative uncertainty	Coverage factor	Relative standard uncertainty	Relative sensitivity factor	Relative variance
Measurement out of pipeline, $\boldsymbol{V_{total}}$	0.25%	2	0.125%	$\frac{V_{total}}{V_A} = \frac{5}{3}$	0.04340%²
Measurement on Field B, $\boldsymbol{V_B}$	0.30%	2	0.15%	$\frac{V_B}{V_A} = \frac{2}{3}$	0.01000%²
Sum of relative variances					0.05340%²
Relative standard uncertainty of $\boldsymbol{V_A}$					0.231%
Relative expanded uncertainty (k = 2) of $\boldsymbol{V_A}$					0.46%

In this instance, and as one can see from the uncertainty budget, the Section 10 requirement for an uncertainty limit of 0.30% is not fulfilled for the measured quantity of oil delivered from Field A.

Example 2: Uncertainty in quantity of flared petroleum

Measurement model (simplified):

$$V_{flared\ petroleum} = V_{flare\ gas\ (lit\ flare)} - V_{nitrogen} = \left(V_{primary} + V_{secondary}\right) - V_{nitrogen}$$

Input quantities and output quantities:

- Primary meter measures 260,000 Sm³ of gas, i.e. $V_{primary} = 260{,}000\ S\mathrm{m}^3$.
- Secondary meter measures 140,000 Sm³ of gas, i.e. $V_{secondary} = 140{,}000\ S\mathrm{m}^3$.
- Correction is measured to be 100,000 Sm³, i.e. $V_{nitrogen} = 100{,}000\ S\mathrm{m}^3$.
- This means that the flared quantity of petroleum is $V_{flared\ petroleum} = V_{primary} + V_{secondary} - V_{nitrogen} = 300{,}000\ Sm^3$.

Uncertainties in input quantities:

- The primary meter is an ultrasonic flare gas meter where the relative expanded uncertainty at a 95 % confidence level in a separate study is calculated to be 5 %. This means that the relative standard uncertainty is $u^*\left(V_{primary}\right) = \frac{5\%}{2}$ = 2.5%.

- The secondary meter is a meter where the relative expanded uncertainty at a 95 % confidence level in a separate study is calculated to be 10 %. This means that the relative standard uncertainty is $u^*(V_{secondary}) = \frac{10\%}{2}$ = 5%.
- The correction is measured using a separate measurement system where relative expanded uncertainty at a 95 % confidence level in a separate study is calculated to be 1.5 %. This means that the relative standard uncertainty is $u^*(V_{nitrogen}) = \frac{1.5\%}{2}$ = 0.75%.

Uncertainty in output quantity:

The relative standard uncertainty in the accumulated net standard volume of flared petroleum, $u^*(V_{flared\ petroleum})$, can be determined based on the uncertainty formula stated above:

$$u^*(V_{flared\ petroleum})^2 = \left(\frac{V_{primary}}{V_{flared\ petroleum}} u^*(V_{primary})\right)^2 + \left(\frac{V_{secondary}}{V_{flared\ petroleum}} u^*(V_{secondary})\right)^2 + \left(\frac{V_{nitrogen}}{V_{flared\ petroleum}} u^*(V_{nitrogen})\right)^2$$

All quantities on the right side are quantified here, thus allowing calculation of $u^*(V_{flared})$:

$$u^*(V_{flared\ petroleum})^2 = \left(\frac{260{,}000\ Sm^3}{300{,}000\ Sm^3} \cdot 2.5\%\right)^2 + \left(\frac{140{,}000\ Sm^3}{300{,}000\ Sm^3} \cdot 5\%\right)^2 + \left(\frac{100{,}000\ Sm^3}{300{,}000\ Sm^3} \cdot 0.75\%\right)^2 = 10.201\%^2$$

$$u^*(V_{flared\ petroleum}) = 3.19\%$$

The relative expanded uncertainty in the accumulated net standard volume of flared petroleum can then be found by multiplying by the coverage factor (k = 2):

$$U^*(V_{flared\ petroleum}) = 2u^*(V_{flared\ petroleum}) = 6.4\%$$

This can also be summarised in a table; for example, as follows:

	Stated relative uncertainty	Coverage factor	Relative standard uncertainty	Relative sensitivity factor	Relative variance
Measurement with primary meter, $\boldsymbol{V_{primary}}$	5%	2	2.5%	$\frac{V_{primary}}{V_{flared\ petroleum}} \approx 0.8667$	4.6944%^{2}
Measurement with secondary meter, $\boldsymbol{V_{secondary}}$	10%	2	5%	$\frac{V_{secondary}}{V_{flared\ petroleum}} \approx 0.4667$	5.4444%^{2}

Measurement of deduction, $\boldsymbol{V_{correction}}$	1.5%	2	0.75%	$\frac{V_{nitrogen}}{V_{flared\ petroleum}} \approx 0.3333$	0.0625%^{2}
Sum of relative variances					10.201%^{2}
Relative standard uncertainty of $\boldsymbol{V_{flared\ petroleum}}$					3.19%
Relative expanded uncertainty (k = 2) of $\boldsymbol{V_{flared\ petroleum}}$					6.4%

As one can see from the uncertainty budget, the Section 10 requirement for an uncertainty limit of 7.5% is fulfilled for the measured quantity of flared petroleum.

Re Section 16. Measurement procedure

A measurement procedure should include a description of how measurement results are obtained and reported, including any calculations. The measurement procedure should also include a designation of uncertainty limits and error limits.

Re Section 17. Measurement result

A measurement result is the final result of the process of determining the values of a measurand.

Re Section 18. Replacement for missing measurement data

If feasible, uncertainty should be estimated for replacement data.

Re Section 19. Correction of measurement results

Examples of "systematic errors in a measurement result" could be errors that are not corrected for in the measurement model and which are caused by factors such as:

- fault (error) in measuring system (equipment that does not satisfy performance requirements),
- deficient compliance with internal requirements and routines (management system),
- incorrectly read values,
- errors in calculations,
- errors in parameters entered in computer systems (incorrect parameters used in calculations).

The following provides guidance for when a measurement result is considered to have a "significant systematic error":

- the systematic error constitutes more than 0.02 % of measured value, and
- the financial value of the error exceeds NOK 20,000, and
- the financial value of the error exceeds the cost of correction.

If it cannot be documented how long the systematic error has been present, one prudent method could be to correct for errors during the last half of the maximum period of time the error may have been present.

Re Chapter 5. Requirements relating to chemical analyses in laboratories

Relevant measurement requirements in Chapter 4, including for documenting compliance with uncertainty limits in the uncertainty budget and metrological traceability, also apply for results from chemical analyses of oil and gas samples.

Re Section 20. Measurands and uncertainty limits

Uncertainty budgets for trace quantities of water in oil samples should be based on uncertainty sources identified and addressed in standards and other recognised documents.

Appendix 2 refers to documents that could be relevant for fulfilling requirements in this provision.

Re Section 21. Requirements for analysis methods

First and second paragraph:

“Other methods” for analysing trace quantities of water in oil samples include the centrifuge method and distillation method.

A “representative test sample” means a test sample (cf. metrological glossary) with a composition that matches the sample it is extracted from, and in which has a quantity that is suitable for the analysis method/analyser. In order to achieve a representative test sample, the sample it is extracted from is presumed to have been homogenised. A sample is homogenised by mixing it with an appropriate mixer for an appropriate period of time.

Syringes used to extract a test sample with a specific volume should have a digital read-out. The volume uncertainty should not exceed 0.5 %. The analytical balance used to weigh a test sample should have a precision of at least 0.1 mg. Simultaneous fulfilment of requirements for the traceability of measurement results in Section 17 presumes that the syringes and analytical balances used to determine the test sample quantity are certified.

Fifth paragraph:

In this context, “reference materials” means solutions used to verify the Karl Fisher analyser's calibration, density standards used to verify the density analyser and calibration gas used to verify the gas chromatographs calibration. Certified reference materials should be used.

Appendix 2 refers to documents that can be used to fulfil requirements for analysis methods.

Re Section 22. Laboratory requirements

Laboratories that are accredited or that can document equivalence as regards competence and management will be able to fulfil requirements for laboratories used for chemical analysis of petroleum.

The Norwegian Offshore Directorate normally arrange an inter-laboratory comparison (ILC) every 2 years of instrumental chemical analysis of trace quantities of water in oil samples. The ILC is considered to be an important measure to ensure the quality of such analyses. Each ILC is summarised in a report. The results from the participating laboratories will be anonymised in the report. In addition to the report, the individual laboratories will receive specific feedback with detailed results from the ILC. All laboratories associated with the petroleum activities on the Norwegian shelf should participate in the ILC.

Appendix 2 refers to documents that could be relevant for fulfilling requirements in this provision.

Re Chapter 6. Allocation requirements

Re Section 23. Allocation system

Appendix 2 refers to documents that could be relevant for fulfilling requirements for allocation systems.

First paragraph:

A fair allocation means an allocation that e.g. does not contain identified biases.

An auditable allocation means an allocation that provides information that can be evaluated step-by-step in an independent manner to achieve the same results.

Re Section 24. Allocation procedures

No comment.

Re Section 25. Verification and validation

The first validation of the allocation system should take place within one year of putting it to use, thus ensuring that timely corrections can be made.

Re Chapter 7. General requirements for measuring systems for dynamic measurement

Requirements in Chapter 7 apply for dynamic measurement of quantities of petroleum flowing through pipes. These requirements must be viewed in context with measurement requirements in Chapter 4. Chapter 7 is supplemented by chapters with special requirements for measuring systems for measuring oil, gas and multiphase petroleum. The requirements in Chapter 7 and in the supplemental chapters apply for the planning, construction, testing and operation and maintenance of measuring systems.

In these Regulations, a “flow of oil” means a single-phase flow of crude oil, condensate or NGL (including LPG). A “flow of gas” means a single-phase flow of dry gas, rich gas, flare gas, cold-vented gas, etc. A “flow of hydrocarbons in multiphase petroleum” means a multiphase flow of petroleum, including flows of wet gas.

A “single-phase flow of oil and gas” means a flow of fluid with a single thermodynamic phase. A “multiphase flow of petroleum” means a simultaneous flow of fluids with two or more thermodynamic phases. In these Regulations, “single-phase” means a thermodynamic system with physical and chemical properties that, for practical purposes, can be considered to be homogeneous.

Re Section 26. Design of measuring instruments and measuring systems

No comment.

Re Section 27. Rated operating conditions

The requirement to document rated operating conditions includes specification of metrological characteristics such as

a) working ranges,
b) type of fluid,
c) the fluid's relevant thermophysical characteristics,
d) pressure range limited by the fluid's minimum and maximum pressure, and
e) temperature range limited by the fluid's minimum and maximum temperature.

Re Section 28. Instrumental measurement uncertainty

Instrumental measurement uncertainty is normally achieved by calibrating a measuring instrument or measuring system. Information that is relevant for instrumental measurement uncertainty can be provided in instrument specifications.

Appendix 2 refers to documents that could be relevant for fulfilling requirements for instrumental measurement uncertainty.

First paragraph:

If the instrumental measurement uncertainty for the relevant measuring system is within the values in the table below, the requirements in Section 28 first paragraph will usually be fulfilled.

Type of measuring system:	Indication	Uncertainty limit
Delivery measurement	Volume or mass flow of oil	0.20%
	Volume, mass or energy flow of gas	0.9%
Allocation measurement	Volume or mass flow of oil	0.3%
	Volume or mass flow of gas	1.4%
	Volume or mass flow of multiphase petroleum	5%
CO_2 tax measurement	Volume flow of natural gas for fuel	1.4%
	Volume flow of gas to flare and cold-venting system	5%
	Volume flow of vented CO_2	5%

Second paragraph:

As regards measuring the flow of oil and gas, uncertainty programmes on the Norwegian Society for Oil and Gas Measurement website, or other programmes based on the guidelines from JCGM “GUM: Guide to the Expression of Uncertainty in Measurement” can be used to prepare and maintain an uncertainty budget for instrumental measurement uncertainty.

As regards measuring the flow of gas to the flare (flare gas) using an ultrasonic flowmeter or other volumetric flowmeter, a simplified analysis can normally be used where uncertainty used in the volumetric flow rate is as specified by the supplier, as well as uncertainty associated with pressure, temperature and gas compressibility factor. In this instance, the measurement model can be written as follows:

$$q_{v0} = \frac{PT_0Z_0}{P_0TZ} q_v$$

where q_v is the volumetric flow rate at the relevant pressure and temperature, P is the relevant absolute pressure, P_0 is the standard reference pressure (=1.01325 bara), T is the relevant absolute temperature (stated in Kelvin), T_0 is the standard reference temperature (=288.15 K, equivalent to 15 °C), Z is the gas' compressibility factor at the relevant pressure and temperature, and relevant absolute pressure, Z_0 is the gas' compressibility factor at the standard reference pressure and temperature, and q_{v0} is the volumetric flow rate at the standard reference pressure and temperature. Here, q_v, P, T and Z/Z_0 are input quantities and q_{v0} is the output quantity.

When no correlation is presumed between the input quantities, the uncertainty model for the standard volumetric flow rate is as follows:

$$u^*(q_{v0})^2 = u^*(q_v)^2 + u^*(P)^2 + u^*(T)^2 + u^*(Z/Z_0)^2$$

where u^* represents the relative standard uncertainty. There is a weak correlation between pressure (P) and compressibility factor (Z) and between temperature (T) and compressibility factor (Z). However, this is so weak for flare measurements that it can be disregarded.

The uncertainty $u^*(q_v)$ will normally be found in the flowmeter's specifications. Correspondingly, the uncertainties $u^*(P)$ and $u^*(T)$ can be calculated based on specifications and calibration results. $u^*(Z/Z_0)$ depends on how this is implemented in the measuring system. This uncertainty can vary with pressure and temperature, in addition to varying with the gas composition. It is not usually necessary to examine the uncertainties in the gas components.

As regards measuring the flow of hydrocarbons in multiphase petroleum, a complete quantitative theoretical uncertainty evaluation will usually not be possible.

Re Section 29. Meter tubes and adjacent piping

First paragraph:

Fulfilling the requirement in litra a) presumes the installation of parallel meter tubes if the flow rate is too high for a single meter tube.

Fulfilling the requirement in litra b) can include the installation of parallel meter tubes if it is impractical to shut down the measuring system, and if frequent internal inspection and cleaning of meter tubes is necessary. Parallel meter tubes are not required in measuring systems for flare gas, and it is acceptable to plan to use replacement data for missing measurement data during maintenance periods. A bypass can be installed in measuring systems for fuel gas to ensure access for maintenance during operations. It can be planned for use of replacement data during periods where the bypass is in use for maintenance work on meter tubes. Meter tubes with two meters in series can be used instead of a bypass in measuring systems for fuel gas.

Fulfilment of the requirement in litra c) presumes a measuring system where parallel measuring tubes are connected by a common header which ensures the most uniform conditions throughout the measuring system. As regards fluids with particles (foreign objects), filters may be necessary upstream of the meter tube. To minimise installation effects, pipe components, including valves and thermowells, should be installed so that they disturb measurements as little as possible.

Third paragraph:

As regards measuring systems that do not have a backup meter tube, the meter tube should be equipped such that a failure in a single part does not harm the operation of the measuring system as a unit.

Meter tubes with two meters in series should be designed and installed such that the risk of a disturbance yielding the same error on both meters is minimised.

Re Section 30. Bypassing the measuring system

Second paragraph:

The measuring system should include interlocking to prevent unintended flow of petroleum in the bypass.

Re Section 31. Measurement of temperature and pressure

Appendix 2 refers to documents that could be relevant for fulfilling requirements for measuring temperature and pressure.

Third paragraph:

Fulfilling requirements in the third paragraph presumes that

a) instrument pipes that connect the meter tube's pressure tap with the sensor are as short as possible,
b) sensors for gas measurement and LNG measurement are placed higher than the pressure tap, and that the instrument pipes have a continuous downward slope towards the pressure tap,
c) sensors for oil measurement and multiphase measurement are placed lower than the pressure tap, and that the instrument pipes have a continuous upward slope toward the pressure tap. As regards pressure exceeding 500 kPa, sensors can be placed in the same manner as for gas measurement indicated in litra b).

Re Section 32. Protection

First paragraph:

Transmitters that are installed in places exposed to significant temperature fluctuations should be installed in a temperature-controlled environment or cabinet.

Fulfilling requirements for protection against disturbances caused by weather conditions presumes that the meter tube is equipped with a necessary amount of thermal insulation. As regards multiphase meters, thermal insulation may be necessary in order to reduce functional and performance problems associated with the formation and deposition of solids precipitated from the fluid.

Re Section 33. Monitoring and control

Third paragraph:

Valves that are particularly important for proving results (four-way valve and shut-off valves) should have automatic leak monitoring.

Re Section 34. Electronics

"Electronics" means signal processing units in electronic meters and transducers/ transmitters that transmit measurement data and other information to the measuring system's computer system. Appendix 2 refers to documents that could be relevant for fulfilling requirements for electronics.

First paragraph:

The use of pulsed data from meters is an established practice and ensures traceability to calibration laboratories, since the calibration laboratories generally use pulses as the input signal from meters.

Re Section 35. Computer system

"Computer system" means systems for general management, control, data acquisition and calculations (DCS, SCADA, Flow Computers).

Appendix 2 refers to documents that could be relevant for fulfilling requirements for computer systems.

Fourth paragraph:

In order to fulfil the audit trail requirement, the audit trail should e.g. include sufficient data and information to verify hourly and daily quantities.

Fifth paragraph:

Fulfilling requirements to protect data against loss and manipulation presumes securing data in the event of power outages and securing that everyone who has access to the computer system is identifiable and responsible (authorised).

Re Chapter 8. Special requirements for measuring systems for dynamic measurement of oil

The special requirements in Chapter 8 must be viewed in context with measurement requirements in Chapter 4 and general requirements for measuring systems in Chapter 7.

Re Section 36. Components of the oil measuring system

Appendix 2 refers to documents that could be relevant for fulfilling requirements for components of the oil measuring system.

Re Section 37. Calibration methods for oil meters

Appendix 2 refers to documents that could be relevant for fulfilling requirements for calibration methods for oil meters.

It follows from API MPMS 4.5 that a calibration method based on a master meter prover results in significantly higher uncertainty than a calibration method that includes a displacement prover.

Re Section 38. Oil meter

Appendix 2 refers to documents that could be relevant for fulfilling requirements for oil meters. The performance requirements in Table 4 are explained in more detail in Appendix 3.

Re Section 39. Displacement prover

Appendix 2 refers to documents that could be relevant for fulfilling requirements for displacement provers.

Repeatability must be understood as a range of variation determined by the equation (cf. e.g. API MPMS 12.2.4 – 5):

$$Repeatability\ \% = [(Max - Min)/Min] \cdot 100$$

Re Section 40. Master meter prover

Appendix 2 refers to documents that could be relevant for fulfilling requirements for master meter provers. The performance requirements in Table 6 are explained in more detail in Appendix 3.

Re Section 41. Measuring instruments connected to the oil measuring system

Appendix 2 refers to documents that could be relevant for fulfilling requirements for measuring instruments connected to the oil measuring system.

The requirements in Table 7 apply for measurement values read in the measuring system's computer system.

Re Section 42. Sampling equipment

Appendix 2 refers to documents that could be relevant for fulfilling requirements for sampling equipment (equipment used to extract samples from oil flowing through pipes).

Re Section 43. Algorithms and equations

Appendix 2 refers to documents that could be relevant for fulfilling requirements for algorithms and equations for use in oil measuring systems.

Re Chapter 9. Special requirements for measuring systems for dynamic measurement of gas

The special requirements in Chapter 9 must be viewed in context with general measurement requirements in Chapter 4 and general requirements for measuring systems in Chapter 7.

Re Section 44. Components of the gas measuring system

Appendix 2 refers to documents that could be relevant for fulfilling requirements for components of the gas measuring system.

Re Section 45. Calibration methods for gas meters

<u>Second paragraph:</u>

A theoretical prediction procedure can include static tests and geometric measurements, depending on technology.

As regards an ultrasonic flare gas meter, a procedure that includes metrologically traceable and sufficiently accurate measurements of geometric parameters, including:

- distances between transducers,
- average internal diameter of meter tube,
- cross-sectional area of meter tube,

as well as measuring time delays under zero-flow conditions, will fulfil requirements for a theoretical prediction procedure.

As regards an orifice plate-type differential pressure meter, the primary element consists of an orifice plate, orifice plate holder, differential pressure taps and meter tubes. A procedure that documents compliance with requirements in standards (e.g. ISO 5167) for the primary element's construction and geometric parameters will fulfil requirements for a theoretical prediction procedure.

Re Section 46. Gas meter

Appendix 2 refers to documents that could be relevant for fulfilling requirements for gas meters. The performance requirements in Table 9 are explained in more detail in Appendix 3.

Re Section 47. Measuring instruments associated with gas measuring system

Appendix 2 refers to documents that could be relevant for fulfilling requirements for measuring instruments connected to the gas measuring system.

The requirements in Table 10 apply for values from measuring instruments read in the measuring system's computer system.

Re Section 48. Online gas chromatograph

Appendix 2 refers to documents that could be relevant for fulfilling requirements for online gas chromatographs.

First paragraph:

As regards verification and calibration of an online gas chromatograph, acceptance limits for the individual gas component's molar fraction should be determined by dividing the uncertainty limit of the measured molar mass (cf. Table 12) by the square root of the number of gas components.

Assessment of compliance with acceptance limits for molar fraction and with the uncertainty limit for calorific value (cf. Table 12), normalised values should be used to reduce the weather's influence on the analysis results. Deviations for each individual gas component's molar fraction should not result in a deviation of more than 0.1% in calorific value or standard density.

Re Section 49. Sampling equipment

Appendix 2 refers to documents that could be relevant for fulfilling requirements for sampling equipment (equipment used to extract samples from gas flowing through pipes).

Re Section 50. Algorithms and equations

Appendix 2 refers to documents that could be relevant for fulfilling requirements for algorithms and equations for use in gas measuring systems.

Re Chapter 10. Special requirements for measuring systems for dynamic measurement of multiphase petroleum

The special requirements in Chapter 10 must be viewed in context with general measurement requirements in Chapter 4 and general requirements for measuring systems in Chapter 7.

Re Section 51. Components of the multiphase measuring system

Appendix 2 refers to documents that could be relevant for fulfilling requirements for components of the multiphase measuring system.

Re Section 52. Calibration methods for multiphase meters

Appendix 2 refers to documents that could be relevant for fulfilling requirements for calibration methods for multiphase meters.

Re Section 53. Multiphase meter

Appendix 2 refers to documents that could be relevant for fulfilling requirements for multiphase meters.

Re Section 54. Separator measuring system

No comment.

Re Section 55. Algorithms and equations

Appendix 2 refers to documents that could be relevant for fulfilling requirements for algorithms and equations for use in multiphase measuring systems.

Re Chapter 11. Special requirements for measuring systems and measurement of LNG

The requirements in Chapter 11 apply for measuring systems intended for static measurement of quantities (volume, mass and energy) of LNG. These requirements must be viewed in context with measurement requirements in Chapter 4.

Re Section 56. General requirements for measurement of LNG

Appendix 2 refers to documents that could be relevant for fulfilling general requirements for LNG measurement.

Re Section 57. Static measurement of volume and mass

Appendix 2 refers to documents that could be relevant for fulfilling requirements for static measurement of volume and mass.

Re Section 58. Sampling equipment

Appendix 2 refers to documents that could be relevant for fulfilling requirements for sampling equipment (equipment used to extract samples from LNG flowing through pipes).

Re Section 59. Gas chromatography

No comment.

Re Section 60. Density and calorific value

Appendix 2 refers to documents that could be relevant for fulfilling requirements for calculating the density and calorific value from the LNG composition.

Samples collected during the loading of LNG to ships may, if they are representative for LNG loaded to tank trucks, be used to calculate the density and calorific value of LNG loaded to tank trucks.

Re Section 61. Measurement of the energy of displaced gas and consumed gas

Appendix 2 refers to documents that could be relevant for fulfilling requirements for measuring the energy of displaced gas and consumed gas.

Re Chapter 12. Requirements for verification and calibration before a measuring system is used

The requirements in Chapter 12 apply for all measuring systems regulated by these Regulations. The requirements must be viewed in context with requirements in Chapters 2, 3, 4, and 7, and depending on the type of measuring system, with requirements in Chapters 8, 9, 10 or 11.

Re Section 62. Preconditions for using measuring instruments and measuring systems

No comment.

Re Section 63. Plans and procedures for verifications and calibrations

No comment.

Re Section 64. Calibration and adjustment of measuring instruments

Third paragraph:

In many contexts, an instrumental bias that exceeds one-third of the maximum permissible error of measurement can be significant.

Re Section 65. Use of laboratories for calibration

Accredited laboratory means a laboratory (stationary laboratory or field laboratory) that is accredited in accordance with the ISO/IEC 17025 standard for the relevant calibration methods. Documented compliance with relevant parts of ISO/IEC 9001 can fulfil the requirement for a non-accredited laboratory.

Re Section 66. Measurement standards

The documentation requirement can be fulfilled by presenting a calibration certificate. The requirement in the second sentence concerning measurement uncertainty is explained in more detail in Appendix 3. Requirements for measurement standards apply regardless of whether it is handled by an accredited or non-accredited laboratory.

Re Section 67. Flow calibration of oil meters

Appendix 2 refers to documents that could be relevant for fulfilling requirements for flow calibration of oil meters. The performance requirements in Section 38 are explained in more detail in Appendix 3.

<u>First paragraph:</u>

The requirement for measurement points on the calibration curve is a minimum. Additional measurement points may be necessary to simultaneously fulfil requirements in Section 64.

<u>Fourth paragraph:</u>

Fulfilling the requirement in the fourth paragraph includes the collection of diagnostic data during the calibration for meters that can produce such data.

Re Section 68. Calibration of displacement prover

Appendix 2 refers to documents that could be relevant for fulfilling requirements for calibration of displacement provers.

<u>Second paragraph:</u>

Proving should be tested using all base volumes.

Re Section 69. Flow calibration of master meters

Appendix 2 refers to documents that could be relevant for fulfilling requirements for flow calibration of master meters. The performance requirements in Section 40 are explained in more detail in Appendix 3.

Re Section 70. Flow calibration of gas meters

Appendix 2 refers to documents that could be relevant for fulfilling requirements for flow calibration of gas meters. The performance requirements in Section 46 are explained in more detail in Appendix 3.

<u>First paragraph:</u>

The requirement for the number of calibration points on the calibration curve is a minimum. Additional measurement points may be necessary to simultaneously fulfil requirements in Section 64.

<u>Fourth paragraph:</u>

Fulfilling the requirement in the fourth paragraph presumes the collection of diagnostic data during the calibration for meters that can produce such data.

Re Section 71. Flow calibration of multiphase meters

No comment.

Re Section 72. Calibration and verification of associated measuring instruments

Appendix 2 refers to documents that could be relevant for fulfilling requirements for calibration and verification of associated measuring instruments.

Re Section 73. Verification of gas chromatographs

Appendix 2 refers to documents that could be relevant for fulfilling requirements for verification of gas chromatographs.

Re Section 74. Verification of sampling equipment

Appendix 2 refers to documents that could be relevant for fulfilling requirements for verification of sampling equipment.

Re Section 75. Measurement and control of physical constants

No comment.

Re Section 76. Verification of computer systems

Appendix 2 refers to documents that could be relevant for fulfilling requirements for verification of computer systems.

Re Section 77. Testing of assembled measuring systems and automatic sampling systems

Appendix 2 refers to documents that could be relevant for fulfilling requirements for testing of assembled measuring systems and automatic sampling systems.

Re Chapter 13. Requirements for operation and maintenance of measuring systems

The requirements in Chapter 13 apply for the operation and maintenance of measuring systems regulated by these Regulations. The requirements must be viewed in context with requirements in all previous chapters.

Operating a measuring system means tasks and routines that are necessary in order for a measuring system to function as planned. Operating a measuring system includes use, supervision and control, preparedness in the event of malfunctions, etc.

Maintenance means all measures, technical and administrative, to maintain a measuring system at an established level of quality. This maintenance comprises:

1) Corrective maintenance, a category of maintenance which, through repairs, inspections or replacement, restores the function of a damaged or defective measuring system to function within defined acceptance criteria.
2) Preventive maintenance, measures to detect, prevent or reduce damage to measuring systems in order to maintain or extend the lifetime by controlling wear and tear and faults at an acceptable level. Preventive maintenance includes:

a) Periodic maintenance, a category of preventive maintenance of a measuring system where replacement, monitoring or testing is conducted at predetermined intervals; calendar time, operating time or number of cycles.
b) Condition-based maintenance, a category of preventive maintenance of a measuring system that uses sensor data and diagnostics to determine the measuring system's current condition and to determine the type and schedule of maintenance. (The goal of this approach, or type of maintenance, is to use the data collected during monitoring to ensure that maintenance is carried out at the right time and before a critical fault occurs.)
c) Predictive maintenance, a category of preventive maintenance that uses sensor data, diagnostics, aggregate sensor data and long-term tendencies (trends) to predict future wear and tear and faults in a measuring system and to determine the type and schedule of maintenance. (The goal of this approach is to plan maintenance on a future date when it is more practical and will have a minimal impact on production.)

The Norwegian Offshore Directorate expects licensees, in their choice of maintenance system, to take into consideration the risk of failing to fulfil requirements in these Regulations (cf. Section 5 second paragraph/guideline for Section 5 second paragraph).

Re Section 78. General requirements for operation and maintenance

First paragraph:

Fulfilling the requirement to operate measuring instruments and measuring systems as planned presumes that they are operated in accordance with their defined working range and under their designated rated operating conditions.

Third paragraph:

It is the licensee's responsibility to define what is a reasonable timeframe for repairs and replacements. Timeframes will usually depend on multiple factors, including the equipment's criticality for the measurement and measurement type.

Re Section 79. Maintenance programme

First paragraph:

The maintenance programme should include sub-programmes for
- verifying metrological characteristics between calibrations,
- inspecting the measuring instruments' diagnostic parameters,
- comparing measurement data with data collected through calibration,
- inspections,
- testing,
- preventive maintenance, etc.

Second paragraph:

Charts (schematic representation of the relationship between quantities or the development of a quantity) should be used to monitor the long-term trends of parameters that are important for the measurement result, such as the meters' calibration factors, the gas chromatographs' response and retention factors, etc.

Re Section 80. Calibration programme

Several factors can be relevant to consider in the establishment and maintenance of calibration programmes, including:

- uncertainty limits of relevant measurands,
- risk of the measuring instrument in use deviating from requirements for the maximum permissible error of measurement and instrumental measurement uncertainty,
- risk of financial loss as a result of the measuring instrument not functioning in an appropriate manner over a long period of time,
- type of instrument,
- instrumental operation and stability,
- manufacturer's recommendations,
- calibration history,
- maintenance history (preventive and corrective maintenance),
- frequency and quality of controls between calibrations,
- risk during transport,
- calibration cost versus financial risk at longer intervals.

Measuring instruments should normally be recalibrated in their "as found" condition so that any shift in performance (instrumental drift and stability) from previous calibrations can be quantified.

Re Section 81. Working standards

First paragraph:

The requirement regarding the working standard's accuracy is explained in more detail in Appendix 3.

Re Section 82. Evaluation of measurement data during verification

Appendix 2 refers to documents that could be relevant for fulfilling requirements for evaluating measurement data during verification.

Evaluation of measurement data during the measurement of fluid flows is explained in more detail in Appendix 3. The general principles stated in the Appendix are also valid for other measurements, including the measurement of temperature, pressure and density.

Re Section 83. Operation and maintenance of oil meters

Appendix 2 refers to documents that could be relevant for fulfilling requirements for operation and maintenance of oil meters.

Second paragraph, litra b):

Acceptable and commonly used limits for reproducibility are 0.15% or a three-standard deviation limit (see guideline for the fourth paragraph).

Third paragraph:

A condition-based or predictive maintenance system can ensure that requirements for instrumental measurement uncertainty are fulfilled if the system takes the following into account:

- probability of corrosion, erosion and deposits in meter tubes and on sensors (transducers),
- likelihood of revealing corrosion, erosion and deposits in meter tubes and on sensors (transducers),
- probability of changed fluid properties, including changes in viscosity.

As regards meter tubes with two meters in series, the acceptance limits for deviations in indications should comply with requirements in Section 82 Evaluation of measurement errors (cf. guideline for Section 82).

<u>Fourth paragraph:</u>

A control chart should be evaluated regularly so that a trend in one direction can be detected and acted upon early. The control chart can have a fixed deviation limit. A commonly used limit is 0.15%. If operating conditions are stable, statistical methods can be used to evaluate the reproducibility of calibration factors. For such methods, it is common to compare a new calibration factor with a three-standard deviation limit based on previously determined calibration factors.

Re Section 84. Operation and maintenance of provers

Appendix 2 refers to documents that could be relevant for fulfilling requirements for operation and maintenance of provers.

<u>Fourth paragraph:</u>

Fulfilling requirements for documentation of unreasonably high costs presumes an assessment of the calibration cost against the financial risk of longer calibration intervals. Financial risk will, among other things be determined by the financial value of the oil (quantity and quality) being measured.

In order to substantiate that requirements for the base volume's uncertainty will be fulfilled with longer calibration intervals, the documentation should include an assessment of:

1. calibration history,
2. the likelihood of
   a) wear and tear or damage to displacement media (ball or piston rings)
   b) worn or defective detector switches,
   c) wear and tear and damage to interior coatings,
   d) build-up of foreign matter.

If the base volume of the displacement prover at calibration deviates by more than ± 0.04% from the volume in previous calibrations, troubleshooting should be undertaken to reveal the cause of the deviation. The calibration interval must be reduced following such a calibration result (cf. Section 80).

Re Section 85. Operation and maintenance of gas meters

<u>Second paragraph:</u>

A condition-based or predictive maintenance system can ensure that requirements for instrumental measurement uncertainty are fulfilled if the system takes the following into account:

- probability of corrosion, erosion and deposits in meter tubes and on sensors (transducers),

- likelihood of revealing corrosion, erosion and deposits in meter tubes and on sensors (transducers),
- probability of changed fluid properties, including changes in density.

As regards meter tubes with two meters in series, the acceptance limits for deviations in indications should comply with requirements in Section 82 Evaluation of measurement errors (cf. guideline for Section 82).

Third paragraph:

The metrological characteristics of flare gas meters at zero flow should be verified. Verification of metrological characteristics under dynamic conditions can replace or supplement verification at zero flow.

Fourth paragraph:

The meter’s sensitivity to the meter tube's internal condition and the fluid's characteristics should be taken into consideration in the stipulation of inspection intervals.

As regards meter tubes with an orifice plate, an internal inspection includes an inspection of the meter tube's internal surface, orifice plate and pressure taps. Orifice plates in delivery measuring systems and CO_2 tax measuring systems should be inspected at least annually.

Re Section 86. Operation and maintenance of multiphase meters

No comment.

Re Section 87. Operation and maintenance of associated measuring instruments

No comment.

Re Section 88. Operation and maintenance of online gas chromatographs

Appendix 2 refers to documents that could be relevant for fulfilling requirements for operation and maintenance of online gas chromatographs.

Re Section 89. Operation and maintenance of samplers

The performance of a sampler should be verified as soon as possible once it is installed and put to use.

Second paragraph:

A representative sample, as defined by these Regulations, is an ideal. An acceptable sample is a sample that, with a certain likelihood (in this case, a 95 per cent confidence level) can be said to be representative for the composition in the quantity from which the sample was taken.

It follows from ISO 3171:1998 (see Appendix 2) that the following must be true in order for an oil sample to be acceptable:

a) the automatic sampler's performance factor is between 0.9 and 1.1,
b) the sampling is flow-proportional,
c) there have been no interruptions in the sampling that could affect the performance factor beyond the limits in a).

The performance factor in a) is the ratio between the accumulated sample volume and the calculated sample volume.

Re Section 90. Operation and maintenance of computer systems

Third paragraph:

An unambiguous audit trail presumes that an account is kept of changes in software. This can be done by logging the software version numbers and checksums.

Re Chapter 14. Requirements for materials and information

Re Section 91. General requirements for materials and information

This requirement must be viewed in context with the general rule in Section 10-4 of the Petroleum Act relating to materials and information and Section 55 of the Petroleum Regulations relating to safekeeping duty. The obligation pursuant to Section 10-4 of the Petroleum Act entails that documentation concerning fiscal measurement as referenced in these Regulations shall be available in Norway regardless of where the operating organisation is located. This does not mean a prohibition against storing the documentation abroad, as long as it can be made available to the Norwegian Offshore Directorate within a reasonable timeframe. In certain instances, e.g. during audits at measuring stations located abroad, it will be most practical for the Norwegian Offshore Directorate to have access to the documentation on site. At operating organisations located outside Norway, the documentation should be available at the place of use and available to the Norwegian Offshore Directorate upon request.

Re Section 92. Information prior to BOV

Prior to a Decision to Continue (BOV), the licensee shall inform the Norwegian Offshore Directorate of its measurement concept. This means information about:

a) measurands,
b) measurement uncertainty,
c) technical solutions,
d) operation and maintenance, and
e) financial aspects (cost-benefit assessment).

Measurement concept means a plan that forms the basis for designing a measuring system.

Re Section 93. Information about measurement in PDOs and PIOs

PDOs and PIOs must, to a necessary extent, contain information about the measurement concept and any deviations from provisions in these Regulations. This means information about the following:

a) measurands,
b) measurement uncertainty,
c) technical solutions,
d) operation and maintenance,
e) financial aspects (cost-benefit assessment), and
f) any deviations from these Regulations, including which provisions these deviations are linked to and substantiations for the deviations.

If a PDO or PIO is approved, this means that the measurement concept and any deviations from these Regulations have been approved. Potential exemptions will only apply for the deviations from the regulatory requirements that are not identified in the PDO or PIO. An exemption will signify the authorities' decision to accept a deviation from regulatory requirements.

Reference is otherwise made to "Guidelines for plans for development and operation of a petroleum deposit (PDOs) and plans for installation and operation of facilities for utilisation of petroleum (PIOs)".

Re Section 94. Applications for consent for start-up and continuation of measuring systems

An application for consent pursuant to the second paragraph shall contain information demonstrating that the measuring system complies with these regulatory requirements. This entails the following content in the application:

a) specification of measurands and uncertainty limits,
b) description of the measuring system,
c) pipe and instrument diagram,
d) overview of standards the measuring system (construction, installation, operation and maintenance) must comply with,
e) signed factory acceptance test reports (FATs),
f) calibration certificates,
g) an uncertainty budget,
h) procedures for calibrations and verifications that must be conducted to prepare the measuring system for use, and
i) procedures for operation and maintenance.

Re Section 95. Information about measurement in the annual status report

The Guidelines for annual status reports for fields in production provide a more detailed description of the information that must be included in an annual status report. These Guidelines are available on the Norwegian Offshore Directorate's website: https://www.sodir.no/en/regulations/guidelines/.

Re Section 96. Uncertainty budget for CO_2 tax measurements

Section 15 and the guideline for Section 15 provide a description of how to fulfil the requirement in Section 96 for the uncertainty budget.

It follows from Section 15 that the compliance with uncertainty limits for values associated with measurement quantities in Section 10 shall be demonstrated by an uncertainty budget. As regards CO_2 tax measurements, this applies for the accumulated volumes in Table 2 in the Regulations. The guideline for Section 15 provides examples of resulting measurement models and associated uncertainty models. Reference is made to NFOGM's handbooks and uncertainty programmes for measurement models and associated uncertainty models for flow measurements (input quantities in resulting measurement models). The guideline for Section 28 provides a simplified measurement model and uncertainty model for measuring the flow of gas to the flare and cold-venting system. One example of an uncertainty budget for the quantity of flared petroleum is provided in Example 2 in the guideline for Section 15.

Appendix 4 can be used to fulfill requirements for the uncertainty budget.

Re Section 97. Other information

First paragraph:

The Norwegian Offshore Directorate will normally respond to information about faults that can provide a basis for major corrections of measured quantities of oil and gas within ten (10) business days.

Second paragraph:

"Information about cargoes" means cargo papers that document the quantity and quality of oil and other petroleum products, including methane, ethane and ethanol delivered to (loaded on board) ships.

Re Chapter 15. General provisions

Re Section 98. Supervisory authority – authority to make individual administrative decisions, etc.

The Ministry of Energy is the appellate body for decisions made by the Norwegian Offshore Directorate pursuant to these Regulations.

Re Section 99. Exemption

Applications for exemptions should normally contain the following:

a) an overview of the provisions from which an exemption is sought,
b) an explanation of the particular cases that make an exemption necessary or reasonable,
c) an explanation of how the exemption issue has been processed internally in the enterprise,
d) a description of the deviation and its planned duration,
e) a description of potential measures that will compensate for the deviation in whole or in part, and
f) a description of potential measures to correct the deviation, if the deviation is of a temporary nature.

Re Section 100. Penal provision

No comment.

Re Section 101. Entry into force and transitional provisions

No comment.

Appendix 1. Metrological glossary

A metrological glossary of terms and expressions used in the Regulations and Guidelines can be found at sodir.no.

Appendix 2. Standards and other recognised documents

Standards and other recognised documents are organised in a spreadsheet. The spreadsheet can be found at sodir.no.

Appendix 3. Evaluating measurement data in connection with measuring fluid flow

This appendix concerns evaluating measurement data in connection with measuring fluid flow, including uncertainty, through calibration and verification. The document can be found at sodir.no.

Appendix 4. Uncertainty budget for CO_2 tax measurements

This appendix is a spreadsheet that can be used to send the Norwegian Offshore Directorate an uncertainty budget for CO_2 tax measurements in accordance with section 96.