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# Update of Norwegian Regulations for Fiscal Measurement

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## 1 INTRODUCTION

The Norwegian Petroleum Directorate, celebrated its 40 years anniversary this year. The work to develop a Measurement regulation started some years after the start up. A number of drafts were in use during the late 70ties and until the first official Regulations were put in force from 2. April 1984.

Thereafter the Norwegian Fiscal Measurement Regulations have been updated several times. We have the legal possibility to do updates every year, but every three years have been a more realistic target.

Normally the updates are fairly small, but sometimes also larger modifications take place. The 2001, update was a major one and also the update this year (2012) is fairly extensive.

## 2 THE 2012 REGULATORY UPDATE

The proposed changes were approved for by the Ministry and then sent for comments to the industry during 2011. A lot of constructive comments were received and we tried to implement as best we could. The Regulations were then sent for a final approval by the Petroleum Ministry.

The document was finally approved 8th March 2012, and the entry into force date was set to 1st July 2012.

## 3 AREAS WERE CHANGES HAVE BEEN IMPLEMENTED

The Regulations and the document for the comments to the various sections are attached after this point. The new text is marked with yellow colour. The English text document can be found on the web page: NPD.no
The Norwegian text document can be found on the web page: Lovdata.no

# REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF $CO_2$-TAX (THE MEASUREMENT REGULATIONS)

1 November 2001

The Norwegian Petroleum Directorate (NPD)

**CONTENTS**

# PREFACE

The purpose of these regulations is to ensure that accurate measurements form the basis of the calculation of taxes, royalties and fees etc. to the Norwegian state, including the $CO_2$ tax, and the income of the licensees. The regulations contain supplementary provisions to the requirements of the Petroleum Act and the $CO_2$ Tax Act relating to measurement of petroleum and stipulate framework requirements concerning the organisation, planning and implementation of the activity as referred to in the Petroleum Act and the $CO_2$ Tax Act. Put into force 30 October 2006, the requirements for measuring systems for liquids other than water are changed to be in conformance with the Directive 2004/22/EU, Measuring Instruments Directive (MID) and are harmonized with the Regulation of 21 December 2007 no. 1738, "Requirements for measuring systems for liquids other than water" adopted by Department for Industry and Trade (NHD) and Norwegian Metrology Service cf. remarks to Section 13a. Practically this applies to measuring systems for Liquid Petroleum and NGL.

The measurement regulations define functional and specific requirements to the design and operation of the metering equipment, elaborates on the responsibility of the individual participant to comply with requirements laid down in or pursuant to applicable law and shall contribute to ensuring that the metering equipment and method at all times comply with the requirements of these regulations relating to accumulated measuring uncertainty. The regulations stipulate requirements with regard to how the quantities of fuel and flare gas are to be reported and documented. Furthermore the regulations provide for suitable supervision of the activities. These regulations replace the previous Regulations for fiscal measurement of oil and gas etc. and the previous Regulations relating to measurement of fuel and flare gas for calculation of $CO_2$ tax in the petroleum activities. Particular points relating to $CO_2$ tax measurement are dealt with in comments re. Section 14. If provisions contained in these regulations apply to either fuel gas or flare gas this will appear from the text.

The comments to Section 1 of these Regulations describe the process concerning equipment and methods for measuring $NO_x$ emissions.

The regulations provide for a practice whereby not all documentation needs to be submitted to the Norwegian Petroleum Directorate, but may instead be available from the operator and be submitted to the Norwegian Petroleum Directorate on request. Furthermore provision is made for transfer of information electronically.

Comments have been prepared to the individual provisions of these regulations. The comments provide explanation and guidance in relation to the provisions of the regulations. Examples are given to show how the requirements of regulations can be complied with, or reference is made to recognised standards, including industry standards, as one way in which the requirements of the authorities may be complied with. Standards which are not mentioned in the Regulations including comments may be applied following consultation with the Norwegian Petroleum Directorate. Trading in petroleum takes place across national borders with international actors. Technical standards should therefore be internationally accepted. Reference is further made to comments re. Section 4. Guidelines to Plan for development and operation of a petroleum deposit, PDO, and Plan for installation and operation of facilities for transport and utilisation of petroleum, PIO, of 18 May 2000 contain details on the information which should be contained in a PDO/PIO with regard to fiscal measurement systems.

# REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF $CO_2$ TAX (THE MEASUREMENT REGULATIONS)

**Regulations relating to measurement of petroleum for fiscal purposes and for calculation of $CO_2$ tax, issued by the Norwegian Petroleum Directorate 1 November 2001 pursuant to Section 86 of Regulations to Act relating to petroleum activities issued by Royal Decree 27 June 1997 No. 653, cf. Act of 29 November 1996 No. 72 relating to petroleum activities, Section 4-10 and Section 5 of Act of 21 December 1990 No.72 relating to tax on discharge of $CO_2$ in connection with petroleum activities on the continental shelf, cf. Decision on delegation issued by the Ministry of Petroleum and Energy 28 June 1985 and 27 December 1990. Regulations of 11 December 2001 nr. 1451 on Excise Duties ($NO_x$ duties) section 3-19-7. EEA Agreement, Annex II, Chapter IX, paragraph 27b (Directive 2004/22/EF). Last amended 8 March 2012.**

## CHAPTER 1
## INTRODUCTORY PROVISIONS

### Section 1
### Scope

These regulations are applicable to the petroleum activities in areas comprised by Section 1-4 of the Act of 29 November 1996 No. 72 relating to petroleum activities and Section 2 of the Act of 21 December 1990 No. 72 relating to tax on discharge of $CO_2$ in connection with petroleum activities on the continental shelf, specifically:

a) in planning, design, construction and operation of metering systems for measuring produced, transported and sold quantities of oil and gas (fiscal measurement systems)
b) in planning, design, construction and operation of metering systems and metering equipment for determination and reporting of quantities used for fuel and flare gas in petroleum activities.

For flow meters for liquids other than water the Regulation of 26 April 2006 no. 466 concerning requirements (for liquids other than water) issued by Department of Industry and Trade (NHD) and Norwegian Metrology Service, with the clarifications pursuant to this regulation, is prevailing.

### Section 2
### Definitions

For the purpose of these regulations, the following definitions shall apply:

*Accreditation:*
An official recognition to the effect that an organisation is operating in accordance with a documented quality assurance system and that it has demonstrated is competency to carry out specified tasks.

*Allocation:*
Apportionment of petroleum between various owner groups and owner companies.

*Recognised standard:*

Standards, guidelines and similar which within a technical sphere are internationally and/or nationally recognised. Acts or regulations which are not directly applicable but which regulate corresponding or neighbouring areas may equally be recognized standard.

*Fuel:*
Natural gas, oil, condensate or diesel used for operation of combustion machinery such as turbines and similar.

*Place of operation:*
Facility or terminal where the metering system is in service.

*Place of manufacture:*
Place where fabrication, assembly and testing of one or more of the metering system's main components takes place.

*Computer part:*
That part of the metering system which consists of computers and receives metering signals from A/D converters or from digital instrument loops.

*Flare gas:*
Natural gas burnt off or vented to the atmosphere.

*Fiscal metering:*
Metering carried out in connection with purchase and sale and the calculation of taxes and royalties.

*Sensing element:*
A device that responds to the condition which is to be measured, so that the device produces a signal proportional to this condition.

*Flow meter for liquids other than water:*
An instrument for continuous measurement, registration and display of the amount of liquid which flows in a liquid filled pipe under defined conditions.

*Instrument:*
An assembly consisting of a transducer and one or more sensing elements. The signal from an instrument represents a physical condition.
A technical device used to measure a physical parameter.

*Instrument part:*
Part of the metering system from and including the instrument to the digital input of the computer part.

*Calibration:*
Establishment of relationship between measured value and reference value with known uncertainty. The English term "proving" is often used for calibrating meters against a known volume.

*Calibration factor, K-factor:*
Relationship between the measured value coming from a meter and the measured value from a reference measurement system. (Normally a designated value that signifies pulses per volume unit).

*Calibration factor (meter factor) for flow meter:*
Non designated value which states the relationship between the flowmeter's registration and the flow volume.

*Calibration mode:*
Selectable condition of the computer part to carry out verification whilst the associated meter tubes are closed.

*Control:*
Monitoring, supervision, inspection and similar of conditions, processes, products etc. to ensure that they comply with specifications.

*Linearity:*
1) Deviation between a calibration curve for a device and a straight line.
2) Correlation between variables where a change in one causes a precise and proportional change for the other.

*Liquefied Natural Gas (LNG):*
Natural gas mainly consisting of methane ($CH4$) refrigerated to liquefied form at about minus 160 degrees C, with density at atmospheric pressure of around 430 – 460 $kg/m^3$. Standard density is typically in the area 0,67 – 0,74 $kg/Sm^3$.

*Mechanical part:*
All mechanical equipment included in an oil or gas metering system.

*Meter tube:*
Straight pipe section where a flow meter is installed.

*Instrument loop:*
Assembly of all equipment and computer links etc. from sensor input to the visual representation in the computer part.

*Metering station:*
Assembly of metering equipment dedicated to the determination of measured quantities.

*Measurement uncertainty:*
An expression of the result of a measured value which characterises the range within which true value is expected to lie.

*Metering system:*
Consists of a mechanical part, an instrument part and a computer part, as well as appurtenant documentation and procedures.

*Resolution:*
Indicates the least variation in signal level which produces a noticeable change in the displayed value.

*Petroleum products:*
Marketable products fractionated from crude oil or natural gas. Examples are: Ethane, propane, petrol, paraffin.

*Prover:*

Device for calibration of dynamic flow meter, based on displacement of a body through a calibrated tube.

*Conformity marking*
A marking of a flow meter with a "CE" mark, additional metrological marking and identification number for the relevant notified body as described in the Regulation for flow meters (for liquids other than water).

*Conformity declaration*
A declaration that a product fulfill the technical requirements which are issued for flow meters in the the Regulation for flow meters (for liquids other than water).

*Flow meter (Gas):*
Equipment located in or clamped to a pipe with associated signal transformer providing a primary signal proportional to the amount of flow through the pipe.

*Transducer:*
Technical device which changes the nature of the measured signal. Used in these regulations solely in respect of ultrasonic meters.

### Section 3
### Responsibility according to these regulations

The licensee and other parties participating in petroleum activities comprised by these regulations are responsible according to the regulations and individual administrative decisions issued by virtue of the regulations.

In addition the licensee has a duty to see to it that anyone carrying out work for him, either personally, by employees, contractors or sub-contractors, complies with these regulations and individual administrative decisions issued by virtue of the regulations.

### Section 4
### Requirements to the petroleum activities in general

Activities as mentioned in Section 1 of the present regulations shall be carried out in accordance with requirements stipulated by or pursuant to these regulations, and in accordance with recognised standards for such activities.

When technology or methods not described in recognised standards are used, criteria for development, testing and operation are required to be produced.

## CHAPTER II
## REQUIREMENTS RELATING TO MANAGEMENT CONTROL SYSTEM ETC.

### Section 5
### Management control system

The licensee and others participating in the petroleum activities shall establish, follow up and assure the development of a management control system which shall include organisation, processes, procedures and resources necessary to ensure compliance with the requirements of the present regulations.
A management control system for metering shall be prepared and maintained in a systematic and controlled manner. Update and revision shall be announced within the organisation itself, to the Norwegian Petroleum Directorate and other parties concerned. The management

control system shall ensure that relevant experience and information is conveyed from one shift of personnel to the next and from the construction phase to the operational phase.

Executive responsibility for, and supervision of, the management control system shall be placed with the unit responsible for the other management control systems of the enterprise.

A quality assurance manual for the operation of metering systems shall be prepared.

**Section 6**
**Organisation and competence**

The functional scope and areas of responsibility of personnel who carry out supervision of or tasks in connection with the metering system shall be documented in the organisation chart of the licensee. The duties, responsibilities and authority of the personnel shall be described.

The licensee shall nominate the person responsible for the metering system. The nominated person shall be responsible to see that procedures relating to operation, maintenance, calibration and control are followed.

All personnel carrying out tasks related to the metering systems shall possess documented qualifications within the relevant technical sphere. A system shall be established to show that updating and skills/competence advancement is ensured.

**Section 7**
**Verification**

When planning, designing, purchasing, building and operating fiscal measurement systems as mentioned in these regulations, the licensee shall be able to verify that the provisions of the regulations or individual administrative decisions have been complied with. Independent verification of critical parameters may be required.

The licensee shall see to verification of fiscal figures and calibration reports for equipment comprised by these regulations.

## CHAPTER III
## GENERAL REQUIREMENTS RELATING TO MEASURING AND THE MEASUREMENT SYSTEM

**Section 8**
**Allowable measurement uncertainty**

| Measurement system | Uncertainty limit at 95percent (%), confidence level *(expanded uncertainty with coverage factor k=2)* |
|---|---|
| Oil metering for sale and allocation purposes | 0,30 % of standard volume |
| Gas metering for sale and allocation purposes | 1,0 % of mass |
| Fuel gas metering | 1,5 % of standard volume |
| Flare gas metering | 5,0 % of standard volume |
| Sales measurement of LNG | 0,50 % of measured energy contents per ship load |

The measurement system shall be designed so that systematic measurement errors are avoided or compensated for.

It shall be possible to document the total uncertainty of the measurement system. An uncertainty analysis shall be prepared for the measurement system within a 95 percent confidence level. In the present regulations a confidence interval equal to ± 2 σ, i.e. coverage factor k=2, is used. This gives a confidence level slightly higher than 95 percent.

LNG shall be measured and analyzed at the place of loading. The operator is responsible for, and shall be able to document, that the measurement system is in accordance with recognized norms.

LNG volumes may be determined in connection with loading by use of traceable measured vessel tanks and calibrated level gauges.

In respect of the measurement system's individual components the following maximum limits apply:

| **Component** | ***Circuit uncertainty limits*** | ***Uncertainty limits component/ Linearity band*** | ***Repeatability limits (band)*** |
|---|---|---|---|
| Meter prover oil | NA | 0,04 % for all 4 volumes | 0,02 % for all 4 volumes |
| Turbine meter oil | 1 pulse of 100000, 0,001 %, during pulse transmission of the measurement signal. | 0,25 % in working range (10:1)<br>Band:<br>0,50 % (10:1) and 0,30 % (5:1) | 0,027 %, uncertainty, cf. Table B1, API MPMS Ch. 5.8. |
| Ultrasonic flow meter oil | 1 pulse of 100000, 0,001 %, at pulse transmission of signal | 0,20 % in working range (10:1)<br>Band:<br>0,30 % (10:1) | 0,027 %, uncertainty, cf. Table B1, API MPMS Ch. 5.8. |
| Coriolis meter oil | 1 pulse of 100000, 0,001 %, during pulse transmission of the measurement signal | 0,20 %, in the working range.<br>Band:<br>0,30 % (10:1) | 0,027 %, uncertainty, cf. Table B1, API MPMS Ch. 5.8. |
| Turbine meter gas (sales – allocation) | 1 pulse of 100000, 0,001%, during pulse transmission of the measurement signal | 0,70 % in working range (10:1)<br>Band:<br>1,0 % (10:1) | 0,28 % in working range (10:1) |

| **Component** | ***Circuit uncertainty limits*** | ***Uncertainty limits component/ Linearity band*** | ***Repeatability limits (band)*** |
|---|---|---|---|
| Ultrasonic flow meter gas (sales – allocation) | 1 pulse of 100000, 0,001 %, at pulse transmission of signal | 0,70 % in the working range (20:1) after performing zero point correction and entering K-factor. Deviation from reference, see NORSOK I-104. | 0,40 % in working range (20:1) after zero point control |

| **Component** | ***Circuit uncertainty limits*** | ***Uncertainty limits component/ Linearity band*** | ***Repeatability limits (band)*** |
|---|---|---|---|
| Coriolis gas meters (allocation) | 1 pulse of 100000, 0,001%, at pulse transmission of signal | 0,70% in the working range 20:1 | 0,40% for gas velocities exceeding the minimum specified velocity |
| Pressure measuring oil,gas | 0,30% of measured value in working range | 0,10% of measured value in working range | NA |
| Pressure measuring fuel gas, flare gas | 0,50% of measured value in working range | 0,20% of measured value in working range | NA |
| Temperature measuring oil and gas | 0,30˚C | 0,20˚C | NA |
| Temperature measuring fuel and flare gas | 0,50˚C | 0,30˚C | NA |
| Density measuring oil | 0,50 kg/m3 | 0,30 kg/m3 | NA |
| Density measuring gas | 0,30% of measured value | 0,20% of measured value | NA |
| Differential pressure measuring | 0,30% of measured value in working range | 0,10% of measured value in working range | NA |
| Water in oil measuring | | 0,05% volume % absolute for 0 to 1,0 volume % water content, ± 5% of measured value over 1,0 volume % water content | 0,50% of measured value at water content above 0,01% |
| Density measurement LNG | NA | 0,30% of measured value | NA |
| Volume measurement LNG | NA | 0,30% of measured value | NA |
| Online GC | NA | 0,30% of calorific value | 0-25 mol%: 0,02 %, 25-100 mol%: 0,05% |
| Calorific value gas | NA | 0,30% of calorific value | NA |
| Uncertainty computer part for oil and gas | NA | 0,001 % | NA |
| Uncertainty computer part for fuel and flare gas | NA | 0,1 % | NA |
| With regard to fuel gas: cf. comment re. Section 14. | | | |

The linearity band can be used as a test criterion when accepting meters and is stated in the component uncertainty column where this is relevant.

The repeatability requirement for fluid meters is now an uncertainty requirement of 0,027 %, cf. Table B1, in API MPMS Ch. 5.8.

**Section 8a**

**Allowable measurement uncertainty for measuring systems for liquids other than water**

For measuring systems for liquids other than water, cf. this Regulation section 13 a, the minimum requirements for uncertainty limits as included into the Regulation of 21 December 2007 no. 1738, section 29, cf. this Regulation section 3. The equivalent requirements apply to modules of a measuring system if pursuant to requirements stated in the Regulation concerning requirements for measuring systems for (liquids other than water).

**Section 9**

**Units of measurement**

The measuring system shall give readings in SI units. Reporting of fiscal figures to the Norwegian Petroleum Directorate shall be in SI units.

Reporting of fuel and flare gas to the Norwegian Petroleum Directorate shall be in standard cubic meters in respect of natural gas and litres in respect of diesel or other hydrocarbons in liquid phase.

Determination of the critical parameters of the measuring system by measurements shall be in SI units.

**Section 10**

**Reference conditions**

Standard reference conditions for pressure and temperature shall in measuring oil and gas be 101.325 kPa and 15 °C. In the measuring of petroleum products other reference pressure may be used.

**Section 11**

**Determination of energy content etc.**

Gas composition from continuous flow proportional gas chromatography or from automatic flow proportional sampling shall be used for determination of energy content.

With regard to sales gas metering stations two independent systems shall be installed.

When oil or gas is analysed to determine physical and/or chemical properties and the analysis results are used for sale or allocation purposes, this shall be carried out by a competent laboratory.

**Section 12**

**Bypassing the metering system**

Bypassing of the metering system is not permitted.

# CHAPTER IV
# REQUIREMENTS TO DESIGN OF THE METERING SYSTEM

## Section 13
## Requirements to the metering system in general

The measuring system shall be planned according to the requirements in this regulation and according to recognised standards for such measuring systems. Additional requirements following from Section 13a apply for flowmeters for liquids (other than water).

The metering system shall be capable of metering the full range of planned hydrocarbon flows without any component involved operating outside its working range.

The measurement system shall, to the extent possible, be equipped with duplicated instrument functions for signals from primary meters and instrumentation for facilitating condition based monitoring and reducing the need for preventive maintenance. Signals from parallel metering runs can be used in connection with condition monitoring.

Wireless communication between different parts of the fiscal measurement system can be used if it is demonstrated that the solutions are equal to or better than the traditional solutions using a communication cable, with regard to integrity.

On sales metering stations the number of parallel meter runs shall be such that the maximum flow of hydrocarbons can be measured with one meter run out of service, whilst the rest of the meter runs operate within their specified operating range.

The metering system shall be suitable for the relevant type of measuring, the given fluid properties and the hydrocarbon volumes to be measured.

If necessary, flow straighteners shall be installed.

In areas where inspection and calibration takes place there shall be adequate protection against the outside climate and vibration.

The metering tube and associated equipment shall be insulated upstream and downstream for a distance sufficient to prevent temperature changes affecting the instruments that provide input signals for the fiscal calculations.

Shutoff valves shall be of the block and bleed type. All valves of significance to the integrity of the metering station shall be accessible for inspection to secure against leakage.

All parts of the metering system shall be easily accessible for maintenance, inspection and calibration.

*Multiphase measurement*

Multiphase measurement may be used if traditional single phase measurement of hydrocarbons is not possible for financial reasons. The multiphase meter can then be used as a fiscal meter.

The following elements shall be satisfactorily documented to allow use of a concept based on multiphase measurement, cf. Chapter VII and Section 18:

- The operator shall present a concept to the Norwegian Petroleum Directorate for comments and formal processing well before submitting the Plan for Development and Operation (PDO). An estimate of the expected measurement uncertainty shall be presented, combined with financial figures for the risk of loss between production licenses (cf. NORSOK I-105), Annex C).
- The main principles of the operations and maintenance philosophy shall be described.
- Possibility to calibrate meters against test separator or other reference.
- Redundancy in sensors and robustness in the design of the measurement concept.
- Relevant PVT (equation of state) model and representative sampling opportunity to be able to perform a sound PVT calculation.
- Design of inlet pipes to ensure similar conditions if multiple meters are used in parallel.
- Flexibility in the system for handling varying GVF (gas volume fraction).
- The planned method for condition monitoring and/or planned calibration interval shall be described.
- The planned method and interval for sampling and updating PVT data shall be described.

When the multiphase meters are part of the fiscal measurement system, they shall be treated as other fiscal measurement equipment and the administrative requirements which apply pursuant to these Regulations shall therefore be fulfilled.

### Section 13a
### Measurement systems for liquids other than water

Measurement systems for liquids other than water which are purchased for use in the petroleum industry, or which are put into use after 30 October 2006 within the scope of this regulation, shall be approved by a notified body according to the procedures for conformity declaration, cf. the Regulation for measuring systems for liquids other than water, section 4 and regulation 20 December 2007 no. 1723 “Regulation for measurement units and measurement, chapter 4. Moreover, the same regulation section 8-1 applies. The transitional provisions for measurement equipment covered by the directive 2004/22/EF, apply.

The measuring systems for liquids other than water shall have conformity declaration and conformity marking, which include supplementary metrology marking. This also applies if the measuring system is designed and produced solely for own purposes. The equivalent requirements apply to modules of a measuring system if pursuant to requirements stated in the Regulation for measuring systems for liquids other than water.

When in use the measuring systems for liquids other than water shall as a minimum fulfil the requirements of this regulation section 8 a.

### Section 14
### The mechanical part of the metering system

The mechanical part of the metering system shall be designed so that representative measurements are achieved as input signals for the fiscal calculations (cf. Section 8).

Provision shall be made for necessary redundancy and the possibility of verification of the gas and liquid metering devices.

When turbine meters are used for liquid metering, a permanent prover shall be available for calibration of the metering devices.

It shall be possible to calibrate the prover at the place of operation.

If other types of flow meters are used for liquid metering, permanent equipment for calibration of the metering device shall be available.
It shall be documented that surrounding equipment will not affect the measured signals.

**Section 15**
**The instrument part of the metering system**

Pressure, temperature density and composition analysis shall be measured in such way that representative measurements are achieved as input signals for the fiscal calculations (cf. Section 8).

**Section 16**
**The computer part of the metering system**

The computer part of the metering system shall be designed in such way that the fiscal calculations may be carried out within the stipulated uncertainty range (cf. Section 8).

The computer part of the metering system shall be equipped with various security functions to ensure that the fiscal values cannot be changed as a result of incidents of a technical nature or as a result of a manual fault.

With regard to reports the computer part shall be capable of documenting the various fiscal parameters and the fiscal volumes calculated.

The computer part shall have uninterruptible power supply. It shall be ensured that faults are detected as an alarm and that a back-up system is activated. A power failure shall not be able to cause measured fiscal data to be deleted from the storing unit of the computer.

**Section 17**
**Requirements relating to sampling**

Sampling shall be carried out in a manner which ensures that representative amounts are sampled.

Sampling shall be automatic and flow proportional. In addition it shall be possible to carry out manual sampling.

With regard to oil and condensate the necessary mixing equipment shall be installed upstream of the sampling probe.

# CHAPTER V
# REQUIREMENTS RELATING TO CALIBRATION AND VERIFICATION ETC. PRIOR TO STARTUP OF THE METERING SYSTEM

## Section 18
## Application for consent

The licensee shall obtain consent from the Norwegian Petroleum Directorate prior to startup of the metering system.

Consent for carrying out major rebuilding or change in the purpose for use for the metering system shall also be obtained.

If the basis for consents granted in accordance with the first paragraph of this section is significantly changed, the Norwegian Petroleum Directorate may require the licensee to obtain a new consent before the activities are continued.

Prior to startup of the metering system, procedures shall be prepared for operation, maintenance, calibration and verification. The procedures shall ensure that the metering system is maintained to the standard to which it is designed.

Procedures for calibrations and verifications to be carried out in order to prepare the metering station for startup, shall be forwarded to the Norwegian Petroleum Directorate enclosed with the application.

## Section 19
## General

Calibrations and verifications as described in this Chapter shall be carried out prior to startup of the metering system at the place of operation.

The Norwegian Petroleum Directorate shall have the opportunity of being present when the activities are carried out.

## Section 20
## Calibration of mechanical part

The prover volume shall be calibrated:
a) before the metering system is delivered from the place of manufacture
b) prior to startup at the place of operation.

The mechanical parts critical to measurement uncertainty shall be measured or subjected to flow calibration in order to document calibration curve.

The fully assembled fluid metering system shall be flow tested at the place of manufacture and a functional test shall be performed on flowmeters.

Statistical methods to provide documentation for repeatability requirements may be used.

## Section 21
## Calibration of instrument part

The instrument loops shall be calibrated and the calibration results shall be accessible.

The instrument loops shall be calibrated at a number of values necessary to detect any non linearity errors within its working range. Calibration of the instrument loops shall be carried out using the display reading of the visual signal from the computer part.

**Section 22**
**Verification of computer part**

Verification of the computer part shall be carried out for each metering tube to confirm that all functions are operational.

Each independent program routine shall be verified to show that calculations are carried out with requirements equal to or better than those mentioned in Section 8 of the present regulations. Integration shall be verified with at least three values in the flow range.

The calculations for calibrations as mentioned in Section 20 of these regulations shall be verified. This includes K-factor in respect of the individual calibration and the average value within the predetermined range of variation.

## CHAPTER VI
## REQUIREMENTS RELATING TO OPERATION OF THE METERING SYSTEM

**Section 23**
**Maintenance**

**T**he metering system shall be maintained to the standard according to which it is designed.

The equipment which is an integral part of the metering system, and which is of significant importance to the measuring uncertainty, shall be calibrated using traceable equipment before start of operation, and subsequently be maintained to that standard.

Control to ensure that equipment mentioned in the first paragraph of this section is within given limit values shall be carried out regularly by qualified personnel. If during calibration equipment is shown to be outside the given limit values, correction shall be carried out by qualified personnel or by calibration and associated correction in a competent laboratory. Traceable calibration of test instruments shall be carried out regularly by competent laboratories.

**Section 24**
**Operating requirements for the prover**

The meter prover volume shall be calibrated annually
Calibration shall also be carried out if the volume may have changed as a result of equipment failure.

**Section 25**
**Operating requirements for flow meters**

Turbine meters for oil shall be calibrated against the permanent meter prover with a repeatability such that 5 consecutive single calibrations in sequence fall within a range of 0,05 % of the average calibration factor.

The calibration factor for the flow meters shall be within the control limits according to recognised standard. Flow meters installed after workover, modification or replacement shall immediately be calibrated to verify that they meet the requirements to linearity and repeatability.

After startup of the metering system, calibration of flow meters shall be carried out in order to verify requirements to repeatability and linearity. It shall furthermore be verified to what extent the calibration factor is affected by flow volume, temperature, pressure and crude composition when these vary within their normal operating range.

The calibration of flow meters shall satisfy the following requirements:

a) If there is a correlation between calibration factor and flow rate, temperature, pressure, density, viscosity or composition, calibration factor limits shall be established.
   A new calibration shall be carried out if the limits are exceeded.
b) The time interval between calibration of the flow meters shall not exceed four days. Calibration factor for flow meters in use shall be established for each tanker loading.

Statistical methods may be used to document requirements to repeatability.

The orifice plates shall be inspected with regard to edge sharpness, surface roughness and flatness. An inspection shall be carried out at startup and then once a month during the first six months. Subsequently the intervals may be extended, however if at a later time damage or wear-and-tear is detected, the interval between inspections of the orifice plates shall be reduced. The orifice plate shall also be inspected after incidents which may have affected the fiscal measuring quality. The orifice plates shall be certified prior to installation in meter tubes and subsequently if visible damage is detected.

In the case of ultrasonic flow measurement of gas the condition parameters shall be verified.

During orifice plate gas measuring or ultrasonic gas measuring the meter tubes shall be checked if there is indication of change in internal surface.

## Section 26
## Operating requirements for instrument part

All sensors shall be monitored continually and/or shall be regularly calibrated in accordance with the requirements of Section 8. Calibration shall comprise several values in the sensor's operating range. If the outlet signals from the sensors deviate from the preset limits, necessary maintenance and subsequent new calibration shall be undertaken.

The calibration methods shall be such that systematic measurement errors are avoided or compensated for.

Gas densitometers shall be verified against calculated density or other relevant method.

Online gas chromatographs shall be validated against a traceable reference gas with a stipulated frequency. Pursuant to the uncertainty statement in Section 8, validation criteria shall be stipulated. If a gas chromatograph is outside the stated criteria during validation, calibration shall be performed and new factors established. A new validation shall be performed following such a correction to confirm that the gas chromatograph is now within the given test criteria.

Variations in gas composition shall be monitored and, in the event of variation exceeding ± 5 %, a reference gas with a different calorific value and a new linearity test should be considered.

### Section 27
### Operating requirements for computer part

Critical data shall be filed regularly. Procedures shall be established for handling of fault messages from the computer part or faults otherwise discovered.

In the case of software changes and replacement of computer parts an independent verification shall be carried out of the calculation requirements of the computer part, cf. Section 22 of the present regulations.

## CHAPTER VII
## REQUIREMENTS RELATING TO DOCUMENTATION

### Section 28
### Documentation prior to start-up of the metering system

After the Plan for development and operation of petroleum deposits (PDO) and Plan for installation and operation of facilities for transport and utilisation of petroleum (PIO) have been approved and prior to start-up of the metering system, the operator shall have the following documents available,

a) technical description of the metering system;
b) an overview showing the location of the metering system in the process and transportation system;
c) drawings and description of equipment included in the metering system;
d) list of documentation for the metering system;
e) progress plan for the project up to the time of application for consent to use;
f) description of the operator‘s and the supplier’s management control system for follow-up of the metering system;
g) uncertainty analysis.

The Norwegian Petroleum Directorate shall on request receive documentation as mentioned in the first paragraph of this Section.

### Section 29
### Documentation relating to the metering system in operation

An archive shall be established and maintained which shall contain documentation in respect of the metering system. It shall be possible to document that the quality of measurements are as described in the present regulations and that there is accordance between reported and measured quantities.

Fixed parameters shall be easy to verify.

Correction shall be made for documented measurement errors. Correction shall be carried out if the deviation is larger than 0,02 % of the total volume. If measurement errors have a lower percentage value, correction shall nevertheless be carried out when the total value of the error is considered to be significant.

If there is doubt as to the time at which a measurement error arose, correction shall apply for half of the maximum possible time span since it could have occurred.

Reporting of $CO_2$ tax metering for payment of the $CO_2$ tax shall take place every six months as stated in Section 4 of the $CO_2$ Tax Act and in accordance with the form issued by the Norwegian Petroleum Directorate.

In the event that measured figures are not available for technical reasons, it shall be possible to document the reported figures in a manner which is acceptable from a calculation point of view.

Quantities of diesel delivered to the facility during the tax period in question shall be reported as taxable basis for calculation of $CO_2$ tax. Deduction in respect of diesel which has not been used as fuel shall be documented and reported to the Norwegian Petroleum Directorate as mentioned in the fourth paragraph of this Section.

All measured data comprised by these regulations shall be reported in the PetroBank system.

**Section 30**
**Information**

When the PDO has been approved, the licensee shall inform the Norwegian Petroleum Directorate about all significant changes that affect the quality of fiscal measurements or figures reported from them

The Norwegian Petroleum Directorate shall be informed about

a) annual plan for activities within the technical field in question;
b) procedure for ownership allocation of petroleum between licensees in production licenses.
c) measurement errors;
d) when fiscal measurement data have been corrected based upon calculations;
e) change in calibration interval;
f) change in calculation software;
g) changes affecting the basis of the consent;
h) cargo claims procedures applicable for sale of hydrocarbons in liquid phase.

**Section 31**
**Calibration documents**

Description of procedure during calibration and inspection, as well as an overview of results where measurement deviation before and after calibration is shown, shall be documented. The documentation shall be available for verification at the place of operation.

## CHAPTER VIII
## GENERAL PROVISIONS

**Section 32**
**Supervisory authorities - authority to make individual administrative decisions etc**

The Norwegian Petroleum Directorate shall supervise compliance with provisions laid down in or decisions made pursuant to the present regulations. The Norwegian Petroleum Directorate may make such individual administrative decisions as are necessary to implement provisions contained in the present regulations.

**Section 33**
**Exemption**

The Norwegian Petroleum Directorate may in particular cases grant exemption from provisions contained in the present regulations.

**Section 34**
**Penal provision**

Violation of these regulations or of decisions made pursuant to these regulations shall be punishable as stated in the Petroleum Act Section 10-17 and the $CO_2$ Tax Act Section 7, cf. the Criminal Code Chapter 3a.

**Section 35**
**Entry into force and transitional provisions.**

1. These regulations enter into force 1 January 2002.

2 As from the same date, the following amendments shall be made:

   a) Regulation for fiscal measurement of oil and gas etc. issued by the Norwegian Petroleum Directorate 3 July 1991, No. 532, shall be repealed.
   b) Regulations relating to measurement of fuel and flare gas for calculation of $CO_2$ tax in the petroleum activities, issued by the Norwegian Petroleum Directorate 12 August 1993, No. 806, shall be repealed.

3 Decisions made pursuant to the regulations mentioned in this section item 2 shall remain in force until such time as they may be repealed or altered by the Norwegian Petroleum Directorate.

4 a) The general requirements of these regulations and requirements relating to testing and operation of measuring equipment (Chapters I, II, III, V, VI, VII and VIII) are applicable to all metering systems.
   b) Requirements to design (Chapter IV) apply only to metering systems where the design was commenced after 1 January 2002. The Norwegian Petroleum Directorate may by individual administrative decisions directed at the individual operator make requirements to design fully or partly applicable to measuring equipment or metering systems designed prior to the time mentioned in the preceding sentence, cf. Section 32 of the present regulations.

**LIST OF REFERENCES**


- AGA, American Gas Association
  - AGA Report No 8, Natural Gas density and compressibility factor executable program and Fortran Code
  - AGA Report No 9, Measurement of gas by multipath ultrasonic meters
- ASTM 1945, Standard test method for analysis of natural gas by gas chromatography
- API, MPMS, American Petroleum Institute, Manual of Petroleum Measurement Standards
  - API Recommended Practice 86. Recommended practice for multiphase flow
  - ISO Natural Gas. Upstream Area – Allocation of gas and condensate (TR ISO TC 193)
  - NFOGM Multiphase Manual
- Håndbok for usikkerhetsberegning CMR/NFOGM/OD
- ISO/OIML The guide to the expression of uncertainty in measurement
- OIML R 117 Measuring systems for liquids other than water, Annex A
- ISO 3171 Petroleum liquids - Automatic pipeline sampling
- ISO 5024 Petroleum liquids and liquefied petroleum gases. Measurement Standard reference conditions
- ISO 5167-1 Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross section conduits running full
- ISO 6551 Petroleum Liquids and Gases - Fidelity and Security of Dynamic
- ISO 6976. Natural gas – Calculations of calorific values, density, relative density and Wobbe index from composition
- ISO 7278 Liquid hydrocarbons - Dynamic measurement - Proving system for volumetric meters.
- ISO 9002 Quality systems, Model for quality assurance in production, installation and servicing
- ISO 9951 Measurement of gas flow in closed conduits - Turbine meters
- ISO 1000, SI units and recommendations for the use of their multiples and certain other units
- ISO/IEC 17025 General requirements for the competence of testing and calibration laboratories
- ISO/CD 10715 Natural Gas - Sampling Guidelines
- NORSOK I-104, Fiscal measurement systems for hydrocarbon gas (Rev 3, November 2005)
- NORSOK I-105, Fiscal measurement systems for hydrocarbon liquid (Rev 3, August 2007)
- NORSOK P-100, Prosess system
- NS 4900
- NS 1024
- LNG Custody Transfer Handbook (CTH), G.I.I.G.N.L. (2001)
- ISO 13398 Refrigerated light hydrocarbon fluids – Liquefied natural gas – Procedure for custody transfer on board ship
- Regulations of 21 December 2007 no. 1738 relating to measuring systems for liquids other than water
- Regulations of 20 December 2007 no. 1723 relating to measurement units and measurement

**APPENDIX 1: FORM 1, $CO_2$-TAX, HALF-YEARLY PAYMENT**
**APPENDIX 2: FORM 2, $CO_2$-TAX, TAX ASSESSMENT PER PRODUCT**

## FORM 1 - $CO_2$ TAX
## HALF-YEARLY PAYMENT

Half-year period:

Company:

| Field/installation | Tax amount Gas | Tax amount Oil/cond. | Tax amount Sum |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| Total this period | | | |
| Total corrections | | | |
| Total interest | | | |
| | Half-yearly payment | | |

Date/sign:

For NPD internal use

| Account | Debit | Credit |
|---|---|---|
| | | |
| | | |
| | | |
| | | |
| Total | | |

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**FORM 2 - $CO_2$ TAX**
**TAX ASSESSMENT PER PRODUCT**

Half-year period:

Field/install:

Norwegian share:

Product:

| Month | Fuel ($Sm^3/1$) | Flare ($Sm^3/1$) | Vent ($Sm^3/1$) | Total ($Sm^3/1$) | Tax rate | Tax amount (NOK) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| Sum | | | | | | |

| | |
|---|---|
| Prior payment(s) | |
| Difference | |
| Interest | |
| Total | |

Date/sign:

Revised FORM 2 to be completed when correcting prior accounts.
Specification of accrued interest to be enclosed.

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# Comments to regulations relating to measurement of petroleum for fiscal purposes and for calculation of $CO_2$ tax

## CONTENTS

## CHAPTER 1
## INTRODUCTORY PROVISIONS

### Re. Section 1
### Scope

According to Section 1-4 of the Petroleum Act the regulations apply also to onshore facilities if petroleum is transported to the facility by pipeline from the continental shelf and the metering for practical reasons is carried out onshore in Norway. The Norwegian Petroleum Directorate will in such cases coordinate the supervisory activities with the Office of Weights and Measures (Justervesenet - JV) as referred to in Agreement on co-operation between the two agencies. At terminals abroad where Norwegian petroleum is landed by pipeline the Norwegian Petroleum Directorate carries out supervision of the metering in co-operation with the relevant authorities of the state in question, cf. Section 1-4 first paragraph second sentence of the Petroleum Act.

$CO_2$ tax metering

The $CO_2$ tax is calculated per field/facility. In accordance with the Act relating to $CO_2$ Tax Section 5, decisions relating to the basis and extent of the tax are made by the Ministry of Finance.

These regulations are applicable to the measurement of natural gas used for the operation of combustion machinery and to the measurement of natural gas burned off or vented to the atmosphere. Discharge of pure $CO_2$ should be taxable according to the same tax rate as natural gas used for combustion. These regulations are not applicable to other fuel than natural gas with regard to requirements applicable to metering system.

The regulations are also applicable to diesel oil used for operation of combustion machinery. Diesel is taxed for mobile facilities which undertake service functions for facilities and are associated with facilities which produce oil or gas. The diesel quantities should be documented and reported as mentioned in Section 29 of these regulations. Diesel constitutes a relatively limited part of the fuel consumption in the petroleum activities. The Norwegian Petroleum Directorate has consequently considered it to be inappropriate to impose a detailed procedure in these regulations with regard to determination of the volume of diesel oil.

When putting new fields on stream, the $CO_2$ tax starts to run from the time when petroleum from the first producing well enters into the process system of the facility. From this point on, all burning of natural gas or diesel on the facility in question will be taxable. Wells which are classified as exploration wells will also be exempted from the $CO_2$ fee when they are drilled from facilities which pay the $CO_2$ fee.

Drilling of exploration wells from mobile facilities should not be taxable. A mobile facility with a direct connection to a production facility should be subject to $CO_2$ tax.

When petroleum production ceases in connection with shutdown of a field, i.e. when the recovery of petroleum from the deposit ceases and the installation is without hydrocarbons, no further $CO_2$ tax should be payable. In the case of facilities without own production of petroleum no $CO_2$ tax should be payable after the principal function of the facility has ceased. By facilities without own production is meant for example pumping/compressor platforms.

Deduction may on application be made for water vapour or nitrogen accompanying volumes of gas for flaring for process related reasons.

NO$_x$ tax measurement

The Norwegian Petroleum Directorate is the competent authority for permanent facilities on the continental shelf and can, among other things, approve a source-specific emission factor following an application from the party liable for tax, including the measurement or calculation method used to determine the size of NO$_x$ emissions, cf. Section 3-19-7 of the Regulations dated 11 December 2001 no. 1451 relating to Excise duties.

The Directorate of Customs and Excise (TAD), represented by the Customs Regions, manages the collection and legal aspects of the tax. The Norwegian Petroleum Directorate's (NPD) responsibility covers the technical responsibility for fixed facilities on the continental shelf.

The technical follow-up of NO$_x$ emissions from mobile drilling rigs and other maritime activities is the responsibility of the Norwegian Maritime Directorate.

The tax will be calculated pursuant to requirements stipulated in Section 3-19-6 of the Regulations relating to excise duties.

If the tax is calculated according to a source-specific emission factor, documentation should be available from the operator which states the factors and method for such stipulation. This documentation should be presented to the Norwegian Petroleum Directorate. If no objections have been received from the NPD within four weeks after the documentation has been received, the new factors can be utilised.

TAD should be informed in writing when the new factors are utilised. Copies of this correspondence should be submitted to the NPD and Customs Region.

The same principle applies for introduction of Predictive Emission Monitoring Systems (PEMS). The operator should inform the NPD that PEMS has been introduced and that it is desirable to use the system for NO$_x$ tax reporting starting on a specified date. Technical explanations of PEMS should be enclosed. If no objections have been received within four weeks, this will have been accepted as a basis for NO$_x$ tax reporting. TAD, NPD and the Customs Region should be informed correspondingly as for the source-specific emission factor that a new calculation method is in effect.

With regard to flare gas, a factor of 1,4 g/Sm$^3$ of gas combusted is currently used as the emission factor.
Consideration to establish a better background experience to stipulate this factor is in progress.

The standard values listed in Section 3-19-9 of the Regulations relating to excise duties may be used for the different gas turbines and diesel motors in use.

The operator should, at all times and for each individual facility, have an updated list of equipment subject to NO$_x$ tax, as well as the factors or measurement methods in use to determine the emissions.

**Re. Section 2**
**Definitions**

Definitions according to superior legislation are not repeated in these regulations.

**Re. Section 3**
**Responsibility according to these regulations**

It is emphasised that the first paragraph of this section entails a material duty to comply with the provisions of these regulations and with individual decisions issued pursuant to the regulations. The duty to do this through implementation of necessary systematic measures follows from Section 5 of these regulations.

The operator of the individual facility will be directly responsible in relation to the duties placed with the licensees jointly pursuant to the Petroleum Act and the Act relating to $CO_2$ Tax, such as the design, purchase and operation of metering systems with associated reporting and payment of tax. The provisions of these regulations are consequently addressed to the operator on behalf of the licensees.

**Re. Section 4**

**Requirements to the petroleum activities in general**

In comments to the individual sections the use of a number of industry standards or other normative documents is recommended, in some cases with additional reference as stated in the comments, as a way to comply with the requirements of the regulations. Through this reference the recommended solution becomes a recognised standard. In areas where no industry standards are available, these regulations in some cases contain, in the comments to the provision in question, a description of solutions that represent ways in which to comply with the requirements of the regulations. Such recommendations will have the same status as reference to industry standards as mentioned. According to Section 4 the licensee may as a rule assume that the recommended solution will satisfy the regulation requirement in question.

The regulations and the comments are meant to be seen as a whole in order to achieve the best possible understanding of the level aspired for through these regulations. Standards recommended in the comments will be central in the interpretation of the individual regulation requirements.

Total measuring uncertainty as mentioned in Section 8 of these regulations will be decisive in selecting the measuring methods to be used.

The use of recognised standards as mentioned in the first paragraph is optional inasmuch as other technical solutions, methods or procedures may be selected.

The basis for using alternative methods may be:

a) documentation demonstrating that measuring uncertainty and operational reliability is equal to or better than conventional equipment,

b) in metering for allocation purposes, when there is a cost disproportion between a conventional system compared to a simplified system (cf. NORSOK I-105, Annex C).

Clarification with regard to the measurement concept should emerge from the process in connection with approval of Plan for development and operation of a petroleum deposit (PDO) or Plan for installation and operation of facilities for transport and utilisation of petroleum (PIO) or an application for exemption from such plan.

Approval of PDO or PIO entails authorisation of the measurement concept with associated uncertainty level. A possible exemption, cf. Section 33, should only be applicable to deviations from regulation requirements which are not identified in the PDO or PIO.

## CHAPTER II
## REQUIREMENTS RELATING TO MANAGEMENT CONTROL SYSTEM ETC.

This chapter contains requirements to management control systems within the scope of application of both the Petroleum Act and the Act relating to $CO_2$ Tax. It has been deemed appropriate that common provisions are applicable to both these areas.

Reference is further made to Section 10-6 of the Petroleum Act and Sections 56, 57 and 58 of the Petroleum Regulations.

### Re. Section 5
### Management control system

A management control system for measuring should contain:
a) uncertainty limits accumulated and by component;
b) the chain of responsibility for the follow-up of measuring equipment quality;
c) apportionment of responsibility between different sections of the organisation and interfaces between them.

For verification of documentation:
a) persons who receive the documentation and in what order;
b) what is done with the documentation;
c) how information from the documentation is handled;
d) after processing, how and where the documentation is filed;
e) what action is taken if the evaluation of data requires follow-up.

For verification of equipment:
a) a description of purpose, guidelines for implementation and definition of the section responsible;
b) a description of equipment verified and specification of equipment to be used in the process;
c) a description of the necessary preparations;
d) a systematic description of how the verifications are carried out;
e) a description of how the derived results are handled to ensure quality;
f) a reference to the log book for the metering systems;
g) an example showing how results, remarks and deviation limits should be registered.

For use of equipment:
a) a description of the equipment in service during normal operation;
b) a procedure on how to handle situations where any of the in-service equipment fails during normal operation;
c) a summary of important information and how relevant experience and information is conveyed from one shift of personnel to the next;
d) a list of alarms and a procedure on how they are handled.

The management control system may comprise other elements than those mentioned in this list.

### Re. Section 6
### Organisation and competence

The licensee should see to it that the person responsible as mentioned in this section second paragraph exercises a particular professional responsibility to see that the metering system at all times complies with the provisions in force. Furthermore the licensee should see to it that the person responsible for the metering system is kept informed about metering systems under planning, manufacture and completion.

The licensee should ensure that:

a) a job description exists for each position, which includes qualifications requirements;
b) procedures are established and maintained to identify training needs;
c) all personnel are properly trained to perform their dedicated tasks;
d) a summary of qualifications, training and experience is established and maintained in respect of all personnel with tasks comprised by the present regulations.

**Re. Section 7**
**Verification**

The intention with verification is to confirm, by checking and acquiring evidence for, compliance with specified requirements. By independent verification as mentioned in the second sentence of this section is meant that the operator may be required to use a third party for the execution of this function.

## CHAPTER III
## GENERAL REQUIREMENTS RELATING TO MEASURING AND THE MEASUREMENT SYSTEM

**Re. Section 8**
**Allowable measuring uncertainty**

The basic principles for uncertainty analysis are stated in the ISO “Guide to the Expression of Uncertainty in Measurement” (the Guide).

Manual for uncertainty calculation, CMR/NFOGM/OD, comprises both oil and gas measurement.

± has been removed from the tables, as it is sufficient to state a numerical value when a 95 % confidence level is used.

When reference (master) meters are used to calibrate operational meters, the meters should have a significantly better (30 %) linearity and repeatability than what are specified as maximum limits in Table 2.

A total uncertainty better than the stipulated measurement uncertainty for fuel gas blend measurement stations (1,5 %) requires that the density is determined, so that the total uncertainty is within the stipulated limit.

In relation to a number of parameters, measuring uncertainty is defined in relation to measured value. The operating range for sensing elements should be adapted to the normal range of measurement. When a metering tube is started up or shut down, there will be short periods where one is outside the operating range and uncertainty limits.

In some special cases the working range for pressure sensing elements is such that the requirements given for pressure measurement oil, gas; pressure measurement fuel, flare gas and differential pressure measurement cannot be fulfilled. After informing the Norwegian Petroleum Directorate, as given in section 30, the given equipment can be used for the purpose.

When prover calibration is carried out with low-density fluids, as condensate and LPG, the repeatability will be slightly higher because of CTL temperature sensitivity.

Requirements for ultrasonic fuel gas meter should be as given in NORSOK I-104, article 6.2.2.4.

With regard to sampling and analysis of LNG reference is made to LNG Custody Transfer Handbook (CTH), NORSOK I-104 and ISO 13398 Refrigerated light hydrocarbon fluids – Liquefied natural gas – Procedure for custody transfer on board ship.

**Re. Section 8 a**

**Allowable measurement uncertainty for measuring systems for liquids other than water**

No comments

**Re. Section 9**

**Units of measurement**

Recognised standard is ISO 1000 or NS 1024. With regard to pressure, the unit ‘bar’ may be used.

**Re. Section 10**

**Reference conditions**

The reference conditions mentioned in this section are from NS 4900, ISO 5024 or NORSOK I-104 and I-105. When petroleum products are sold, the mass (vacuum weight) should in accordance with SI units be used as fiscal quantity.

**Re. Section 11**

**Determination of energy content etc.**

Recognised standard for determination of energy content will be ISO 6976 or equivalent. Reference temperature for energy calculation should be 25 o C/ 15 o C (o C reference temperature of combustion/ o C volume). When continuous gas chromatography is used, recognised standard will be NORSOK I-104.

**Re. Section 12**

**Bypassing the metering system**

When oil is loaded into tankers a recirculation line for the oil metering station may be allowed.

When loading petroleum products in small batches, there will be a need to install a by-pass loop for recirculation at the metering station. A prerequisite is that a system for valve integrity is used.

Any bypass tube should be closed using blind flense or shutoff valve with double block and bleed system, so that oil can not pass without being measured.

## CHAPTER IV
## REQUIREMENTS TO DESIGN OF THE METERING SYSTEM

**Re. Section 13**

**Requirements to the metering system in general**

Meters without a separate calibration unit (in-line prover) should be tested with liquid or gas using test conditions that are as close to the operational conditions as possible.

When the Regulations mention duplicated instrument functions, this does not mean that the primary meter should be duplicated. The duplication/monitoring can i.e. for Coriolis and ultrasonic meters be achieved using different signal types.

In gas metering the maximum flow velocity during ultrasonic metering should not exceed 80 percent of the maximum flow rate specified by the supplier.

One metering tube where maintenance is provided for will fulfil the regulation requirement to a fuel gas metering station.

With regard to maintenance of a fuel gas metering station with only one metering tube, there should be a bypass.

If flow straighteners are used, they should be of a recognised make.

Recognised standards for shut-off valves are NORSOK I-104, I-105 and NORSOK P-001.

Vents with double tightening and intermediate expanding chamber can be used.

The block-and-bleed valves should have an equalising line to allow pressure to be equalised before they are opened.

The need for electronic equipment being approved as given in OIML R 117 Measuring systems for liquids other than water, Annex A should be considered.

**Re. Section 13a**
**Flowmeters (for liquids other than water)**

The NPD metering regulation is the amendment of 22 August 2006 no. 1014, changed as a consequence of Norway's implementation of the Directive 2004/22/EU, Measuring Instrument Directive (MID), cf. the EEA treaty, annex II chap. IX, concerning measuring instruments no. 27. For measurement in the petroleum sector, included onshore terminals, this requirement only comprises measuring systems for liquids other than water. The requirements for these measuring systems are changed according to the MID and are harmonized with the Regulation of 21 December 2007 no. 1738, "Requirements for measuring systems for liquids other than water" adopted by Department for Industry and Trade (NHD) and Norwegian Metrology Service. The regulation mentioned above section 4, determines which requirements measuring systems should fulfil to be made available on the market and to be used in connection with economical transactions. The procedure for conformity evaluation is in section 4-11 of this regulation. The modules to which the procedures refer to is described in attachment 1 to the above mentioned regulation. The requirements in the annex are regarded as minimum requirements, such that the measuring equipment should at least fulfil these minimum requirements. The Licensee, as user, and the manufacturers are thereby free to introduce more stringent requirements.

The changes are not valid for existing flow meters used in the petroleum industry. This exemption applies to both technical requirements and requirements for use.

The Directive is primarily directed to the manufacturer of measuring instruments, but is also applicable for others selling measuring instruments. Measuring instruments covered by MID should fulfil technical requirements stated the directive before they are made available on the market. The pre market survey includes conformity assessment done by a notified body and a conformity marking to prove that the requirements of the Directive are fulfilled. It follows of the instrument specific annexes to MID which modules a specific measuring instrument (system) should be approved in accordance to, cf. MI-005 and section 4 in Regulation for measuring systems for liquids other than water. According to the directive a manufacturer which produce an instrument for own use, is considered a manufacturer of a measuring instrument regulated by MID.

For existing measuring systems which have been in use or made available on the market before the entry into force date (30 October 2006), the requirements of the NPD metering regulation apply as in the past (MID does not apply). Same apply to measuring equipment sold in the EEA before the time of implementation, and thereafter resold for use. Transitional provisions are prevailing for measuring systems which are type approved before the time of implementation, cf. section 8-1 in the regulation for measurement units and measurement.

The changes will not apply where the Regulations relating to measurement of petroleum for fiscal purposes come into force as a consequence of a treaty with a foreign state, cf. the Petroleum Act section 1-4 first paragraph.

Implementation of the MID Directive for liquid measurement stations will, in practice, entail that the operator orders a liquid measurement system from a supplier/manufacturer. Before ordering, and following a dialogue with the Norwegian Petroleum Directorate, the operator should clarify whether issuance of an MID certificate will be relevant for the liquid measurement station in question. If a MID certificate is to be issued, it will be the supplier's responsibility to use an approved notified body (TKO) in Norway or abroad to issue a MID certificate.

Liquid measurement stations for crude oil/product ships or pipeline systems are covered by MID.

**Re. Section 14**
**The mechanical part of the metering system**

Design of the metering system for hydrocarbons in liquid phase
Recognised standard is NORSOK I-105 and American Petroleum Institute (API), Manual of Petroleum Measurement (MPMS) ch.4 and ch.5.

When an ultrasonic meter is used in allocation metering for liquid, a concept with reference meter and portable prover should be used.

Prover oil
Recognised standards for prover design are NORSOK I-105 and API, MPMS ch.4.

Determination of prover volume based on pulse interpolation may be according to ISO7278.

It is not recommended to reduce the prover volume down towards the design criterion, as this may lead to repeatability problems.

Compact prover may be used.

Compact prover
Equipment and manning should be available so that it is possible if required to establish a new volume within four days.

With regard to design and calibration the following should be complied with:
a) water calibration;
b) list of critical parts, which should be available for necessary maintenance;
c) compact provers should be equipped with leak detection facilities in the total calibrated area;
d) filters should be installed upstream;
e) compact provers should be installed vertically;
f) compact provers should be installed upstream of the flow meter so that the downstream volume is used.

Flow meters liquid
At the ultrasonic liquid gauge the upstream length should be 10D including the flow straightener.

Design of the metering system for hydrocarbons in gas phase
Recognised standards are NORSOK I-104, ISO 5167-1, AGA Report no. 9 and ISO 9951.

Flow profile gas
When orifice plate is used, the Reynolds number should not exceed the highest number for which there exists basic calibration data ($3,310^7$).

Differential pressure should not exceed 500 mBar.

Design of the metering system for fuel gas

Recognised standards are NORSOK I-104, ISO 5167-1, AGA Report no. 9 and ISO 9951.

Measurement methods for fuel gas may be:

a) orifice plate with pressure and temperature compensation;
b) turbine meter with associated pressure and temperature compensation; (not insertion turbine)
c) ultrasonic meter with minimum two output beams and associated pressure and temperature compensation.

The diameter ratio β may vary between the outer limits referred to by ISO 5167. The differential pressure should not exceed 1 Bar.

Density measurement may be omitted and be calculated according to AGA report no.8.

Design of the metering system for flare gas

Recognised standard is NORSOK I-104.

Alternative methods
When metering oil and gas for allocation purposes test separator measurement in combination with multiphase meters, which are calibrated against the test separator, may be used. Test separator measurement should in such cases be improved in relation to conventional systems.

**Re. Section 15**
**The instrument part of the metering system**

Recognised standards are NORSOK I-104 and I-105.

The signals from the sensors and transducers should be transmitted so that measurement uncertainty is minimised. Transmission should pass through as few signal converters as possible. Signal cables and other parts of the instrument loops should be designed and installed so that they will not be affected by electromagnetic interference.

When density meters are used at the outlet of the metering station, they should be installed at least 8 D after upstream disturbance.

When oil is loaded into tankers, the density may be determined by analysing the contents of a sample container.

When petroleum products are measured, density may be calculated by using a recognised standard.

In measuring petroleum products, there may be a need to consider simplifications in the instrumentation.

When gas metering takes place, density may be determined by continuous gas chromatography, if such determination can be done within the uncertainty requirements applicable to density measurement. If only one gas chromatograph is used, a comparison function against for example one densitometer should be carried out. This will provide independent control of the density value and that density is still measured when GC is out of operation.

Measured density should be monitored.

**Re. Section 16**
**The computer part of the metering system**

Recognised standards are NORSOK I-104 and I-105.

The computer part of the metering system should not have any functions other than those associated with the metering system. Where a number of digital computers are used, the locations where the different calculations are performed should be defined. To avoid sources of error, the part of the computer performing the fiscal calculations should be connected to the other computer equipment in such a way that errors are avoided.

With regard to pulse transmission from flow meters it should be possible to read the signal as a number of pulses.

Quantities registered during calibration should be registered separately, irrespective of measured quantities.

Figures for accumulated fiscal quantities, which are comprised by the present regulations, should for each meter run and the total metering system be stored in electronic storage units. The storage units should be secured in such a way that they cannot be zeroed or altered unless a security system is followed.

In ultrasonic measuring the computer part should contain control functions for continuous monitoring of the quality of the measurements. It should be possible to verify time measurement.

With regard to $CO_2$ tax measurements the alarm function may be carried out by transferring a general alarm to a manned control room.

With regard to fuel gas metering using flow meter, a simpler signal transmission than ISO 6551 Class A may be considered.

**Re. Section 17**
**Requirements relating to sampling**

Recognised standards are NORSOK I-104 and I-105, ISO 3171 (oil) and ISO 10715 (gas), NFOGM-manual for water in oil measurements (2001).

In respect of oil and gas sampling it should be ensured that equipment in direct contact with hydrocarbons is not corroded by the substance from which it is sampling. Operating instructions should be mounted in the sampling cabinets.

The liquid samples from the sampling system should be analysed at a laboratory according to ISO 103337, Crude petroleum - Determination of water - Coulometric Karl Fischer titration method. Certified syringes of digital model should be used.

Homogenisation of samples to be analysed should if necessary be documented.

The sampling cabinet for oil and condensate should in the case of pipeline transportation have a daily and a monthly sample container. When loading into a tanker one sample container will be sufficient. The equipment should be designed so that the samples can be transported to a laboratory for analysis. The filling of sample containers should be monitored and the number of samples should be not less than 10.000 during the sampling period.

Water in oil may be determined fiscally at allocation metering stations by using continuous metering.

When the water content is in excess of 5 volume percent, water in oil should be determined by direct measuring using a water-in-oil meter.

The sampling cabinet for gas should have instrument pipes and hoses of such a material that gas molecule diffusion cannot take place.

It should be possible to evacuate air out of the system before placing new sampling cylinders in service.

Installation of automatic sampling equipment will not be required in respect of $CO_2$ tax metering.

## CHAPTER V
## REQUIREMENTS RELATING TO CALIBRATION AND VERIFICATION ETC. PRIOR TO START-UP OF THE METERING SYSTEM

### Re. Section 18
### Application for consent

Application for consent should be submitted no later than 20 working days prior to planned start-up of the activity that the application for consent refers to.

It is important that it during the project phase is established a good communication between the operator and the NPD. This is to ensure a common understanding of the requirements between the authority and the licensee.

How incidents connected with the fiscal measurement system are to be registered, and how follow-up is to be carried out, should be described.

The application for consent should furthermore contain allocation procedures and cargo claims procedures, if any.

The application for consent should also contain a system for calculation of the mass balance for the flow of hydrocarbons through the processing plant, so that flare gas quantities can be calculated when necessary.

**Re. Section 19**
**General**

When equipment is taken into use, the calibration data furnished by the supplier may be used, if they are having adequate traceability and quality. If such is not the case, the equipment should be recalibrated by a competent laboratory. By competent laboratory is meant a laboratory which has been accredited as mentioned in recognised standard EN 45000/ISO 17025, or in some other way has documented competence and ensures traceability to international or national standards.

Based on the work progress plan of the operator, the Norwegian Petroleum Directorate will decide which activities it will want to be witnessed.

A test procedure which clearly states the requirements should be prepared in advance for all tests of critical equipment components. The test procedure should contain references to relevant regulations and standards.

**Re. Section 20**
**Calibration of mechanical part**

The checks referred to will for example be measuring of critical mechanical parameters by means of traceable equipment.

With regard to requirements to calibration of flow meters and provers, reference is made to Section 8 of these regulations.

Volumetric measure used for calibration of prover should be certified annually. The volumetric measure volume should be certified by gravimetric method with reference to national standard with uncertainty better than ± 0,01 %.

With regard to small one-way provers it should be verified that the 4 volumes are mutually consistent. The spread should not exceed 0,02 % for K-factors or flow rates.

There should be a clear distinction between the four volumes.

Following volume calibration or rebuilding activities it should be verified for all in-line provers that the four volumes are consistent. This is done by establishing a K factor for a meter, then changing the volume and then repeating the calibration sequence.

Recommended calibration methods for provers:

a) “Master prover/master meter” method.
Before and after or simultaneously with this calibration the “master meter” should be checked against the “master prover”, with the same requirements to repeatability as mentioned in Section 8. The calibration requirement is met if the “master meter” calibration factors before and after the calibration of the prover deviate from each other by less than 0,02 %.

b) “Master tank/master meter” method.
The same calibration requirements as in item a) are applicable.

c) “Water draw” method.

Three consecutive individual calibrations should be carried out, and one of these should have a flow rate which is different from the two others. The repeatability requirements are the same as for the methods mentioned in items a) and b). Determination with volumetric reference will be acceptable in the case of factory testing (FAT) if determination with gravimetric reference is carried out before start-up at the place of operation.

During calibration as per item a) and b) five consecutive individual calibrations should be carried out at each measurement location.

The linearity and repeatability of the flow meter should be tested in the highest and lowest part of the operating range, and at three points naturally distributed between the minimum and the maximum values.

**Re. Section 21**
**Calibration of instrument part**

Measurement results should be from calibration equipment equivalent to that which will be used for calibration of the transmitters at the place of operation. Transmitter may be omitted and replaced by a signal generator. The effect of the barriers on measurement signals should be determined.

Verification of the system for pulse transmission from the turbine meters should be carried out. Recognised standard is ISO 6551. The reading of the pulses should be undertaken on the computer part and also on external counters. 100 000 pulses should be simulated and in the event of deviation of two pulses the simulated pulse number should be doubled.

When new metering systems are started up, instruments may be kept in storage for a period of time exceeding the recommended time for calibration. In such cases calibration should be carried out by a competent laboratory before the instruments are taken into use.

During calibration of turbine meters with a low K factor and/or during use of a compact in-line prover, it may be appropriate for each calibration to consist of multiple repetitions, so as to increase the calibration volume and the number of pulses from the turbine meter.

**Re. Section 22**
**Verification of computer part**

Alarm handling and reporting should be verified with manually entered measurements for each metering tube and for the entire metering system. The system should be verified for voltage failure and data link transmission failure.

Verification of pulse alarm for the turbine meters should be carried out and alarm should be activated if deviation occurs between the two pulse trains.

Verification of the performance of the electronic equipment should be carried out and should be in accordance with the climatic and mechanical environment that the equipment will be subjected to.

# CHAPTER VI
# REQUIREMENTS RELATING TO OPERATION OF THE METERING SYSTEM

## Re. Section 23
## Maintenance

When using maintenance systems based on integrated operations, then it should be ensured that the supervision of the fiscal parameters and scheduled maintenance should be performed in a systematic and controlled manner.

To ensure continuous quality in the measurements, it should at all times be relevant technical support personnel available for interpretation, analysis and eventual correction of error modes.

When two instruments do the same measurement with the same quality, then one of the instruments should be identified as in use and the other should then have a monitoring/back up function.
A change between the two instruments should just take place when the instrument in service fails.

## Re. Section 24
## Operating requirements for the prover

Calibration of provers is dealt with in the comments re. Section 20. If the meter prover volume deviates by more than ± 0,04 % compared with the volume at the last calibration, a troubleshooting procedure should be carried out in order to discover the reason for the deviation.

A lower calibration frequency can be used for in-line provers, based on a technical assessment of the stability of previous calibrations (better than ± 0,02 % of the average volume for three consecutive), considered in a cost-benefit perspective.

On the basis of the assessment in the paragraph above, the existing in-line prover calibration interval may be increased to double the existing interval. A new assessment can be made when experience has been gathered from this calibration frequency.

If an assessment of the calibration results from multiple in-line provers indicates systematic deviations, the Norwegian Petroleum Directorate should be consulted concerning the issue of whether to implement the calibration result.

For measurement systems used with low density fluids, as condensate and LPG, the limiting values given in this remark can be increased, ref. re. Section 8.

## Re. Section 25
## Operating requirements for flow meters

Recognised standard for monitoring of turbine meter K-factors is API MPMS ch.13.

With regard to flare gas meters the zero point check should be carried out regularly with an external unit. Depending on the meter manufacturer, it may be relevant to perform other checks to verify the meter's quality.

Condition Based Monitoring (CBM)" should be used for multi-beam ultrasonic meters.
Examples of parameters that may be included in a condition based monitoring system:

- First condition check (foot print), registered at the flow laboratory
- Signal-to-noise ratio (SNR)

- Signal quality (Gain and Burst)
- Flow profile monitoring (flatness, symmetry, turbulence and swirl)
- Velocity of sound (VOS)
- Various forms of density comparison
- Velocity of each individual sound path

The monitoring systems will vary somewhat between the different suppliers.

Deviation limits for the various parameters should be determined before start-up or as soon as possible thereafter.

Recalibration should be carried out if the meter has a poor maintenance history.

When petroleum products are loaded into tankers in small batches it may be expedient to utilise K-factor established during recirculation.

With regard to requirements to repeatability and linearity for calibration of flow meters, reference is made to Section 8 of these regulations.

Inspection and cleaning of the meter tube should if necessary be carried out when the meter tube sections are disassembled.

The operating requirements for the turbine meter deviate from the design criteria given in Section 8 and are specified in Section 25.

**Re. Section 26**
**Operating requirements for instrument part**

When monitoring functions are in operation, condition based maintenance may be used to extend calibration intervals.

Instruments used for calibration should be kept separated from other instruments.

The interval between calibrations may be increased if stability of the measuring equipment is documented.

In the case of condition based maintenance a number of transmitters for each metering station parameter should be calibrated at least once annually in order to ensure traceability. A comparison of these with corresponding metering station transmitters should be carried out in order to ensure traceability.

During preparation of control limits for the individual components of online gas chromatographs (benchmark tests), the start point should be the GC uncertainty requirement and divide by the square root of the number of components. Deviations for the individual component and for combined values should always be checked against normalized values to limit the effect of weather conditions on the figures. Deviations for each individual component should not entail a deviation exceeding 0,1 % of the calorific value or standard density.

With regard to facilities operated with regular calibration and correction, the transition to the benchmark principle for GC should be carried out as soon as practically feasible, for example in connection with equipment upgrades.

Recognised standard for uncertainty of traceable reference gases is given in NORSOK I-104.

**Re. Section 27**
**Operating requirements for computer part**

Alarms from the metering system should after start up be reviewed in a systematic way, to reduce numbers and establish an effective interface against other control room equipment.

Calculation requirements should be verified by using an independent system (PC).

## CHAPTER VII
## REQUIREMENTS RELATING TO DOCUMENTATION

**Re. Section 28**
**Documentation prior to start-up of the metering system**

No comments.

**Re. Section 29**
**Documentation relating to the metering system in operation**

The first and second paragraphs of this section apply to all measuring referred to in these regulations. Documentation as mentioned in the first paragraph of this section will include specifications, calculations and drawings relating to the metering system, as well as operating procedures and other relevant documentation.

The general rule referred to in the Petroleum Act Section 10-4 with regard to material and information entails that documentation relating to fiscal metering as referred to in these regulations should be available in Norway irrespective of where the operational organisation is located. This does not entail any prohibition against storing documentation abroad, as long as it can be made available to the Norwegian Petroleum Directorate within a reasonable length of time. In some cases, e.g. during supervision of metering stations located abroad, the most practical solution will be that the documentation is made available to the Norwegian Petroleum Directorate on location. Operational organisations located outside Norway should have the documentation available at the place of operation and available to the Norwegian Petroleum Directorate on request.

If any of the equipment components drift inside their variation range and this is detected by routine calibration, this will not constitute basis for correction.

A correction should, however, not be implemented if the cost of the correction work is higher than the value of the wrongly measured quantity that should be corrected for.

Standard forms for reporting of $CO_2$ tax are included as Appendix 1 and 2 to these regulations.

The operator may, if practical, report diesel consumption to the NPD according to the same principle as for reporting to Klif for the Climate Quota Regulations.

**Re. Section 30**
**Information**

The cargo claims procedures should be drawn up in such a way that when oil is sold in tanker loads from an offshore loading buoy, the correction limit should be the one which is internationally accepted for trade in oil, 0,5 %. A correction should only be implementable when both the ship's figures in port and the terminal's figures deviate from the figures of the metering station by 0,5 % or more.  Furthermore, failure in connection with the official measuring equipment should be demonstrated before corrections may be carried out. On the Norwegian part of the continental shelf, 0,3 % has often been used for crude oil cargoes from the petroleum activities.

**Re. Section 31**
**Calibration documents**

No comments.

## CHAPTER VIII
## GENERAL PROVISIONS

**Re. Section 32**
**Supervisory authorities - authority to make individual administrative decisions etc.**

The Ministry of Petroleum and Energy is the appeal body in relation to decisions made by the Norwegian Petroleum Directorate pursuant to these regulations.

With regard to the basis for and extent of the $CO_2$ tax, the Ministry of Finance is the appeal body.

Any appeal against a decision should be forwarded through the Norwegian Petroleum Directorate, cf. Chapter VI of the Public Administration Act.

**Re. Section 33**
**Exemption**

Exemption constitutes a decision by the authorities, normally as a result of an application, to accept a deviation from a regulation requirement. Deviation in this connection denotes a discrepancy between selected solutions and regulation requirements.

Application for exemption should be filed if one intends to apply a solution different from the one referred to by a specific regulation requirement, or a solution which does not meet the level required by the regulations.

Applications for exemption, if any, should as a rule contain:
a) a list of the provisions from which exemption is sought;
b) an account of the particular reasons for why an exemption is necessary or reasonable;
c) an account of the internal procedure of the enterprise in dealing with the exemption issue;
d) an account of the deviation and its planned duration;
e) an account of measures, if any, to compensate for the deviation, in full or in part;
f) an account of measures, if any, to correct for the deviation, if the deviation is of a temporary nature.

**Re. Section 34**
**Penal provision**

No comments.

**Re. Section 35**
**Entry into force and transitional provisions**

In a material sense these regulations mainly constitute a continuation of previous legislation. The regulations do not represent any increased stringency which necessitates exemptions from entry into force or transitional arrangements.

# DECC MEASUREMENT GUIDELINES – ISSUE 8 (2012)

**Douglas Griffin, U. K. Department of Energy & Climate Change**

## 1 INTRODUCTION

The DECC Measurement Guidelines have been updated and substantially re-written. Issue 8 was published in July 2012, superseding the previous (2003) issue.

These Guidelines provide Operators with details of DECC's expectations in the variety of scenarios under which fiscal measurement of hydrocarbons may take place in the upstream sector of the UK oil and gas industry.

This paper highlights some of the principal points of interest in the new document. The full document is available at the DECC website; at the time of writing the relevant URL is: http://og.decc.gov.uk/assets/og/ep/fields/4824-measurement-guidelines-v8.pdf .

## 2 REGULATORY ORGANISATION

The Department of Energy & Climate Change (DECC) was formed in October 2008, with the merger of the Energy Group from BERR (formerly DTI) and the Climate Change Group from DEFRA.

Responsibility for the regulation of non-safety-related aspects of the UK upstream oil and gas industry lies with DECC's Energy Development Unit (EDU), with offices in Aberdeen and London. Within EDU there are two branches:

- Licensing, Exploration and Development (LED);
- Offshore Environment & Decommissioning (OED).

Details of the responsibilities of each branch can be found on the DECC website.

### 2.1 Regulation of Fiscal and Environmental Measurement

Responsibility for the regulation of fiscal oil and gas measurement lies with the Petroleum Measurement and Allocation Team, which is part of LED.

The regulation of offshore environmental measurement (such as produced water metering or fuel and flare measurements required by the EU Emissions Trading Scheme (EU-ETS) is the responsibility of OED.

Onshore environmental measurements are regulated by the Environment Agency (in England and Wales) and the Scottish Environment Agency (in Scotland).

### 2.2 Petroleum Production Regulations

Operators of fields in the UK and on the UK Continental Shelf (UKCS) are granted a Petroleum Production License. This contains the 'Measurement Model Clause', which states that

> *"The licensee shall measure or weigh by a method or methods customarily used in good oilfield practice and from time to time approved by the Minister all petroleum won and saved from the licensed area."*

DECC's expectations with regard to what constitutes 'good oilfield practice' are set out in the document 'Guidance Notes for Petroleum Measurement – for Systems Operating Under the Petroleum Production Regulations', more commonly referred to as the 'DECC Measurement Guidelines'.

The Guidelines have been fully revised and were published in draft form during the first half of 2012. Following a 3-month consultation period, Issue 8 of the Guidelines officially came into force on 1st July 2012.

## 3 MEASUREMENT APPROVAL PROCESS (Chapter 2)

The approval process for new fiscal measurement systems, or for changes to existing ones, is managed via a procedure known as 'Petroleum Operations Notice No. 6', or 'PON 6'. The purpose of this procedure is to arrive at an agreed method of measurement for the given field in advance of its design and construction. The level of information required by DECC varies depending on the size of the field(s) concerned, but the procedure to be followed is the same in all cases.

Chapter 2 of the Guidelines goes into the PON 6 procedure in some detail. The document stresses the point that the method of measurement for a particular field is of fundamental importance to the field development strategy, and should be agreed at as early a stage as possible.

At this stage the discussions are fairly high-level in nature. A variety of measurement approaches are possible, which form the following hierarchy (in descending order of measurement uncertainty):

- Continuous, single-phase measurement of each phase, post separation, in dedicated meter runs designed to minimise measurement uncertainty.
- Continuous, nominally single-phase measurement of each phase on the oil, gas and water off-takes of a dedicated separator.
- Continuous multiphase measurement via a dedicated multiphase flow meter, installed either topsides or subsea.
- Intermittent, nominally single-phase measurement of each phase on the oil, gas and water off-takes of a test separator, with interpolation of the flow rates of each phase during the periods between these 'well tests'.

These approaches translate approximately into the classes of measurement defined in Chapter 3 of the Guidelines.

DECC shall always seek to achieve the optimal measurement solution in terms of balancing OpEx and CapEx costs against the increased financial exposure resulting from increased measurement uncertainty.

In many cases the likely measurement solution is clear from the outset, but where the decision is marginal DECC may require the Operator to carry out a cost-benefit analysis in order to identify the optimal approach.

Once the optimal approach has been identified and agreed, the detailed design of the measurement system may proceed.

Once the system is operational, the agreed method of measurement may not be changed without the prior written consent of DECC; in such cases a new PON 6 process is likely to be required.

## 4 GENERAL DESIGN CONSIDERATIONS (Chapter 3)

This chapter sets out some of the considerations that typically form part of the PON 6 discussions.

Essentially, at the design stage the question reduces to whether or not the field economics will support separation and dedicated processing of the fluids prior to their measurement and export. Once the likely fluid characteristics are clear (e.g. 'single phase', 'wet gas'), it will be clear which of the measurement approaches are realistically achievable.

The following table, which defines the possible measurement classes, is reproduced from p. 20 of the Guidelines.

**Table 1 – Measurement Approaches**

| Class of Measurement | Characteristics | Typical Applications |
|---|---|---|
| Single-Phase | Continuous measurement. Single-phase (i.e. post separation) in dedicated meter runs designed to minimise measurement uncertainty.<br><br>This is the only class of measurement with clearly-defined uncertainty limits; by consensus these are ±0.25% (dry mass) for liquid and ±1.0% (mass) for gas. | Export system from production platform.<br><br>Gas import system. |
| Production Separator Measurement | Continuous measurement.<br><br>Nominally single-phase measurements on the gas, oil and water off-takes of a production separator. However, more than one phase may be present during periods of process instability.<br><br>The separator may be operated in 2-phase mode, with water content of the oil off-take determined via sampling or via on-line water-cut meter. This will generally result in a higher measurement uncertainty than 3-phase operation. | Marginal field developed across pre-existing production platform. |
| Multiphase and Wet Gas Measurement | Continuous measurement.<br><br>Two or three phases measured simultaneously in a single meter.<br><br>Note: 'Wet gas' applications may be considered as a subset of multiphase measurement.<br><br>The meter may be located topsides or subsea. The measurement uncertainty will be similar in either case, but maintenance activities will be considerably more expensive in the latter. | Marginal field developed across pre-existing production platform, where economic or space constraints do not permit the use of a dedicated separator.<br><br>New minimal facilities installation. |
| Flow Sampling | Intermittent measurement.<br><br>Periodic, nominally single-phase measurements on the gas, oil and water off-takes of a test separator. However, more than | Marginal field developed across pre-existing production platform, where economic or space constraints do not permit the use of a dedicated separator. |

| | | |
|---|---|---|
| | one phase may be present during periods of process instability.<br><br>The intermittent nature of the measurement results in a higher measurement uncertainty than would be obtained with a dedicated production separator.<br><br>Operation of the test separator in 2-phase mode will increase the measurement uncertainty further. | Note the similarity to the multiphase scenario. All other factors being equal, DECC will normally prefer the multiphase option since the additional uncertainties around well-testing (arising from the intermittent nature of the measurements) are thereby avoided. |
| Inferential Measurement | Indirect measurement.<br><br>Includes 'By Difference' measurement.<br><br>Various techniques possible – uncertainty will depend on the application-specific factors. | Where none of the above options represent the optimal measurement solution. |

The document stresses the need to take account of life-of-field exposure when considering aspects of metering system design.

## 5 GENERAL OPERATIONAL CONSIDERATIONS (Chapter 4)

In recent years there have been significant improvements in the stability of secondary instrumentation, and in the ability to interpret the information provided by primary and secondary instrumentation – so-called 'diagnostic' information. As such, DECC considers that the time has come to completely re-examine the standard approach to maintenance strategy, which still tends to be 'time-based'. This is reflected in the a new section of the Guidelines (4.1), in which alternative methods are proposed – 'risk-based' and 'time-based'.

Essentially, risk-based maintenance requires the Operator to present, for a given element of the measurement station, an assessment of the likely 'worst-case' error that could reasonably be expected to occur over a proposed period of time. The financial exposure during this period may be calculated (based on the impact of such an error on the overall flow measurement) and compared with the cost of removal and recalibration. Provided the exposure is low compared with the calibration cost, DECC is likely to agree to the proposed interval between calibrations. Worked examples of such calculations are presented in Appendix 4.1 of the Guidelines.

Condition-based strategies propose to continually monitor key components of the measurement station, removing and recalibrating devices only when these show signs of having drifted from their calibrated conditions. Condition-based strategies are still relatively little used. One reason for this is that it is not always possible to relate drift in diagnostic parameters to actual measurement error; as such the decision as to whether or not intervention is required is not always clear cut. However, there is great potential for this technique to be usefully combined with a 'risk-based' method; the use of 'diagnostic' information may allow the Operator to reasonably reduce the estimate of the 'worst-case' error, so that the interval between calibrations may be extended.

As well as maintenance strategies, this section of the document contains expanded guidance on DECC's expectations with regarding record-keeping, and on DECC's approach to managing short- and medium-term deviations from the agreed method of measurement via a system of dispensations.

## 6 SINGLE PHASE LIQUID HYDROCARBON MEASUREMENT (Chapter 5)

The document has been updated to reflect significant changes in DECC's approach in a number of key areas.

### 6.1 Prover Calibration

Following the presentation of new information on prover calibration uncertainty at the 2009 NSFMW [1], DECC has formally revised the year-to-year repeatability requirements for prover calibration. (Sections 5.6.3 and 5.6.4 of the Guidelines refer.)

The expected year-to-year repeatability is now ±0.2% for calibrations using water, and ±0.4% where the calibration medium is crude oil or diesel.

### 6.2 Densitometer Calibration

In the light of the recommendations of a JIP on traceable density measurement (the results of which have been presented at successive NSFMW events, e.g. [2]), DECC has updated its guidance on densitometer calibration. (Sections 5.10.3 and 5.10.4 of the Guidelines refer.)

The new densitometer procedures require the calibration to take place at simultaneously elevated conditions of pressure and temperature on three calibration fluids which have been fully characterised on NEL's standard densitometer as part of the JIP. The calibration costs are increased compared to the previous method, but remain small when compared with typical financial exposure.

Work is in progress to confirm whether, as seem likely, calibration on two fluids gives an acceptable level of measurement uncertainty. DECC's guidance in this area will be reviewed correspondingly.

### 6.3 Sampling and Analysis

There is expanded guidance on DECC's expectations with respect to sampling and analysis and sampler performance (Sections 5.11.1 to 5.11.7 of the Guidelines refer).

## 7 SINGLE-PHASE GASEOUS HYDROCARBON MEASUREMENT (Chapter 6)

The document has been updated to reflect significant changes in DECC's approach in a number of key areas.

### 7.1 Differential Pressure Diagnostics

For differential pressure devices the document encourages the use of diagnostic measurements (demonstrated at successive NSFMW events, e.g. [3]) to extend the interval between successive inspections of the primary element (Section 6.7.7 of the Guidelines refers).

### 7.2 Condition-Based Maintenance of Gas USFMs

Detailed guidance is now presented in the area of condition-based maintenance (CBM) strategies for gas ultrasonic flow meters. This guidance is based on a consultation carried out by DECC during the first half of 2011, culminating in a manufacturers' session held in Aberdeen in June 2011. Sections 6.8.12 through 6.8.19 of the Guidelines refer.

As stated above, there is considerable potential to used condition-based maintenance to extend the interval between successive recalibrations as part of an overall 'risk-based' maintenance strategy. To date, DECC has only received one proposal for a genuine CBM strategy, in which the meters are potentially left in service indefinitely. The methodology by which acceptance was gained has been detailed in a previous NSFMW paper [4].

### 7.3 Pressure and Temperature Compensation for Gas USMs

A clear statement is made to the effect that calculations used to correct USFM calibration from 'reference' to 'in-service' conditions of pressure and temperature must be traceable and auditable.

Reference is made to an important paper from the 2008 NSFMW [6].

## 8 MULTIPHASE MEASUREMENT (Chapter 8)

The following table, which lists the typical applications in which multiphase flowmeters (MPFMs) are used in fiscal measurement applications, is reproduced from p. 62 of the Guidelines:

**Table 2 – Multiphase Applications**

| Application | MPFM Verification Method | Comments |
|---|---|---|
| MPFM topsides on 'host' facility, measuring all wells from a single 'satellite' field. | Comparison of MPFM with test separator.<br>Relatively straightforward in view of proximity of MPFM to test separator. | Allocation to satellite field relatively straightforward. PVT data required periodically; frequency higher where individual well characteristics believed to be significantly different. |
| MPFM subsea, measuring all wells from a single satellite field. | Comparison of MPFM with test separator. Relatively complex comparison in view of significantly different process conditions at MPFM/Test Separator, and in view of distance between these. Procedures must take account of possibility of slugging in flow line, etc. | Allocation to satellite field relatively straightforward. PVT data required periodically; frequency higher where individual well characteristics believed to be significantly different. *However, in practice it may be difficult or impossible to update initial PVT data.* |
| MPFM subsea, measuring all wells from more than one satellite field. | Comparison of MPFM with test separator.<br>Relatively complex comparison in view of significantly different process conditions at MPFM/Test Separator, and in view of distance between these. Procedures must take account of possibility of slugging in flow line, etc. | Highly complex allocation issues.<br>At least one MPFM manufacturer offers the possibility of a 'switching' facility whereby individual wells or groups of wells may be flowed separately through the MPFM. In this case, field allocation may be carried out as in #2 above.<br>PVT data required periodically; frequency likely to be higher than in #2 above, since fluid characteristics likely to show greater variability. *However, in practice it may again be difficult or impossible to update initial PVT data* |

New expanded guidance is presented on:

- meter selection;
- meter calibration/verification (requirements for static and dynamic testing, both onshore and offshore)

This section of the guidelines refers heavily to previous NSFMW papers (e.g. [6]).

It is recognised that sampling of multiphase fluids is a particularly important area, since representative compositional data is likely to be required both for the successful operation of the MPFM and also to correct the phase flowrates to standard conditions for verification or allocation purposes. The current lack of Standards in this area is acknowledged.

A summary of DECC's requirements with respect to the use of MPFMs in fiscal applications is presented in section 8.10.

## 10 WET GAS FLOW MEASUREMENT (Chapter 9)

The guidelines have been updated to reflect recent advances in wet gas flow measurement. Reference is made to a recent NSFMW paper [7] regarding the use of orifice plate meters in wet gas applications (section 9.5 of the Guidelines refers).

The use of a new correlation (presented at the 2009 NSFMW [8]) is now recommended for use with Venturi meters. This correlation covers a wider range of meter parameters and wet gas conditions than any of its predecessors. However, to date DECC has not received any proposals to use this correlation. One possible reason is that the correlation may not yet have been implemented in commercially-available flow computers.

A summary of DECC's requirements with respect to the use of MPFMs in fiscal applications is presented in section 9.10 of the Guidelines.

## 11 SEPARATOR & TEST SEPARATOR MEASUREMENT (Chapters 7 & 10)

Two separate chapters of the Guidelines deal with separator measurement. The technologies which may be employed and the associated measurement challenges are similar in each case , although the challenges are likely to be more extreme in the case of a test separator application.

Dedicated separators are commonly used in fiscal applications (see Table 1 above). The main difficulties here are associated with ensuring that gas breakout and/or liquid carry-over do not occur, that is to say that process design plays a critical role. Where process separators are 'promoted' to fiscal duty following the development of a new field across pre-existing infrastructure, the scope to follow best design practice may be limited within the financial constraints of the project.

Test separators may be used either directly in 'flow sampling' applications (as defined in Table 1) or in the verification of MPFMs or wet gas meters in fiscal service.

## 12 FUTURE ISSUE OF GUIDELINES

The next issue of the DECC Guidelines is planned for July 2013; annual releases are planned thereafter. The document is normally published in draft form during a three-month period during which feedback is actively invited.

DECC is very happy to receive feedback on the existing document at any time and considers the co-operation of Industry to be critically important in keeping the Guidelines up-to-date and relevant to current practice.

Comments should be addressed to the author at douglas.griffin@decc.gsi.gov.uk.

## 13 REFERENCES

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