DEPARTMENT OF ENERGY & CLIMATE CHANGE

DECC

Licensing, Exploration & Development

Guidance Notes for Petroleum Measurement

Issue 8

For systems operating under the Petroleum (Production) Regulations

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Main Contents

Full Table of Contents

1 INTRODUCTION

1.1 The Department of Energy and Climate Change (DECC)

DECC was formed on 3rd October 2008 with the merger of the Energy Group from BERR (formerly DTI) with the Climate Change Group, previously part of the Department of Environment, Food & Rural Affairs (DEFRA).

In these Guidelines the term 'DECC' is routinely used to refer both to the present organisation and, where relevant, its predecessors DTI and BERR.

Responsibility for the regulation of non-safety-related aspects of upstream Oil & Gas Industry in the UK lies with the Energy Development Unit (EDU) of DECC. This is based in Aberdeen and London.

Within EDU, there are 2 branches:

- Licensing, Exploration and Development (LED)
- Offshore Environment Division (OED)

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

Contact details and information on the organisation of responsibilities within the team may be accessed on-via the DECC Oil and Gas website (http://og.decc.gov.uk/); at the time of writing the specific URL is:

http://og.decc.gov.uk/en/olgs/cms/explorationpro/meas_of_pet/meas_of_pet.aspx

The regulation of offshore environmental measurements (such as produced water metering or fuel and flare measurements required by the EU-ETS) is the responsibility of DECC's Offshore Environment Division (OED). Contact details for OED are available via the following URL:

http://og.decc.gov.uk/en/olgs/cms/environment/environment.aspx

The regulation of onshore environmental measurements is the responsibility of the Environment Agency (for England & Wales) and the Scottish Environment Protection Agency (for Scotland).

1.2 Rationale for Measurement Guidelines

In common with its predecessor organisations (DTI and BERR), DECC remains committed to maximising the economic return to the UK of its hydrocarbon resources. Apart from the indirect benefits (the oil and gas industry accounts for one sixth of all UK investment, and supports some 450,000 jobs) the direct financial benefits from the fiscal regime are considerable, currently running at around £8bn p.a. This revenue is calculated on the basis of figures produced by measurement systems lying within the remit of these Guidelines.

Figure 1 contains a graph showing the UK government revenue from oil and gas production during 1976-2010. This is available on-line at the DECC website; at the time of writing at the following URL:

http://og.decc.gov.uk/assets/og/ep/appendices/UKCS_Tax_Chart.pdf

The purpose of this document is to provide Operators with guidance on DECC's expectations as to what constitutes 'Good Oilfield Practice', as required by the Measurement Model Clause of an Operator's Petroleum Production License, for the full range of fiscal measurement scenarios that are likely to be encountered in practice.

1.3 The UK Fiscal Regime

At the time of writing, the following link provides guidance on the status of the UK upstream oil taxation regime:

http://www.hmrc.gov.uk/manuals/otmanual/index.htm

1.3.1 Petroleum Revenue Tax (PRT)

Petroleum Revenue Tax (PRT) is administered by HM Revenue & Customs (HMRC) Large Business Service - Oil & Gas Sector (LBSOG) – formerly the Oil Taxation Office or 'OTO'. PRT seeks to tax a high proportion of the economic rent (super-profits) from the exploitation of the UK's oil and gas. PRT is a field-based tax: in general, the costs of developing and running a field can only be set against the profits generated by that field. Any losses, e.g. arising from unused expenditure relief, can be carried forwards or backwards within the field indefinitely. There is also a range of reliefs, including:

- oil allowance - a PRT-free slice of production
- supplement - a proxy for interest and other financing costs
- Tariff Receipts Allowance (TRA) - participators owning assets, for example pipelines, relating to one field will sometimes allow participators from other fields to share the use of the asset in return for the payment of tariffs, and TRA relieves some of the tariffs received from PRT
- exemption from PRT for gas sold to British Gas under a pre July 1975 contract
- cross-field relief for research expenditure

PRT is currently charged at 50% on profits after these allowances. For a limited period safeguard relief then applies to ensure that PRT does not reduce the annual return in the early years of production of a field to below 15% of the historic capital expenditure on the field.

PRT was abolished on 16 March 1993 for all fields given development consent on or after that date. This was part of a package of PRT reforms which also included the reduction of the rate of PRT from 75% to 50% and the abolition of PRT relief for Exploration and Appraisal expenditure.

1.3.2 Ring Fence Corporation Tax (RFCT)

Ring Fence Corporation Tax (RFCT), also administered by the LBSOG, is the standard corporation tax that applies to all companies with the addition of a 'ring fence'. The ring fence is designed to ensure that corporation tax on profits from oil extraction activities are paid in full as the profits accrue, undiluted by any losses or any other form of relief arising from any other business activities whether in the UK or elsewhere. The ring fence imposes restrictions, for example on excessive interest payments, to achieve this.

Most capital expenditure on oil exploration, field development and decommissioning activities in the North Sea qualifies for a 100% capital allowance in the year it is incurred.

The rate of CT is currently 30%. The reduction of the CT rate and the reform of capital allowances introduced in 2007 and effective from 1 April 2008 do not apply to RFCT.

1.3.3 Supplementary Charge (SC) on Ring Fence Trades

On 17 April 2002 a Supplementary Charge was introduced, payable on profits from a ring fence trade. These profits are the same as for RFCT but with no allowance for any financing costs.

Between 17 April 2002 and 1 January 2006 the SC was charged at 10%. From 1 January 2006 this was raised to 20%. From 24th March 2011 this was raised to 32%.

1.3.4 Royalty - abolished from 1 January 2003

Royalty was charged at 12.5% of the gross value of oil and gas won and saved in a particular licensed area, less an allowance for certain costs.

1.3.5 Interaction of PRT, RFCT and SC

RFCT and SC are charged on a company's ring fence trade CT profits after a deduction for any PRT.

The regime which applies to any particular oil field depends on the date on which it received development consent:

- Fields which received development consent before 16 March 1993 are subject to PRT, RFCT and SC. Where these fields received development consent before 1 April 1982 they would also have been liable to royalty until 31 December 2002

- Fields which received development consent on or after 16 March 1993 are subject only to RFCT and SC

Current marginal rates of tax are:

- RFCT and SC - 62%

- PRT, RFCT and SC - 81%

1.3.6 Field Allowances

There exist allowances for the following categories of field:

- Small field

- High Pressure / High Temperature (HP/HT)

- Heavy Oil

- Deep water

Details of these allowances are available here:

http://www.hmrc.gov.uk/manuals/otmanual/ot21415.htm

1.4 Applicability of Measurement Guidelines

This document contains Guidelines for Licensees and Operators in Great Britain, the territorial waters of the United Kingdom and on the UK Continental Shelf (UKCS).

The Guidelines are intended for use in the design, construction and operation of measurement systems for which the approval of the Secretary of State is required under the Measurement Model Clause of the Petroleum (Production) Act 1934. The Measurement Model Clause is reproduced in Appendix 1.1.

Essentially, these Guidelines relate to measurement systems used to determine quantities of petroleum won and saved from licensed areas (fields) both onshore and offshore in the UK.

The Guidelines should be interpreted as representing general minimum requirements. They should not be viewed as prescriptive

The Guidelines routinely refer to the 'Operator' and the 'Licensee'. While the legal responsibility to meet the terms of the Measurement Model Clause rests with the Licensee, DECC expects Operators to similarly adhere to the principles of 'good oilfield practice' and the two terms are used here interchangeably.

1.5 Guidance and Standards

Throughout these Guidelines there are references to well-known standards documents published by the International Standards Organisation (ISO), the British Standards Institute (BSI), the Energy Institute (EI), the Norwegian Society for Oil and Gas Flow Measurement (NFOGM) and others. A list of useful standards is provided for reference at the end of each chapter.

These Guidelines also make extensive reference to papers published at the North Sea Flow Measurement Workshop (NSFMW). These papers represent an invaluable source of practical guidance that may not otherwise be available for several years.

The proceedings of the NSFMW are to be made available at the websites of the organisers, Tekna (www.tekna.no) and NEL (http://www.tuvnel.com/).

1.6 'Fiscal' Measurement - Clarification

The use of the phrase 'fiscal metering' does not necessarily imply any particular expectation of the quality of the measurement concerned. The label 'fiscal' refers to the measurement system's service, not its quality.

In the present context, a 'fiscal' measurement station is any measurement station used to determine quantities of hydrocarbons won and saved from a licensed area (field), since this information will subsequently be used to determine government revenues. As indicated in Chapter 3 of these Guidelines, the level of uncertainty appropriate to fiscal service will vary from field to field, as a function of the economics of the particular field development.

1.7 Inspection Activities

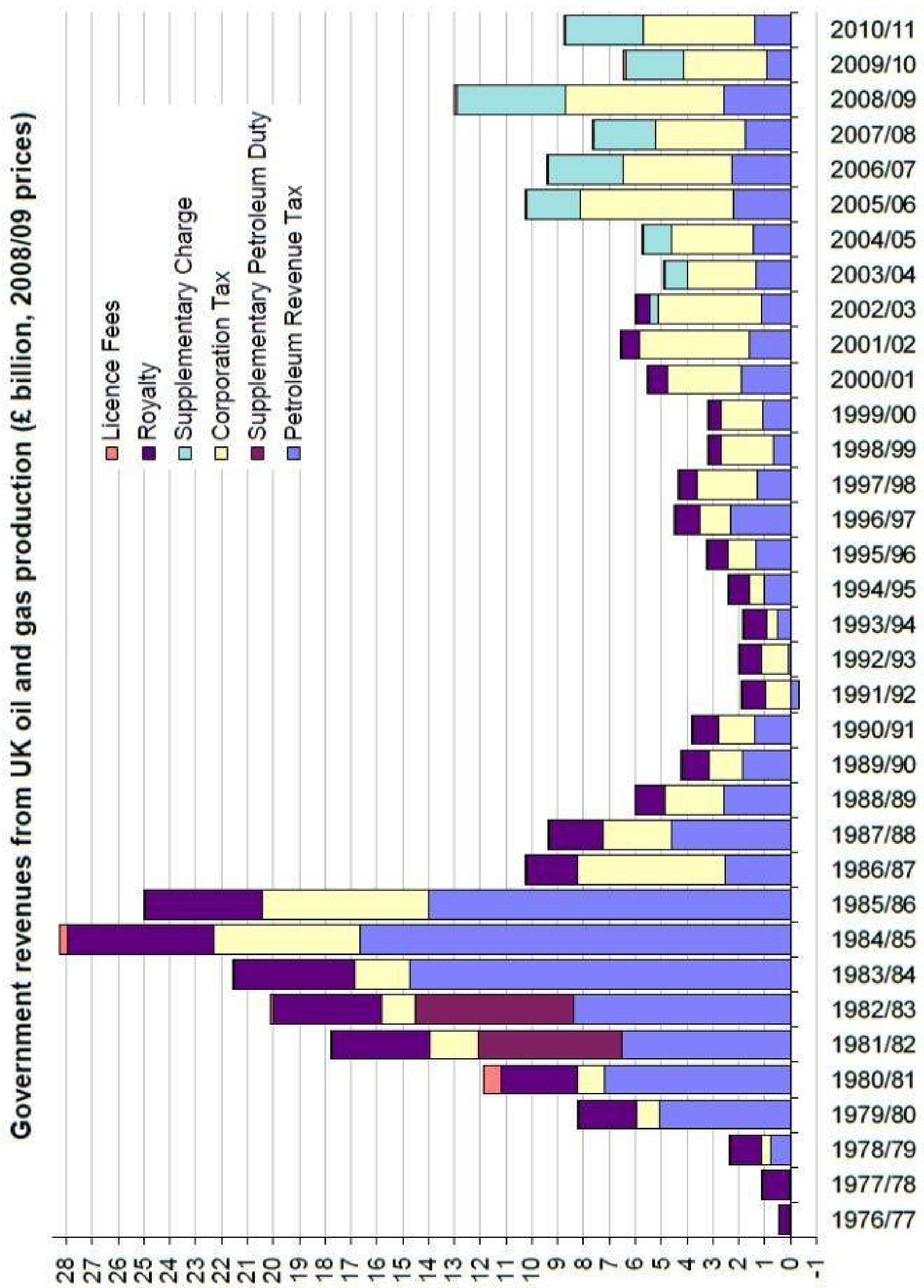
Each year DECC carries out a prioritised programme of inspections, the aim of which is to assess the extent to which the respective fiscal measurement stations are being operated in accordance with 'good oilfield practice'.

DECC shall normally give Operators a minimum of two weeks' notice of its intent to inspect a particular site.

Note that DECC has a Statutory Right of Access to inspect fiscal measurement stations, and as such shall only agree to Operators' requests to reschedule planned inspections in exceptional circumstances.

Following its inspections, any identified departures from normal practice shall be brought to the attention of the relevant Operators via an E-mail communication. Unless otherwise indicated, Operators are expected to respond within 3 weeks of the date of the E-mail from DECC. The response should include details of any remedial action already taken and the timeframe for the resolution of any issues that are still outstanding.

Figure 1 – UK GOVERNMENT REVENUES FROM OIL AND GAS PRODUCTION



(Source: http://og.decc.gov.uk/assets/og/ep/appendices/UKCS_Tax_Chart.pdf)

Appendix 1.1 - The Measurement Model Clause

As printed in The Petroleum (Production) (Seaward Areas) Regulations 1988 and subsequent regulations.

(1) 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.

(2)* If and to the extent that the Minister so directs, the duty imposed by paragraph (1) of this clause shall be discharged separately in relation to petroleum won and saved -

(a) from each part of the licensed area which is an oil field for the purposes of the Oil Taxation Act 1975,

(b) from each part of the licensed area which forms part of such an oilfield extending beyond the licensed area, and

(c) from each well producing petroleum from a part of the licensed area which is not within such an oilfield.

(3)* If and to the extent that the Minister so directs, the preceding provisions of this clause shall apply as if the duty to measure or weigh petroleum included a duty to ascertain its quality or composition or both; and where a direction under this paragraph is in force, the following provisions of this clause shall have effect as if references to measuring or weighing included references to ascertaining quality or composition.

(4) The Licensee shall not make any alteration in the method or methods of measuring or weighing used by him or any appliances used for that purpose without the consent in writing of the Minister and the Minister may in any case require that no alteration shall be made save in the presence of a person authorised by the Minister.

(5) The Minister may from time to time direct that any weighing or measuring appliance shall be tested or examined in such a manner, upon such occasions or at such intervals and by such persons as may be specified by the Minister’s direction and the Licensee shall pay to any such person or to the Minister such fees and expenses for test or examination as the minister may specify.

(6) If any measuring or weighing appliance shall upon any such test or examination as is mentioned in the last forgoing paragraph be found to be false or unjust the same shall if the Minister so determines after considering any representation in writing made by the Licensee be deemed to have existed in that condition during the period since the last occasion upon which the same was tested or examined pursuant to the last foregoing paragraph.

** Paragraphs (2) and (3) are not incorporated into Licences which contain the model clauses in Schedule 6 to the Petroleum (Production)(Landward Areas) Regulations 1991.*

2 PETROLEUM OPERATIONS NOTICE 6 (PON 6)

2.1 Measurement Model Clause

The purpose of the PON 6 procedure is to establish an agreed Method of Measurement for a given field. The need for this arises from the Measurement Model Clause of the Petroleum Production License for the field, which contains the following statement:

"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."

The level of information required by DECC will vary depending of the significance of the field development under consideration. However, the procedure to be followed is the same in all cases.

2.2 Method of Measurement

DECC should be contacted as early as possible in the planning of a field development, in order that a Method of Measurement for that field may be agreed.

Measurement approaches may be regarded as following the following hierarchy (in ascending 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 options are described more fully in Chapter 3 of these Guidelines.

The optimal measurement solution is one where the need to maintain a low measurement uncertainty is balanced against the economics of the field development in question. DECC will always seek to achieve such a balance in the interests of encouraging the development of the UK's remaining hydrocarbon reserves.

2.3 Initial Meeting

For a new field development, the Licensee should present its proposals to DECC at an initial meeting. From the above it should be clear that the measurement approach is fundamental to the nature of a field development. Therefore the meeting should take place at as early a stage as possible, and certainly prior to the submission of the Field Development Plan to DECC's Field Teams.

In considering the proposed measurement approach DECC will take account of the specific economic and technical aspects of the proposed field development. At this stage Licensees should provide the following information:

- The reserves and anticipated production profile of the field.
- A process schematic, indicating the location of the proposed metering and sampling points. Where 'satellite' fields are being considered, details of any space and weight constraints on the 'host' facility should be included.

- Details of the proposed measurement and allocation approach, including the metering and sampling technologies, along with an overall measurement uncertainty figure.

- Details of the proposed method and frequency of reverification of the metering technology. Where it is intended to adopt a 'condition-based monitoring' strategy, this needs to be considered at the design stage as it may necessitate the use of additional measurement points and/or dual instrumentation.

DECC may require Licensees to carry out a cost-benefit analysis so that the optimal method of measurement may be determined.

2.4 Formal 'Non-Objection' from DECC

Once the measurement approach has been agreed, a formal 'non-objection' to the proposed Method of Measurement will be issued, and the detailed design and construction of the measurement and sampling system may proceed.

2.5 Supporting Documentation

Prior to the start-up of the field, the Licensee should provide DECC with a Functional Design Specification for the agreed measurement approach. This should include, as a minimum:

- Piping & Instrumentation Diagrams showing the dimensions and configuration of the pipework immediately upstream and downstream of the metering and sampling systems

- Details of the calculations that will be used in determining measured quantities.

- The model of flow computers, supervisory computers and associated software that it is proposed to use.

DECC may also require the Licensee to submit the following for review:

- Operating and/or Calibration procedures for the measurement station, including proposed frequencies for the recalibration of critical flow elements

- An uncertainty analysis, demonstrating that the uncertainty level agreed in 2.3 above is achievable.

2.6 Testing and Calibration Activities

Prior to its installation and on-site commissioning, the Operator must be able to demonstrate to DECC that the critical elements of a fiscal measurement station are fully operational, with all necessary functionality and all relevant calculations being performed to within the required tolerances. The responsibility for ensuring that the systems are correctly tested at this stage lies with the Operator.

The following procedure should be followed:

a) Prior to the start of the Factory Acceptance Test, the Operator must designate within their organisation a responsible authority who will co-ordinate the testing procedure. The Operator should also indicate to DECC the identity of the representative(s) that it intends to have present during the testing procedure.

b) Once the correct operation of the system has been demonstrated to the Operator's own satisfaction, the Operator should prepare a report summarising the results of the test procedure, highlighting any problems that were encountered. This report should be submitted to DECC for review. Subject to the result of its review, DECC may then require selective additional testing to be carried out.

DECC should also be invited to the calibration of primary flow elements.

DECC requires at least 2 weeks' notice for its attendance at all critical testing and calibration events.

2.7 Changes to an existing Method of Measurement

Where a Licensee intends to change an existing Method of Measurement*, a formal proposal should be made to DECC at as early a stage as possible. Licensees should provide DECC with the following information:

- The justification for the proposed change in the Method of Measurement.
- A process schematic, indicating any proposed changes to the location of the metering and sampling points.
- Details of the proposed new Method of Measurement, including the new metering and/or sampling technologies, along with an overall measurement uncertainty figure for the new system.

Depending on the degree to which the new Method of Measurement differs from the previous one, DECC may require the Licensee to go through stages 2.2 to 2.4 above, as for new field development.

** for example, where it is proposed to change the use of:*

- The primary measurement element (e.g. changing from turbine meter to Coriolis meter).
- The flow computer used to calculate flow rate through the primary measurement element.
- Any Standards used in the calculation of measured quantities (e.g. the version of ISO 5167).

3 GENERAL DESIGN CONSIDERATIONS

3.1 Measurement Approach

As indicated in 2.2 and 2.3 above, the Method of Measurement for a particular field is fundamental to the nature of the field development, and must be determined at as early a stage as possible.

This Section of the Guidelines describes the characteristics of the typical measurement approaches that are adopted in North Sea applications, and indicates the levels of uncertainty that are potentially achievable with each. (Note the remarks in 3.4 below.)

3.1.2 Rather than 'fitting' a measurement approach to a particular field development, it is more appropriate to consider at the design stage the economics of the field and the standard of measurement that will thereby be supported. Essentially this reduces to whether or not the project economics will support separation and dedicated processing of fluids prior to their measurement and export. Once the likely fluid characteristics are clear (e.g. 'single phase', 'wet gas') it will then be clear which of the measurement approaches are realistically achievable.

DECC expects Licensees to adopt the best standard of measurement consistent with these economic considerations.

3.2 Life-of-Field Financial Exposure

While the cost of installing a high-quality measurement system is obvious, its associated benefits are often less well appreciated, especially in the light of the inevitable pressure to minimise CapEx at the design stage. Essentially, the design uncertainty sets a limit on any systematic bias that may exist (between calibrations) throughout field life. The higher the design uncertainty, the higher the resultant financial exposure.

Basic exposure calculations may be used to inform decisions at the design stage. The cost of investing money in a lower-uncertainty measurement system may then be weighed against the benefit in terms of the reduction in financial exposure. (See 'Maintenance Strategy', below.)

The level of detail will vary from case to case, but DECC will normally require the Licensee to carry out such an exercise before agreeing to a proposed Measurement Approach.

3.2.1 Whatever the measurement approach, the target uncertainty will only be met if the appropriate maintenance and calibration activities are carried out. It is by no means always the case that a system designed to operate at an uncertainty of ±5% requires less maintenance than a system designed to achieve ±0.25%. The higher uncertainty of the former may merely be a reflection of the more challenging fluid conditions.

3.3 Classes of Measurement

For the purpose of these Guidelines, the following measurement classes are defined:

Class of Measurement	Characteristics	Typical Application
Single Phase Measurement	Continuous measurement. Single-phase (i.e. post separation) in dedicated meter runs designed to minimise measurement uncertainty. 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. Gas import system.
Production Separator Measurement.	Continuous measurement. 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. 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. Two or three phases measured simultaneously in a single meter. Note: 'Wet gas' applications may be considered as a subset of multiphase measurement. 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. New minimal facilities installation.
Flow Sampling.	Intermittent measurement. Periodic, nominally single-phase measurements on the gas, oil and water off-takes of a test separator. However, more than one phase may be present during periods of process instability. The intermittent nature of the measurement results in a higher measurement uncertainty than would be obtained with a dedicated production separator. Operation of the test separator in 2-phase mode will increase the measurement uncertainty further.	Marginal field developed across pre-existing production platform, where economic or space constraints do not permit the use of a dedicated separator. 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. Includes 'By Difference' measurement. Various techniques possible – uncertainty will depend on the application-specific factors.	Where none of the above options represent the optimal measurement solution.

3.3.1 It may also have to be borne in mind that the fluid characteristics may change throughout the field life. For example, production from a dry gas field may become wet due to falling reservoir pressure, or the water cut of the oil produced from a field may increase to the extent that the measurement solution can no longer be considered a 'single phase' application. In such cases it may be necessary to establish review dates at which the agreed method of measurement will have to be reconsidered.

3.4 'By Difference' Measurement

3.4.1 DECC shall normally only consent to the use of 'by difference' measurement when it can be demonstrated that all other approaches are uneconomic, i.e. the reduction in exposure through the reduced measurement uncertainty that would result from the use of a direct measurement is not offset by the associated cost.

3.4.2 The uncertainty in the 'by difference' quantity depends on the relative proportion of the amount allocated 'by difference' to the amount measured directly. The smaller the proportion it forms, the larger the resultant uncertainty.

DECC may require Operators of such systems to carry out periodic uncertainty reviews to determine whether the consent condition in 3.4.1 is met.

3.4.3 The broad field-management need to maintain flow measurement uncertainty for individual wells to within ±10% shall also be considered by DECC when determining the acceptability of a proposal for 'by difference' measurement.

3.5 'Virtual' Metering

There exists a variety of techniques for estimating flow from individual wells, based on measurement of pressure and temperature at downhole, subsea and/or topside locations. These may be collectively termed 'virtual metering' solutions.

In view of their lack of traceability, such techniques are not regarded as sufficient as a Method of Measurement for a given field. However, they may be used in parallel with other technologies, so that the relevant models may be 'tuned' against traceable measurements. For example, they may be tuned against multiphase meters, with the aim of offering contingency measurement in the event of their failure. This may be a particularly important resource when the multiphase meters are located subsea.

3.6 Flow Computers and Supervisory Computers

3.6.1 Flow computers and supervisory computers used in the calculation and reporting of fiscally-measured quantities must be secure, and must display all relevant data to a resolution sufficient to ensure that it may be independently verified as having been calculated and/or entered correctly.

3.6.2 All calculation routines shall be verified at factory-acceptance tests (FAT) and site-acceptance tests (SAT) prior to their use in fiscal duties.

3.6.3 Any changes to the agreed versions of software must be implemented only after prior discussion with DECC. The software version numbers must be kept up to date to reflect any changes in the software and to preserve the audit trail.

3.6.4 Remote 'write' access to flow computers and supervisory computers must be strictly controlled. Remote write access events must be logged and a description of the work performed must be recorded in the relevant logbook.

4 GENERAL OPERATIONAL CONSIDERATIONS

4.1 MAINTENANCE STRATEGY

4.1.1 Introduction

Calibration is fundamental to the operation of any measurement system and the strategy to be adopted must be considered at the outset of its design. Without regular comparison to national standards, either directly or (more commonly) via an unbroken chain of transfer standards, it may be difficult or impossible to demonstrate the continued satisfactory operation of a measurement system.

4.1.2 Calibration

Calibration of primary and secondary instrumentation must be traceable to recognised national standards.

Where the facility exists, DECC shall normally require accreditation by UKAS or an equivalent overseas body.

Certification to UKAS or equivalent standards should not on its own be regarded as sufficient to ensure that the correct procedures are followed at a calibration.

Where primary flow elements are calibrated at remote facilities, Licensees must satisfy themselves that test procedures and operational set-up are appropriate for the meter under test. DECC may require Operators to demonstrate that such additional checks have been carried out.

4.1.4 Test Equipment

A set of transfer standards ('test equipment') must be maintained in order that routine calibrations on the primary and secondary instrumentation may be carried out on site. The test equipment must be dedicated to fiscal metering service, and adequate on-site storage for the test equipment must be provided.

Unless otherwise agreed with DECC, test equipment should be re-calibrated at yearly intervals. The calibration should be traceable to national standards, and the relevant calibration certificates should be available for inspection. This requirement does not apply to items of test equipment used for signal generation purposes (e.g. frequency generator).

Recalibration of primary and secondary instrumentation should take place in an appropriate environment, with adequate protection from the elements – this is especially important in exposed offshore modules.

4.1.6 Financial Exposure

It must be borne in mind at all times that calibration activities are not carried out for their own sake, but to safeguard against the continued presence of measurement bias.

Measurement bias in a fiscal system is significant since it will inevitably favour either the 'buyer' or the 'seller' of the product being measured. The financial exposure to either side is a function of the product of the potential magnitude of the bias and the period of time during which the bias may be present:

$$E = f(\delta\ \tau)$$

where E = financial exposure

δ = potential systematic bias

τ = potential duration of bias

To a large extent δ is determined by the design of the measurement system, i.e. by the measurement approach selected. Once δ has been effectively fixed, the value of E is effectively a function of τ. The management of this situation may be approached in three fundamentally different ways, via strategies that shall for the purposes of this document be labelled 'Time-Based', 'Risk-Based' and 'Condition-Based' methods. These are discussed in the following paragraphs.

4.1.7 Time-Based Maintenance

In the early stages of the development of the UK Sector of the North Sea, the interval between successive calibrations of measurement instrumentation was set on an effectively arbitrary time-elapsed basis. Maintenance activities were initially scheduled at monthly and quarterly intervals on gas and liquid measurement systems respectively. Subject to the demonstration of a satisfactory level of stability, these frequencies were relaxed on an instrument-by-instrument basis following discussion with the Regulator and/or pipeline operator, where appropriate.

DECC accepts that such procedures are still written into many commercial pipeline agreements, and that there may be considerable practical difficulties involved in changing these practices. Nevertheless, Operators are strongly encouraged to consider abandoning this strategy in favour of a 'Risk-Based' or 'Condition-Based' approach.

4.1.8 Risk-Based Maintenance

A more sophisticated approach may be used to determine the appropriate frequency of calibration for any element of a measurement system. This 'risk-based' approach works by considering the total cost of the calibration activity, and weighing this against likely exposure, determined by estimating the maximum extent of δ that is likely to exist over a period τ.

The following stages are involved in this approach:

(i) The relevant flow rate is determined. For an individual meter, this would be the flow rate that passes through it. For an element of secondary instrumentation common to the entire metering station, the station flow rate would be the relevant figure.

(ii) A representative product value is applied to the flow rate determined in (i) to establish the relevant 'value flow rate'.

(iii) For the given element of the measurement station, an estimate is made of the likely maximum extent of any systematic bias in performance over the course of a given period of time. This figure should be based on the previous performance of the element whenever possible. For new elements, a conservative estimate may be made, based on the typical performance of other such devices.

(iv) The effect of the level of bias determined in (iii) on the value flow determined in (ii) should be established. This gives the effective exposure over a given period of time.

There are some important points to note at this stage:

- The value flow rate should be integrated over the same period of time as that during which the systematic bias may be expected to occur.
- The effect of the systematic bias on the value flow rate is not necessarily linear. For example, on an orifice plate metering station, a bias in density measurement of 0.1% would result in an overall flow rate error of 0.05%.
- The estimated exposure should be regarded as tending towards an over-estimate, since the systematic bias is likely to have increased to its maximum value over time.

(v) The exposure calculated in (iv) above is compared with the cost of a calibration to remove the systematic bias. The appropriate calibration frequency may be determined by balancing these two figures.

The above information, together with any supporting evidence for the assumptions made, should be made available to DECC for review

Two illustrative examples of the procedure are provided in Appendix 4.1. It will be seen from these that there is a certain amount of judgement required, and the appropriate period between calibrations is open to a certain amount of interpretation. Nevertheless, this method is certainly no more arbitrary than the practice of removing and recalibrating elements of a metering station at a pre-determined frequency, irrespective of the throughput of that station, and hence the financial exposure incurred as a result of undetected measurement error. The method proposed here seeks to compare all stations on a like-for-like basis by considering the economics involved.

4.1.9 Condition-Based Maintenance

If we again consider the exposure formula:

$$E = f(\delta\ \tau)$$

it will be seen that minimising τ will result in reduced financial exposure. This is the basic principle of condition-based monitoring systems. The aim is essentially to detect and if possible rectify any measurement bias as soon as it arises.

A number of different types of condition-based maintenance systems are possible:

(i) Instrumentation may be duplicated, with continuous comparison of the outputs. With such a strategy there is an obvious risk of common-mode error, and DECC will generally require to be satisfied that reasonable measures have been taken against this possibility.

(ii) Measurement may be duplicated using a different physical principle, with continuous comparison of the outputs. This method has the advantage of minimising the risk of common-mode error.

(iii) On-line 'diagnostic' tools may be used to continuously monitor the performance of the individual parameters, or of the measurement system as a whole. These may provide quantitative or qualitative information.

Where it is proposed to implement a condition-based monitoring system, the following points should be considered:

(i) The range of parameters to be monitored, and the strategy for monitoring their condition, must be set out and agreed in advance with DECC.

(ii) The monitoring system should be sensitive enough to detect a bias in the measurement of any parameter that is of sufficient magnitude to cause an unacceptably large change in the flow rate measurement of the station as a whole. In deciding whether a change is 'unacceptably large', it may be necessary to balance the perceived exposure against the cost of intervention, using the same method as in 4.1.8 above.

(iii) Ideally, the sensitivity of the overall flow rate measurement to a change in any individually-monitored parameter should be established. Where it is not possible to establish such a quantitative relationship, it may be possible to monitor the rate of change of each parameter, and to err on the side of caution by intervening whenever a statistically-significant deviation occurs.

(iv) A condition-based maintenance system requires the ability to intervene when necessary. Therefore, sufficient isolation for each critical element must be provided so that it may be removed without necessitating the shut-down of the entire measurement station.

4.2 Dispensation for Non-Standard Operational and/or Maintenance Procedures

During the operational life of a field, there may arise situations where it is not possible to maintain the measurement station to the previously-agreed standards without resorting to potentially very expensive intervention, up to and including a full process shutdown. In such cases, the need to maintain measurement integrity must be balanced against the cost of the required intervention.

Deviations from the agreed standards of operation and/or maintenance are managed by DECC via a system of dispensations.

4.3 Dispensation Requests

4.3.1 The Operator must contact DECC in writing as soon as it becomes clear that the previously-agreed standards cannot be maintained. (An initial telephone discussion may help clarify whether a dispensation is in fact required.) The following information should be provided;

(i) The reason for the deviation from normal operating and/or maintenance conditions.

(ii) The expected duration of the deviation.

(iii) An estimate of the cost that would be incurred by immediate intervention and remedial action.

(iv) Details of any measures taken to facilitate opportunistic remedial action, taking advantage of any unplanned shut-downs of sufficient duration to permit the necessary work to be completed.

The dispensation request should feature a unique reference number for tracking purposes.

4.3.2 After consideration of the information listed above, DECC shall advise the Operator in writing of the terms of any dispensation granted.

4.3.3 DECC must be informed once normal operating practice resumes so that the dispensation may be closed out.

4.3.4 Extensions to dispensations shall normally only be granted in exceptional circumstances, when it can be shown that all reasonable efforts have been made by the Operator to resolve the outstanding issues within the originally-agreed timeframe.

DECC must be contacted as soon as it becomes clear than an extension to a dispensation shall be required.

4.3.6 Operation beyond the date of expiry of an outstanding dispensation shall be regarded by DECC as a breach of the terms of the Operating License for the relevant field(s).

4.4 Mismeasurement Reporting

DECC must be informed in writing whenever a significant mismeasurement has been identified. (An initial telephone call may help to establish whether the quantity concerned should be regarded as significant.)

The following information should be provided:

(i) The reason for the mismeasurement.

(ii) The amount estimated to have been mismeasured.

(iii) The methodology used to determine the figure in (ii) above.

4.5 Records to be Maintained

The Operator shall maintain event logs and configuration records.

These records should be designed in order to allow an independent observer to determine the extent to which the metering station is operating normally, and also to aid in the retrospective calculation of any mismeasured quantities.

The use of electronic logbooks and automated configuration recording is encouraged.

4.5.1 Log Books

Metering station logbooks shall be maintained. Details of all non-routine and certain routine events (e.g. primary flow element calibrations) shall be recorded. Serial numbers of all equipment removed and installed should be recorded, along with the reason for change-out.

4.5.2 Configuration Listings

Operators should maintain up-to-date configuration listings of all parameters used in the fiscal calculation routines. Changes of manually-entered parameters should be recorded in a controlled document, with details of:

- The new value of the parameter
- The previous value of the parameter
- The reason for the change
- The date of the change.

4.5.3 Routine Calibrations

The Operator shall maintain secure records of all routine calibrations carried out on the measurement station. These records must be available for review by DECC.

APPENDIX 4.1 - RISK-BASED MAINTENANCE CALCULATION

Example 1

Prover base volume for a liquid measurement station with a typical daily throughput of 25,000 bbl/d. Over the previous 6 years the base volume has not experienced a shift greater than 0.01% during the 24-month period between each calibration. Total cost for base volume calibration is approx. £75k.

A period of 1 year is considered.

(i) Average expected flow rate over the period under consideration: 25,000 bbl/d.

(ii) Assumed oil price $80/bbl ≈ £50/bbl. Value flow rate ≈ £1.25m/day, or ≈£450m/year.

(iii) Given the previous history of the prover base volume, the maximum extent of any bias is likely not to exceed 0.01%.

(iv) The relationship between the prover base volume bias and the station flow rate is 1:1, i.e. 0.01% over 1 year ≈ £45k.

(v) Given the exposure (£45k per year) and the cost of calibration (£75k), an interval between calibrations of 3 years could reasonably be proposed.

Example 2

Gas ultrasonic meter, one of two operating on a newly-installed offshore metering station with a daily throughput of $2x10^6$ Sm^3/d. The expected cost of calibration of the ultrasonic meter, including transport of the meter to and from the offshore installation, is approx. £30k.

A period of 1 year is considered.

(i) Average expected flow rate through the meter over the period under consideration: $1x10^6$ Sm^3/d.

(ii) Assumed gas price £0.21/Sm^3. Value flow rate ≈ £210,000/day, or approximately £75m/year.

(iii) There is no 'in-service' history for this meter, but industry experience with this type and size of meter in offshore applications indicates that any systematic bias during the first 12 months of operation is not likely to exceed 0.3%.

(iv) The relationship between the meter bias and the station flow rate is 1:1, i.e. 0.3% over 1 year ≈ £225k.

(v) Given the exposure (£225k per year) and the cost of calibration (£30k) it seems reasonable that 3-4 calibrations are performed per year. Therefore an interval between calibrations of 3-4 months could reasonably be proposed.

5 SINGLE-PHASE LIQUID HYDROCARBON MEASUREMENT

5.1 INTRODUCTION

5.1.1 This section of the Guidelines is intended for use in the design of measurement systems for liquid petroleum that is single-phase in character.

For this condition to be met, the measurement station must be designed such that the liquid is held above its vapour pressure, with no significant risk of gas breakout at the meter.

The general principles contained in this section of the Guidelines may be used to inform the decision-making process in the design and operation of meters on separators, but it should be recognised that single-phase conditions may not always be guaranteed in such applications.

5.1.2 A substantial proportion of the liquid export metering systems in the UK sector of the North Sea are based on ‘conventional’ turbine meter and bi-directional prover loop systems with associated on-line density measurement and automatic sampling.

Many fields on the UKCS have now passed their production plateaux, and as flow rates decline the originally agreed Method of Measurement may no longer be appropriate, since there are often considerable difficulties associated with the operation of turbine meters and prover loops at flow rates considerably below their design maxima. In such cases there are often very good reasons for retro-fitting smaller metering systems that make use of master meters for reverification purposes. In addition, an increasing number of export systems have from the start made use of relatively new technologies such as ultrasonic or Coriolis meters.

This chapter contains guidance on the design, operation and reverification of metering systems in each of these scenarios.

5.2 Measurement Uncertainty

5.2.1 Unless otherwise agreed with DECC, systems designed to measure quantities exported into common transportation systems should be capable of demonstrating an uncertainty to within ±0.25% of dry mass.

5.2.2 The uncertainties for tanker offload systems shall be agreed with DECC on a case-by-case basis, following a review of the specific details of each system. Section 5.12 presents detailed guidance in this area.

5.3 Mode of Measurement

The measured quantity may be determined in either volumetric or mass units.

Oil is sold in volume units (barrels). For pipeline allocation purposes, mass measurement is normally essential since value derived from the sale is allocated to each contributing element on a mass basis, with some adjustment for quality.

Where the measured quantity is expressed in volume terms, this should be referred to standard reference conditions of 15°C and 1.01325 bar absolute.

Mass measurement may be achieved either by;

a) Measurement of volume flow rate and fluid density

b) Direct mass measurement

If method a) is preferred, the density must be referred to the conditions of temperature and pressure at the meter.

5.4 Volume Correction Factors

5.4.1 Liquid volume correction factors should be representative of the process fluid.

5.4.2 The density referral method should not introduce significant bias into the determination of mass flow rate.

Note - As a check, the densitometer density may be referred to standard conditions, and then back to densitometer conditions. The indicated density should agree with the original figure to within the agreed tolerance. This would normally be 0.001%, but in some circumstances – for example, where very high financial exposure is involved – DECC may insist on better agreement.

5.4.3 The values of K0, K1 and K2 used in the density referral method should be representative of the type of fluid being measured.

5.5 METERING STATION DESIGN – GENERAL CONSIDERATIONS

Metering stations should have a common inlet header and, if necessary, a common outlet header to ensure uniform conditions throughout the measurement station.

If product of different physical properties is produced by separate production trains and is not fully commingled before measurement then it may be necessary to have separate measurement stations for the differing fluids.

DECC does not normally permit the fitting of recirculation loops except in export systems featuring rapid tanker loading. Where a recirculation loop is to be used, provision must be made for the recording of non-export flows.

5.5.1 Standby Streams

Some maintenance activities (for example, the removal of the primary flow element from the meter stream) may necessitate the removal of a meter stream from service. Therefore, for continuous export systems at least one standby stream should be available when the meter station is operated at its nominal maximum flow rate.

Where export is not continuous (for example, where oil is produced to storage tank and then ‘batch’ exported via pipeline or shuttle tanker) maintenance activities may be scheduled to take place between periods of export. In such cases standby streams may not be necessary.

Operators should note that DECC will not accept the absence of a standby stream as justification for the postponement of maintenance activities.

5.5.2 Isolation of Critical Elements

The measurement station should be designed so that it is possible to safely remove individual elements from the system without necessitating the shut-down of the entire export system. This is particularly important where elements of the system must be routinely removed from service for recalibration.

The Operator should be able to demonstrate the integrity of all relevant vent and drain systems. The use of ‘double-block and bleed’ valves is strongly recommended.

5.5.3 Temperature and Pressure Measurement

Temperature and pressure measurement points should be located so as to ensure that the parameters measured are representative of conditions at the meter. To this end, they should be situated as close to the meter as possible without compromising meter performance.

Thermowells should be provided adjacent to the temperature measurement points so that the temperature measurement may be verified by comparison against certified test thermometers.

5.5.4 Temperature and Pressure Compensation

Where a flow meter is operated at a temperature and pressure different from that at which it was calibrated, an offset in meter performance may be expected.

Where temperature and/or pressure compensation routines are applied, these must be agreed in advance with DECC. The relevant calculations must be traceable and auditable.

5.6 METER PROVERS

Pipe provers may have significant footprints and they may be relatively expensive to install and maintain. However, the use of a prover permits the *in-situ* calibration of the primary flow element and as such represents the optimal solution from the point of view of minimising measurement uncertainty.

5.6.1 Prover Design

Prover loops should preferably be of the bi-directional type to eliminate possible directional bias. The prover loop's swept volume should have a suitable internal lining. The flanged joints within the calibrated volume should have metal-to-metal contact and there should be continuity within the bore.

The prover loop should be provided with connections to facilitate recalibration with suitable equipment such as a dedicated water-draw tank or a portable prover and transfer meter.

Unless it is proposed to use pulse interpolation techniques, at least 20,000 meter pulses should be generated over the swept volume per proving run. (This is equivalent to 10,000 pulses between detectors on bi-directional provers.)

The resolution of the detector/displacer system should be compatible with the above requirement.

5.6.2 Compact Prover Water Draw (Pre & Post)

Prior to and following a prover calibration, a water draw should be performed to establish the compact prover's base volume.

The base volume may be determined gravimetrically or volumetrically. As a rule, the uncertainty in a gravimetric calibration will be lower since it is insensitive to the thermal expansion properties of the water.

The water draw must be performed using de-aerated water.

5.6.3 Prover Calibration Uncertainty

Successive versions of regulatory and industry guidelines have set the year-to-year repeatability requirement at ±0.02% (irrespective of the calibration medium). The origin of this figure is unclear; at some point in the past it was evidently felt to be realistic and achievable. Indeed, the vast majority of prover calibrations have successfully met this repeatability target - sometimes with a minimum of difficulty, sometimes only after prolonged attempts. Such an approach can now be shown to lead to the rejection of valid results, and to thereby potentially introduce bias in the determination of prover base volumes.

Recent work has indicated that the figure of 0.02% is unrealistically low, at least where prover base volumes are determined using product as the calibration medium. For calibration using crude oil, the analysis suggests that at 95% confidence, current techniques are only capable of determining prover base volumes to within ±0.04% of the 'true' figure. Where water is used, the corresponding uncertainty is ±0.02%. (The second figure is lower principally because of the lower uncertainty in the compressibility of water compared to crude oil.)

5.6.4 Prover Calibration Acceptance Criteria

Provided the result of the prover calibration agrees with the previous calibration to within the calibration uncertainties presented above (i.e. ±0.04% for a calibration using product or diesel as the calibration medium, ±0.02% for a calibration using water), it may be accepted automatically.

Where the result differs from the previous calibration by more than the relevant tolerance, it must be verified by a repeat calibration at a different flow rate – preferably at least 25% different

DECC should be consulted if there is any doubt about the acceptability of the result of a prover calibration.

5.6.5 Prover Calibration Medium

The figures given in 5.6.3 above indicate that a lower calibration uncertainty results where the prover is calibrated on water rather than product. The use of water may also be desirable on other grounds; for example, it may be easier to ensure process and/or temperature stability. The water source should be verified as being suitable for the purpose of prover calibration (i.e. it should not contain quantities of entrained air sufficient to introduce measurement error).

However, there is one potentially serious issue that arises from the use of water: any wax deposited on the prover walls while the prover is drained may remain there during a water calibration, only to be subsequently dissolved by product when the prover returns to service. This problem is likely to be particularly acute when the temperature of the water used to calibrate the prover is low compared to the normal operating temperature of the prover. DECC has seen evidence of negative step changes in prover base volume consistent with this; these changes have subsequently been reversed when the calibration has reverted to product. DECC should therefore be consulted whenever it is proposed to use water as the calibration medium.

5.6.6 Method of Determining Base Volumes

Prover calibrations have been historically required to be based on the average of 5 consecutive measurements of base volume, with a maximum range of ±0.01% of their mean. While this is practice is clearly aimed at ensuring that conditions are reasonably stable during the determination of prover base volume, its statistical basis is not clear. With the increasing maturity and the associated process instability of many North Sea assets, this repeatability criterion is becoming increasingly difficult to satisfy.

Alternative methods of determining prover base volume may also be acceptable. For example, the base volume may be calculated using a recognised statistical analysis method (e.g. based on API MPMS Chapter 13 – Statistical Aspects of Measuring and Sampling, Section 2 - Methods of Evaluating Meter Proving Data). The actual number of runs required will be dependent on the range of results and target uncertainty.

Operators wishing to adopt such an approach are invited to put their proposals to DECC.

The method used should be indicated in the prover calibration report.

5.6.7 Prover Calibration Frequency

Calibration frequencies should whenever possible be based on a cost/benefit approach, consistent with the principles outlined in Chapter 4 of these Guidelines. The cost of recalibration should be weighed against the potential financial exposure resulting from mismeasurement that could be realistically expected to occur.

These calculations should be based on:

- an estimate of the largest shift that could be reasonably expected to occur, based on the results of the previous 5 calibrations;
- the financial consequences of such a shift, based on the estimate above and a nominal crude oil price;
- an estimate of the typical prover calibration cost

Operators' proposed frequencies should be submitted to DECC, along with the justification for the proposal. Where no such justification is submitted, the prover calibration frequency shall default to annual.

In exceptional circumstances, e.g. where the throughput of a metering station is relatively high, or where there has been a poor degree of historic stability in prover base volumes, DECC may require an Operator to calibrate the prover at a frequency higher than once per year.

5.6.8 Prover Calibration – Expectations on Operators

The calibration of the prover will normally be carried out by an independent third party, referred to as the 'Calibrating Authority'.

Operators must recognise the fact that the calibration of the pipe prover is the single most important calibration activity on an oil export metering system, and must make every effort to ensure that the activity proceeds as smoothly as possible.

To this end, as a minimum DECC expects Operators to co-operate fully with the Calibrating Authority, and to take a number of steps before, during and after the calibration. These are set out in Appendix 5.1 of these Guidelines.

5.7 TURBINE METERS

5.7.1 Meter Installation

Turbine meters should be installed as per the manufacturers' recommendations.

5.7.2 Meter Linearity

While it may be possible to detect changes in turbine meter performance by means of *in-situ* proving, the effect of such changes will be minimised by the selection of meters that are relatively insensitive to changes in flow rate and viscosity.

In certain applications the process conditions may be particularly unstable. For example, process flow rates may vary considerably, especially as fields mature and increasing water cuts begin to place a strain on separator level control. Where fluids from more than one field are measured, the fluid viscosity may be expected to vary as the proportion of each field in the commingled 'blend' varies.

DECC expects the linearity of turbine meters to be within ±0.15% across their range of operational flow rates.

5.7.3 Reverification Strategy

The strategy to be followed is fundamental to the design of the metering system and must be considered at the design stage.

There are essentially 3 alternatives for the periodic reverification of turbine meters:

- calibration in-situ using a prover.
- comparison with master meter.
- removal and recalibration at traceable test facility.

5.7.4 Calibration of Turbine Meter by Prover

This has historically been by far the most commonly-adopted approach and represents the optimal solution in terms of minimising measurement uncertainty. It provides an unrivalled facility to characterise the primary flow element on product and *in situ*, with minimal intervention.

At any given time the k-factor used by the stream flow computer (normally that determined at the most recent meter prove) should be representative of that being generated by the turbine meter in its current operating conditions. That is to say, the in-use k-factor should be within a pre-determined value, δ, of the 'true' k-factor. The value of δ is defined by the Operator at system design stage. Its value is generally constrained by the need to maintain the overall dry mass uncertainty within ±0.25%, and is typically 0.1%.

5.7.5 Performance Curves

For each meter that is to be operated over a wide flow range covering flow rates below 50% of maximum, a characteristic 'Performance Curve' of meter k-factor versus flow rate should be generated. This allows the Operator to determine the variation in flow rate that would cause a shift in k-factor of greater than the value of δ referred to in 5.7.4 above – essentially this sets one of the 're-prove alarm limits'.

The Performance Curves should cover a range from 10% from 100% of maximum flow rate. It is recommended that 5 proves are carried out at each nominal flow rate over the range of anticipated operation.

5.7.6 Meter Re-Proving

The sensitivity of the k-factor to variations in process conditions (temperature, pressure, density) should also be determined and used to set the relevant 're-prove' alarm limits, i.e. the amount of variation in each of these parameters sufficient to cause a change in k-factor of the value δ defined in 5.7.4 above. (For δ=0.1% these figures may be expected to lie in the region of 5℃, 10 bar pressure and 2% density.)

The routine proving strategy should be discussed with DECC and set out in the Operator's PON6 for the measurement system.

As a general rule, the proving frequency for continuous export systems should be set so that no more than 5% of routine proves show a shift in excess of δ, as defined in 5.7.4 above. (This is consistent with the figure of δ being quoted at 95% confidence level in the Operator's uncertainty budget for the measurement station.)

Pipeline entry requirements are likely to set the maximum interval between successive proves at 7 days or less. DECC should be informed whenever the prover is unserviceable for a period in excess of 15 days.

The proving strategy for tanker loading or batch export systems shall be agreed with DECC on a case-by-case basis.

Proving records must be made available to DECC for review.

5.7.7 k-factor Determination – Standard Method

The 'standard' method for determining the k-factor is as follows:

- k-factors should be determined on the average of at least 5 consecutive proof runs
- The meter k-factor calculated for each of the consecutive proof runs must lie within ±0.05% of the mean value of these runs.

5.7.8 k-factor Determination – Statistical Method

DECC will consider alternative statistical methods where appropriate, for example when unstable process conditions prevent the repeatability criterion in 5.7.7 from being met.

The goal of the proving process is to provide the flow computer with a k-factor which is representative of that produced by the meter under normal operating conditions. Operators must resist the temptation to impose a non-standard set of operating conditions on the meter in order to facilitate the downloading of an acceptably-repeatable k-factor. In such situations it is preferable to adopt a statistical method.

The k-factor may be calculated using a recognised statistical analysis method (e.g. based on API MPMS Chapter 13 – Statistical Aspects of Measuring and Sampling, Section 2 - Methods of Evaluating Meter Proving Data). The actual number of runs required will be dependent on the range of results and target uncertainty. The use of such a statistical method should be agreed in advance with DECC.

The method used should be indicated in the prover report.

5.8 ULTRASONIC METERS

5.8.1 Initial Calibration

The meter must be flow calibrated at a traceable facility prior to its installation in service.

The meter should be calibrated over all of the anticipated flow range, with particular attention paid to the expected operating flow rate. The meter should normally be calibrated at least six 'nominal' flow rates evenly-spaced within the range, with interpolation of the calibration offset for flow rates not directly covered. To maintain traceability, the calibration data and interpolation calculations should be stored within the flow computer rather than the meter electronics.

The necessary steps must be taken to ensure that the flow profile at the meter during the calibration is representative of that which the meter will experience during service.

The choice of calibration fluid should be discussed with DECC. The simplest approach is to calibrate the meter on a fluid similar to that which the meter will measure in service. Where this is not possible, DECC will normally require the Operator to determine the meter's Reynolds' number response.

5.8.2 Meter Installation

The straight pipe sections located immediately upstream and downstream of the meters should be fabricated and installed to ensure minimum impact on the meter uncertainty.

Meter manufacturers should be consulted regarding the minimum number of straight lengths required.

5.8.3 Flow Conditioners

The use of flow conditioners negates one of the principal operational advantages offered by ultrasonic meters, i.e. the absence of any restrictions in the flow line. However, their use may be necessary in order to address concerns over possible installation effects (e.g. where there may be insufficient space for the required number of straight lengths upstream of the meter).

If flow conditioners are proposed as part of the system design then the type and location of these devices should be discussed with the meter manufacturer prior to installation.

5.8.4 Reverification Strategy

Essentially, there are three possible approaches to the periodic reverification of liquid ultrasonic meters;

- periodic removal and recalibration
- in-situ meter proving
- master meter

Where the periodic removal and recalibration of the meter is proposed, the interval between successive calibrations should be agreed with DECC. Operators are encouraged to adopt a 'risk-based' approach, as described in Chapter 4 of these Guidelines. However, in general one may state that the use of diagnostics from liquid ultrasonic flow meters as a means to extend the interval between successive recalibrations has been considerably less explored than in the analogous situation with gas ultrasonic meters.

In-situ meter proving, against either a pipe prover or (more commonly) a compact prover is now a reasonably well-established technique. Ultrasonic flow meters lack the inherent inertia of turbine meters, and are much more responsive to transient fluctuations in flow. As a result, the standard method for k-factor determination derived from experience with turbine meters (described in Section 5.7.7) is not suitable for use with ultrasonic meters. However, statistical methods may be used to establish a representative k-factor – see Section 5.7.8 for the approach to be followed in such cases.

A master meter may be used to periodically verify meter performance. The master meter will generally have a measurement uncertainty similar to that of the in-service meter. Where it is proposed to use another ultrasonic meter, the Operator must be able to demonstrate that sufficient steps have been taken to mitigate against the possibility of common-mode error. (For example, the master meter may be placed in a by-pass loop.)

Typically, the volumes measured by each meter over a given interval are calculated, using the appropriate volume correction factors to take account of the different conditions of temperature and pressure at each meter.

The proposed comparison method should be discussed with DECC at the design stage.

The master meter should be calibrated at a traceable facility prior to its installation in service, following similar principles to those applied to the use of such a meter as an 'in-service' device. To guard against the possibility of meter drift, it will normally be necessary to remove and recalibrate the master meter at intervals to be agreed with DECC.

5.9 CORIOLIS METERS

5.9.1 Initial Calibration

The meter must be flow calibrated at a traceable installation prior to its installation.

The meter should be calibrated over all of the anticipated flow range, with particular attention paid to the expected operating flow rate.

Calibration on water or other fluids is acceptable. Calibration against a mass flow standard will result in a lower calibration uncertainty.

5.9.2 Meter Installation

Coriolis meter performance is relatively unaffected by the flow profile at the meter. Therefore the configuration of the upstream and downstream pipework is of less importance than with other types of flow meter. Nonetheless, it is good practice to install the meter so that its flow profile is disturbed as little as possible.

The pressure drop across Coriolis meters is relatively high. To minimise the potential for 'flashing' of lighter hydrocarbons (with consequent degradation of meter performance), careful consideration must be given to the process design to ensure that the fluid stays above its vapour pressure as it passes through the meter. Any flow control valves in series with the meter should be placed downstream of it.

The meter should be securely clamped (e.g. through spool pieces) to ensure that meter performance is not adversely affected by plant vibration.

Where the operating temperature differs significantly from ambient, meters should be lagged in order to prevent the introduction of additional measurement error.

Meter manufacturers should be consulted regarding specific installation and operational considerations.

5.9.3 Meter Set-up

An initial zero check should be performed as per manufacturers' recommendations. During the zero check the process line should be full (but not flowing) and the conditions of pressure and temperature should be as close as possible to the normal process operating conditions.

5.9.4 Reverification Strategy

The strategy to be followed is fundamental to the design of the metering system and must be considered at the design stage.

Essentially, there are three possible approaches to the periodic reverification of liquid Coriolis meters.

- periodic removal and recalibration
- in-situ meter proving
- master meter

Where the periodic removal and recalibration of the meter is proposed, the interval between successive calibrations should be agreed with DECC. Operators are encouraged to adopt a 'risk-based' approach, as described in Chapter 4 of these Guidelines. The use of diagnostic techniques to detect shifts in Coriolis meter performance is becoming increasingly well-understood, and DECC may consider the use of such techniques to form the basis of a 'condition-based maintenance' approach.

The calibration of a Coriolis meter against a prover (normally a compact prover, which may be *in-situ* or portable) is possible. However, the uncertainty in such a comparison will be higher than for direct volume calibrations, since the density at the meter must also be determined. The approach to be taken here should be discussed with DECC, but for the lowest-uncertainty applications it will normally be necessary to use an on-line densitometer rather than rely on the density indicated by the Coriolis meter itself.

The use of a master meter to periodically verify Coriolis meter performance is now well-established. The proposed method should be discussed with DECC at the design stage.

The master meter should be calibrated at a traceable facility prior to its installation in service, following similar principles to those applied to the use of such a meter as an 'in-service' device. To guard against the possibility of meter drift, it will normally be necessary to remove and recalibrate the master meter at intervals to be agreed with DECC.

Some Coriolis meters may require linearisation, particularly when operated at flow rates towards the lower end of their design range. Such linearisation should ideally be performed by the flow computer.

5.10 DENSITY MEASUREMENT

5.10.1 Installation

Where densitometers are used two should normally be installed in series, with a discrepancy alarm feature (typically set at 1.0 kg/m3) in the associated flow computer. An alarm 'time-out' feature is useful to reduce the number of spurious alarms.

Where a single densitometer is used the flow computer should feature high and low density alarms.

Densitometers should be installed according to the manufacturers' specification and in general should be located as close to the volume flow meter as possible. They should be provided with measurement points so that conditions of temperature and pressure at the densitometer may be established.

Provision should be made for solvent flushing on systems where wax deposition may be a problem.

5.10.2 Traceable Densitometer Calibration

Once installed, densitometers should be recalibrated after a 12 month period has elapsed. Where two densitometers are used, the recalibrations should be 'staggered' so that at least one densitometer has been calibrated within the most recent six-month period. The most recently-calibrated device should be used as the 'duty' densitometer.

5.10.3 Densitometer JIP

During 2004/05 a Joint Industry Project (JIP) was set up to investigate evident shortcomings in the procedure by which densitometers were being been routinely calibrated. The JIP completed its work during 2009 and a report was issued.

Its main recommendations were as follows:

- Densitometers should be calibrated at their anticipated operating conditions, i.e. simultaneously at temperature and pressure, using one or more transfer fluids, the density of which has been determined across the required temperature and pressure range with an uncertainty not exceeding 0.01%, directly traceable to national standards.

- Interpolation routines or ρ, P, T models used to calculate transfer standard fluid density at calibration conditions must produce a calculated fluid density with a combined uncertainty (arising from the experimental data for the transfer standard fluid and the fitting routine) not exceeding 0.015%.

- The calibration facility should be capable of maintaining the temperature of the transfer standard fluid in the densitometer to ±0.02ºC and measuring it to an uncertainty not exceeding 0.05ºC.

- The calibration facility must be capable of maintaining the pressure of the transfer standard fluid in the densitometer to ±0.05 bar and measuring it with an uncertainty not exceeding 0.10 bar.

- The current form of the equation used to calculate density from densitometer period may still be used providing optimised values of the coefficients K18, K19, K20A, K20B, K21A and K21B have been determined in a calibration laboratory that meets the requirements specified above.

The JIP characterised four fluids against a traceable standard densitometer, the uncertainty of which was within 0.010%. For each fluid an equation was derived, providing a calculated fluid density with an uncertainty not greater than 0.015% across a combined range of 20 to 100ºC and 0 to 300 bar.

These four fluids, which are readily available commercially at the required purities, form the transfer standard which may be used to provide traceable densitometer calibration.

5.10.4 Calibration Procedure

DECC intends that the recommendations of the JIP described in 5.10.3 should be followed unless it can be shown that any associated benefits are outweighed by increased calibration costs. However, this must be married with practical considerations regarding the availability of commercial calibration facilities that are able to meet the relevant uncertainty and stability requirements.

It is also necessary to consider the form of equations used to implement densitometer response in flow computers. To implement a full multi-fluid calibration on a single densitometer over the full temperature and pressure range requires the use of additional calibration constants that are not presently (as of March 2012) supported by existing flow computers. A requirement from DECC to implement the required changes across all North Sea assets would place an unrealistic burden on Licensees and flow computer manufacturers.

Recent work indicates that a 'limited' calibration is possible using 3 fluids, which traceably characterises densitometer performance over a defined range of temperatures and pressures, and that this calibration can be implemented using the existing form of density equation, i.e. without the need for flow computer modifications. Where it can be demonstrated that a densitometer shall not be operated outwith a limited envelope of process conditions (typically a range of 10ºC and 10 bar), such an approach would be acceptable to DECC.

Where the range of process conditions is wider than that which can be accommodated by a 'limited' calibration, a full calibration may be required. This will involve flow computer modifications to permit the new densitometer constants to be implemented. In such cases, discussions with DECC should take place so that a timeframe for the implementation of the necessary changes may be agreed.

DECC shall contact the Operators of those systems that are considered to be at significant risk of mismeasurement by virtue of their specific operating conditions (e.g. high operating pressure and/or temperature, high throughput), so that the implementation of the calibration procedures described in 5.10.3 & 5.10.4 may be discussed.

5.11 SAMPLING AND ANALYSIS

5.11.1 Sampling Systems

Measurement stations should normally feature automatic flow-proportional sampling systems. These sampling systems provide weekly and daily samples which are subsequently analysed and form the basis of the allocation of value to each contributing element in an allocation system.

5.11.2 Design of Sampling System

Guidance in the design of an automatic sampling system is provided by ISO 3171, and the general principles of that standard should be followed.

Note: In recent years compliance with ISO 3171, in particular with the terms of Annex A (regarding water dispersion) has become a requirement from some pipeline operators. However, DECC has become aware of more than one ostensibly well-designed sampling system that has failed to comply with the requirements of Annex A, but which has subsequently been shown to nevertheless provide a sample with a satisfactory degree of water dispersion.

The overall aim of any sampling system is to deliver a representative sample for analysis; if it can be shown to do so by other means then DECC is content for it to be used, whether or not it complies with ISO 3171.

Sample lines should be provided with flow indicators to help demonstrate that the conditions for isokinetic sampling are being met.

In shared transportation systems the weekly flow-proportional sample normally forms the basis of the crude oil valuation procedure.

Water content may be determined on the analysis of either weekly or daily samples. Where the weekly sample is used, the daily figures may be substituted in the event of a failure of the weekly sample.

Where an analysis is used for fiscal purposes, the relevant laboratory should be certified to ISO 17025.

5.11.3 Water-in-Oil Meters

DECC will consider the use of on-line water-in-oil meters in certain applications. However, it should be borne in mind that for allocation purposes it will normally be necessary to provide a representative compositional analysis, so that a flow-proportional sampling system will be necessary whether an on-line water-in-oil meter is used or not.

5.11.4 Sample Receiver

The sample receiver should be designed to facilitate the homogenisation of the sample in the laboratory so that a representative sub-sample may be drawn from it.

A number of different sample receivers are commercially available. Whichever model is used, the operator should be able to demonstrate that the 'homogenising' capability of the sample receiver has been independently verified (at least in crude oil applications – see the note on condensate in the section 'Homogenisation of Sample in the Laboratory').

Operators are reminded that it typically takes 10 days for a sample receiver to reach an onshore laboratory from an offshore installation. Approximately 12 sample receivers are required per installation. These should remain dedicated to each product (i.e. those used for NGLs should be kept separate from those used for crude oil).

5.11.5 Surveillance of Sample Container

Operators are expected to have in place a suitable system to ensure that the volume of sample collected is within acceptable limits. The volume in the sample receiver should be noted at roughly 12-hourly intervals, and the record should be available for inspection.

For most commercially-available sample receivers, the volume collected should be between 2 and 3 litres. Above this limit, the sample cannot be homogenised by the normal method - a modified technique is required, which has potential for the loss of light ends (and thus revenue). If the amount collected is significantly below 2 litres, there may be insufficient volume for a full sample analysis to be completed.

5.11.6 Homogenisation of Sample in the Laboratory

In fiscal applications the degree of mixing required for homogenisation must be established. To achieve this it may, for example, be necessary to inject known quantities of water into samples of dry crude, mixing for a given time, and then taking samples for analysis to establish whether the water has been adequately distributed throughout the oil. The time taken may be expected to vary significantly from crude to crude.

Details of the above procedure should be available for review by DECC in fiscal applications.

Note: Unfortunately, condensate does not mix well with water. For any condensate application, demonstrating that the sample has been adequately homogenised prior to a sub-sample being drawn is likely to be extremely problematic. In such cases it is almost always necessary in practice to resort to solvent wash followed by mathematical recombination in order to arrive at a water content value for a condensate sample.

5.11.7 Review of Sampler Performance

DECC expects Operators to monitor their performance in returning weekly samples for analysis. The relevant data must be made available for review by DECC.

5.12 OFFSHORE LOADING SYSTEMS – CRUDE OIL EXPORT MEASUREMENT

5.12.1 Introduction

Most commonly, oil is exported to market via pipeline. However, in some North Sea applications oil is offloaded to shuttle tankers, which then transport their cargoes to 'ports of discharge' in the UK or overseas.

The point of sale in such cases is generally a matter for commercial negotiation. It may either be;

a) at the point of offshore loading, or

b) at the port of discharge.

In the case of a), the fiscal measurement is made prior to transfer to the shuttle tanker. This is generally achieved using measurement systems that are designed to custody transfer standards.

In the case of b), the fiscal measurement generally takes place at the port of discharge, which may be beyond the jurisdiction of DECC. It is with this scenario that the present section of the Guidelines is concerned.

5.12.2 Units of Measurement

In either scenario described in 5.12.1, the unit of sale is normally volume (barrels). Where the export measurement is achieved by volume meters (turbine or ultrasonic), there is generally no need to install in-line densitometer measurement. Unless the mass exported needs to be determined for sub-allocation purposes, density determination via laboratory analysis of samples taken during export is normally sufficient.

5.12.3 Bill of Lading / Outturn

The quantity offloaded to the shuttle tanker is termed the 'Bill of Lading'. This cargo is then delivered to the port of discharge.

Unless agreed otherwise (see 5.12.4 below), the Method of Measurement by which the Bill of Lading shall be determined must be agreed with DECC as part of the PON6 process for the relevant field(s).

The 'Outturn' is the quantity measured at the port of discharge. Under the scenario with which this section of the Guidelines is concerned, revenue for both the Operator and the Government is determined on the basis of this measurement.

Where the condition at 5.12.4 does not hold, the Operator must be able to demonstrate that the Outturn is representative of the Bill of Lading. It is in the interests of both Government and Operator that this is so.

In such cases, DECC expects Operators to have in place a system for the routine comparison of these figures. The database should contain, as a minimum, details of the following for each cargo:

- The Bill of Lading (gross fluid quantity, water content, dry oil quantity, oil density)
- The identity of the Shuttle Tanker
- The location of the port of discharge
- The Outturn (gross fluid quantity, water content, dry oil quantity, oil density)

Particular attention must be paid to the difference between the dry oil quantities determined onshore and offshore.

Estimates of the Bill of Lading shall be considered to be invalid where these have been adjusted in any way without prior consent from DECC.

The database held by Operators must be available for review on request by DECC.

Where a port of discharge is in routine use, DECC may insist that the Operator carries out an independent assessment of the uncertainty of the measurement station used to determine the Outturn.

The Operator must maintain an auditable record of any adjustments made to the measurement system used to determine the Bill of Lading.

5.12.4 Jurisdiction

In certain cases, the Operator has been able to guarantee that the Outturn shall be determined at a measurement station over which DECC has jurisdiction. For example, shuttle tankers may deliver cargoes to dedicated tanks at UK terminals (e.g. Sullom Voe, Flotta, Nigg), with subsequent export through fiscal measurement stations.

In such cases, there is no need for the Bill of Lading to be scrutinised by DECC.

5.12.5 Recent Standards and Guidance Documents

NSFMW	Author(s)	Title	Relevant Content
Tønsberg 2009	Martin, P.	Realistic pipe prover volume uncertainty.	Uncertainty of prover calibrations. Effect of calibration medium.
Tønsberg 2011	Brown, G., Griffith, B. & Augenstein, D.	The influence of flow conditioning on the proving performance of liquid ultrasonic meters.	Statistical proving methods – generic (i.e. not specific to ultrasonic meters).
Tønsberg 2011	Seiler, D. & Syrnyk, P.	Field experience proving liquid ultrasonic meters using a small volume prover and master meter.	Statistical proving methods.
Tønsberg 2011	Fosse, S. et. al.	Are Coriolis mass meters suitable for fiscal liquid applications?	Laboratory calibration of Coriolis meters against turbine meter and small volume prover. Assessment of installation effects under laboratory conditions.
Tønsberg 2011	Jiskoot, M.	Sampling, mixing and quality measurement. Comparing 35 years of field experience with the measurement standards.	Review of existing sampling standards. Limitations of CFD analysis.

UK National Measurement System Guidance Note – Installation and set-up of Coriolis mass flow meters (NEL, 2011) – available at http://www.tuvnel.com.

Traceable Calibration of Liquid Densitometers – JIP Final Report (NEL, 2009).

APPENDIX 5.1 – EXPECTATIONS ON OPERATORS DURING PROVER CALIBRATIONS

The calibration of the prover will normally be carried out by an independent third party, referred to as the 'Calibrating Authority'.

Operators must recognise the fact that the calibration of the pipe prover is the single most important calibration activity on an oil export metering system, and must make every effort to ensure that the activity proceeds as smoothly as possible.

To this end, as a minimum DECC expects Operators to co-operate fully with the Calibrating Authority, and to take the following steps before, during and after the calibration.

Prior to the Prover Calibration

The installation Management must ensure that all relevant site staff have been briefed in advance of their roles and responsibilities so that disruption to the calibration activities is minimised.

The Operator must appoint a member of site personnel to liaise with the Calibrating Authority's calibration engineer.

A 'lay-down' area for the prover calibration rig must be prepared prior to its arrival.

All necessary Permits-to-Work and/or Isolations must be in place in order to enable the calibration to proceed as soon as possible after the Calibrating Authority's personnel arrive on site.

The Operator must ensure that:

- The prover 4-way valve is not leaking. (Particular attention should be paid to this. Recent Calibrating Authority experience suggests that 4-way valve integrity failure is one of the most common sources of delay.)
- All relevant isolation valves are leak free, and a means of testing or proving their integrity established.
- All relevant thermowells have been cleaned out and are ready to be filled with thermally conducting oil.

Unless an 'As Found' calibration is required, the site prover must be drained, with the prover sphere removed and ready for immediate inspection by the Calibrating Authority.

As a minimum, the following spares should be held:

- 4-way valve slips
- Prover door seals
- One complete set of prover detector switches; these should have been checked for correct operation and for correct insertion depth.
- Prover sphere valves.

The Operator should check that a spare prover sphere of the correct size, material, and condition is available, as well as all necessary sphere tools and a sphere pump. A readily-available supply of glycol should also be provided.

The Operator should contact the Calibration Authority to determine which specific site services are necessary, and then ensure that that these are provided. For example, the provision of the following may need to be considered:

- Power supplies (440 Vac, 240 Vac or 110 Vac) with suitable connections. (Particular attention should be paid to electrical safety matters, in view of the fact that the calibration rig will be connected to the electrical mains while it is filled with 'live' product.)

- Potable water for flushing the master prover at the end of the calibration.

The Operator must have available a suitable pump for hydro-testing or leak-testing the hook-up of the site prover to the calibration rig.

During the Prover Calibration

During prover calibration, the Operator should strive to maintain, as far as possible, steady flow through the metering station. The Operator must remain attentive to the requirements of the calibration, as determined by the Calibrating Authority's engineers.

The decision as to whether or not the calibration has been completed satisfactorily ultimately rests with DECC. The Calibrating Authority is obliged to follow DECC's criteria, as detailed in Section 5.6.4 of these Guidelines, for the acceptability or otherwise of the result of a prover calibration.

After the Prover Calibration

After the prover calibration has been completed, the Operator's personnel should endeavour to isolate and depressurise the prover pipework as quickly as possible without compromising safety.

Once the prover calibration has been completed, the Operator must make every effort to ensure that the master prover is removed from site as soon as possible, in order not to create any 'knock-on' delays at the site of the next prover calibration.

The new volumes should be implemented into the computer as soon as the official certificates are available.

6 SINGLE-PHASE GASEOUS HYDROCARBON MEASUREMENT

6.1 INTRODUCTION

This Chapter of the Guidelines deals with Custody-Transfer standard flow measurement of dry, processed gaseous hydrocarbons.

Wet gas flow measurement applications are considered separately, within the chapter on Multiphase Metering.

6.2 MODE OF MEASUREMENT

All measurements must be made on single-phase streams.

Hydrocarbon flow rate measurements may be in either volumetric or mass units. The choice of measurement should however be agreed with DECC.

Where volume is the agreed measurement unit, it should be referred to the standard reference conditions of 15°C temperature and 1.01325 bar absolute pressure (dry).

In shared transportation systems it is normal practice for value to be attributed to the contributing fields on either a gross energy or on a component basis. In either case, there should be provision for the determination of gas composition.

Gas density at the meter may be determined by:

a) Continuous direct measurement by an on-line densitometer;

b) Calculation, using a recognised equation of state together with measurements of gas composition, temperature and pressure.

The use of the two methods in parallel provides a valuable cross-check on the measurement station as a whole, and is DECC's preferred approach.

DECC may consider the use of calculated density only, subject to certain criteria being met. Further Guidance is provided below in section (6.6).

6.3 METERING STATION DESIGN – GENERAL CONSIDERATIONS

6.3.1 Avoidance of Liquid Carry-Over

Metering stations should be designed to minimise the probability of liquid carry-over into the metering section, and from any condensation or separation that would have a significant effect on measurement uncertainties.

6.3.2 Secondary Instrumentation

Secondary instrumentation is typically required for the recording of representative measurements of the following parameters:

- Line pressure.
- Differential pressure (where applicable).
- Line temperature.
- Flowing density.
- Density at base or standard reference conditions.

- Gas composition (where applicable).

Where possible, provision should be made for the on-site verification of these secondary measurements.

6.3.3 Meter Tube Inspections

It may be necessary from time to time to examine the condition of the meter tubes to ensure that corrosion, erosion or contamination has not occurred to an extent likely to affect the accuracy of the meter. If flow conditioners are used, these should also be examined for contamination and any obvious surface damage.

It is recommended that boroscopes are used for inspection purposes, and video recording facility should be utilised where possible in order to provide a traceable record of the inspection.

Test thermowells should be provided adjacent to the temperature measurement thermowells so that the temperature measurement may be verified by comparison against certified test thermometers.

6.4 DIRECT DENSITY MEASUREMENT

It is important that the gas entering the densitometer is representative of the gas in the line, in respect of composition, temperature, and pressure. This becomes critically important if, as is generally the case, the pressure and temperature are not measured directly at the densitometer.

In DECC's experience, failure to take account of this factor in the design of densitometer installations is one of the principal causes of significant mismeasurement in North Sea applications.

Therefore, unless the temperature is measured directly at the densitometer, installations must be designed to so that:

- The effect of ambient conditions (normally a cooling one) on the temperature of the gas sample is minimised. This may mean keeping the densitometer inlet line in close thermal contact with the meter tube; ideally it should be placed under any lagging. In extreme cases it may be necessary to heat-trace the line; in this case care must be taken not to over-heat the sample.

- There is no pressure drop between the densitometer and the point in the system where pressure is normally measured. All isolation valves between the densitometer and the pressure measurement point must be of the full-bore type. It should be possible to demonstrate that there is flow through the densitometer loop.

Densitometer installations should be designed so that, as well as meeting the above criteria, they also offer the facility for easy and efficient removal of densitometers and, preferably, the facility to readily view their Serial Numbers for auditing purposes.

Gas densitometers used in offshore applications should be introduced into service no more than 12 months after the date of their onshore calibration. Their period in service should then not normally exceed 12 months.

6.5 ON-LINE GAS CHROMATOGRAPHY

Determination of gas composition at the measurement station shall normally be achieved via the use of on-line gas chromatography.

Manual sampling points should also be provided, so that in the event of the failure of one or more critical components of the gas chromatograph system, representative samples may be taken and analysed off-line.

A recent NSFMW paper [Fosse et. al., 2010] provides a good working summary of developments in on-line gas chromatography since this technology first began to be used in North Sea fiscal applications.

The use of gas chromatography in fiscal measurement is critically important for gas sales and allocation purposes for the following reasons:

- The value of natural gas at the point of sale is a function of its calorific value. This is normally determined by the use of an International Standard [ISO 6976: 1995], which requires knowledge of the gas composition.

- Gas pipeline allocation is normally performed on a component mass basis; in such circumstances it becomes necessary to be able to determine the mass of each component contributed by each element in the allocation system.

- On-line measurement of gas composition permits the determination of physical properties of the gas (e.g. density, speed of sound) which may then be compared with the values of these same parameters determined by other means (densitometer, gas ultrasonic meter).

6.5.1 Sample Point

Paragraph 8.1.3 of ISO 10715 provides guidance on the location of the sampling probe:

- The sample point should be situated in an area where the gas is well mixed and representative of the fluid flow, but where dust and aerosols are not encountered.

- The sample probe should be located at the top of the meter tube and should be inserted so that gas is withdrawn from the central third of the pipe.

- Isolation valves on the sample probe should be full-bore.

Each system should also feature a manual sampling point to permit spot samples to be taken when required.

6.5.2 Sample Phase Behaviour

The phase behaviour of the gas to be analysed should be established at the design stage. Where the gas composition is expected to vary (for example, in systems used to analyse the commingled gas from more than one reservoir) the extent of the single-phase ‘envelope’ for the expected range of compositions should be established.

The relevant calculations should be available for review by DECC.

6.5.3 Sample Line

Section 8.2 of ISO 10715 provides guidance in the design of the sample line. Some key points to note:

- The sample-handling system must be designed so that the sample remains in its gaseous phase throughout its transport from the sample point to the on-line gas chromatograph, across the full range of compositions that may be encountered in service. It may be necessary to install trace heating to insure against the possibility of liquid drop-out due to ambient cooling of the sample gas.

- The length of the line from the sample point to the gas chromatograph should be kept to a minimum. It should be inclined so that any liquids that do drop out of the gas are carried away from the chromatograph.

- The sample line diameter should not be less than 3 mm.

6.5.4 Sample Response Time

In general, sample response times should generally be within 2 minutes (or less than the GC cycle time). Where this is not possible, DECC may require the impact of the sample delay to be evaluated.

6.5.5 Pressure Let Down System

In most fiscal applications, the operating gas pressure is significantly higher than the operating pressure of the gas chromatograph, and it is therefore necessary to reduce the pressure of the sampled gas in at least one intermediate stage before it is analysed. The possibility of liquid drop-out of the heavier components of the gas as a result of Joule-Thomson cooling must be considered at the design stage and all reasonable steps (for example, the use of heated regulators or valves) must be taken to avoid its occurrence.

Section 8.5 of ISO 10715 provides some useful guidance on the design of pressure let-down systems. These should feature:

- pressure and temperature indicators so that the correct conditioning of the sample may be demonstrated
- a flow indicator

6.5.6 Gas Chromatograph

The optimal choice of chromatograph model is a function of the characteristics of the gas to be analysed and should be discussed in advance with DECC.

Design engineers should note that the use of a chromatograph featuring component analysis to C9+ (or higher) may be required by the pipeline authorities.

6.5.7 Evaluation of Linearity and Repeatability– ISO 10723

A procedure for determining the linearity and repeatability of gas chromatograph response on 7 different test gases is set out in an International Standard [ISO 10723: 1995]. This standard is currently in the process of being updated, under the aegis of ISO TC/193; an alternative method based on the use of 3 test gases (following the procedure set out in NORSOK I-104) is likely to be adopted.

DECC may require operators of relevant systems to quantify at regular intervals the linearity and repeatability of fiscal gas chromatographs. An appropriate frequency of testing may be determined following the procedures outlined in section 4.1.8.

6.5.8 Calibration Gas

The composition of the calibration gas should be broadly similar to that of the process gas typically analysed by the chromatograph.

The composition of the calibration gas should be determined by an accredited laboratory (UKAS or overseas equivalent) and a certificate detailing the gas composition should be available for inspection. This calibration certificate should indicate:

- the uncertainty to which each component concentration has been determined (the uncertainty limits are a function of the relevant mol%; typical figures are indicated in NORSOK I-104, para. 9.1.4.1)
- the minimum storage temperature of the gas
- the serial number of the calibration gas bottle to which it corresponds

Once on site, calibration gas bottles should be stored vertically in an enclosed space heated to at least the indicated minimum storage temperature of the calibration gas, and preferably higher. In general it should not be assumed that the gas bottle will have been maintained above its minimum storage temperature during transportation to its in-service location. To take account of the possibility of retrograde condensation of the heavier components, the bottle should be stored at a temperature above the minimum storage temperature for at least 24 hours prior to use to allow the calibration gas to return to its original condition.

The use of the calibration gas at a temperature below its dew point invalidates its certification.

The relevant handling procedures should be available to DECC for review.

6.6 Use of Calculated Density

The use of an equation of state (as in 6.2 b) above) as the sole method of determining the density of the measured gas requires prior agreement from DECC.

Where it is proposed to move from ‘measured’ to ‘calculated’ density, a new system uncertainty calculation shall be required.

Where density is determined by an equation of state the accuracy of the ancillary instrumentation has additional significance. Typical sensitivities to changes in process variables are as follows:

Variable	Change	% Change in Density
pressure	1%	1.0
temperature	1°C	0.7
molecular weight	1%	1.6

Note that the uncertainty in the calculated density (including chromatograph, temperature & pressure measurements, AGA8, etc.) is generally two to three times higher than that which is possible with a good densitometer installation. The higher calculated density uncertainty can pose difficulties for systems based on the use of ultrasonic meter required to stay within an overall uncertainty of 1.0%. The impact on orifice plate systems is much less, (in view of the square-root relationship between mass flow rate and density), with most systems just requiring a modification to the low flow alarm limit (to stay within 1.0% uncertainty).

The lack of a ‘cross-check’ (in the form of directly-measured density) necessitates an increased degree of scrutiny on critical elements of the sampling and analysis system, as well as the measurements of pressure and (especially) temperature.

In general, DECC shall require that the following conditions are met:

- The gas chromatograph should be subject to a ‘health check’, the frequency of which may be determined on a ‘risk-based’ analysis. DECC may insist on ISO 10723 certification (6.5.9 refers).

- Where the composition, pressure or temperature lies outwith the expanded limits of AGA8, DECC may require that a new equation of state is derived. New or upgraded systems will be expected to take account of ISO 12213 (Table 1) for the treatment of other components outwith the normal AGA 8 component list. Where a new equation of state cannot be implemented, the additional uncertainty resulting from the use of AGA8 should be quantified.

DECC would accept the use of the GERG 2008 equation of state, which covers a wider range of components and conditions than AGA8. However, at present it is not believed that this equation of state has been implemented in commercially-available flow computer systems.

- A contingency plan must be in place to deal with contamination in the sample lines, pressure let down system and gas chromatograph(s).

- A system must be in place to prevent the downloading of spurious gas composition data (for example, ‘high’ and ‘low’ alarm limits should be defined for each analysed component and for the un-normalised component total).

Where a cross-check is available, an alarm should be raised when the discrepancy between measured density and calculated density exceeds an agreed limit.

6.7 ORIFICE PLATE SYSTEMS

6.7.1 Introduction

For new measurement systems the design, installation and operation shall normally be expected to comply with the principles of ISO 5167.

6.7.2 Implementation of ISO 5167

At periodic intervals, critical equations in ISO 5167 may be updated. (Most notably, the equations for the orifice plate discharge coefficient and the downstream/upstream temperature correction have both been updated within the past 15 years.)

In such cases, it is necessary to consider how the changes should be implemented at a pipeline level.

In shared transportation systems, value is generally allocated to the contributing elements on the basis of quantities measured at the terminal sales gas metering stations. Where these metering systems make use of orifice plates, DECC expects Operators to implement the latest version of ISO 5167 in full.

At the entry-points to shared transportation systems featuring orifice plate metering stations, DECC's primary concern is to avoid the introduction of unnecessary measurement bias. To this end, the need to use a common version of ISO 5167 at entry-points takes precedence over the normal desire to use of the latest version of the standard.

Proposals to implement new or modified requirements contained within the current revision of ISO 5167, either partially or in full, should be co-ordinated by the relevant pipeline Operator and discussed with DECC prior to implementation.

6.7.3 Design Considerations

The orifice plate metering assembly should, be designed and constructed such that the minimum uncertainties specified in ISO 5167 are achieved and adherence is maintained to the limiting factors detailed in the standard together with the additional specifications detailed below:

a) The total deformation including plastic and elastic deformation of the orifice plate at maximum differential pressure should be less than 1%.

b) The uncertainty in flow measurement caused by the total deformation of the orifice plate should be less than 0.1%.

c) The location of the differential pressure tappings with respect to the orifice plate should remain within the tolerances given in ISO 5167 over the full operating ranges of the differential pressure transmitters. Where plate carriers utilise resilient seals, care should be taken to ensure that the load on the plate caused by the maximum differential pressure does not move the plate out of the pressure tapping tolerance.

d) If the maximum differential pressure across the orifice exceeds 500 mbar, it should be demonstrated that the conditions of b), c) and d) are met.

The latest versions of ISO 5167 provides increased scope for the use of ß-ratios higher than 0.6. Higher ß-ratios may be used, provided the overall uncertainty remains below the system design uncertainty.

6.7.4 Meter Runs

Sufficient meter runs should be provided to ensure that, at the maximum design production rate of the field, at least one stand-by meter is available.

Meter runs should not be situated at low points in the system where there is potential for the accumulation of process liquids.

The Operator will normally be expected to provide an adequate level of isolation valving so that individual orifice plates may be removed from service without the need to shut down the entire metering or process system. Such requirements may, under certain circumstances, be waived if suitable alternative fallback options can be formulated and agreed in advance with DECC.

6.7.5 Flow Pulsations

The orifice metering station should be located such that pulsations in the flowing gas are avoided. Where these are unavoidable, the uncertainty in flow due to any such effects should be kept below 0.1%.

Useful guidance in such situations may be found in ISO Technical Report 3313.

6.7.6 Upstream and Downstream Pipework

The metering station should be positioned within a process facility such that the effects of fittings and pipework, both upstream and downstream of the orifice meters, do not impact on the minimum straight length requirements given in the relevant version of ISO 5167.

If flow conditioners are proposed as part of the design, the type and location of these devices should be discussed with DECC. In addition, provision should be made to periodically inspect these devices, ideally in situ (e.g. via the use of inspection ports located on the flanges supporting the flow conditioner).

6.7.7 Differential Pressure Diagnostics

The use of diagnostic systems based on the use of an additional measurement of the fully-recovered pressure is gradually becoming well established. Experience has shown that this technique enables the Operator to detect significant deviations from normal operating conditions as they arise. It may therefore form the basis of a condition-based maintenance strategy, as described in Chapter 4 of these Guidelines; DECC has already agreed to the adoption of such a strategy at a major UK terminal.

Operators of new developments are strongly encouraged to consider the adoption of such a strategy. The provision of an extra pressure tapping costs relatively little at the design and manufacturing stages, but may permit significant operational savings to be made during the life of the field.

Operators should note that, as with any condition-based maintenance strategy, provision must nevertheless be made for the isolation of the primary measurement element, since it may still be necessary to remove the orifice plate should the diagnostic system indicate that plate damage or contamination has occurred.

6.7.8 Pre-Commissioning

The Operator should prepare a schedule of pre-commissioning tests to demonstrate the compliance with the relevant metrological requirements of ISO 5167. In particular, the interior of the meter tubes and of the orifice bores should be examined to ensure they conform to the relevant provisions of the Standard.

6.7.9 Start-up Plates

If there is a risk that debris including dust, mill scale or other foreign matter may be present in the process upstream of the meters then consideration must be given to the use of ‘start-up’ orifice plates to avoid damage to the primary elements intended for long-term metering service.

6.7.10 Orifice Plate Inspection

Where a condition-based monitoring system is proposed, a time-based inspection program should be in place during the initial operational period.

Where it is not proposed to adopt a condition-based maintenance strategy (as described in Chapter 4 of these Guidelines, and referred to in 6.7.7 above), a time-based inspection regime must be planned and implemented.

Once it has been established that plate contamination is not likely, DECC may agree to the extension of the interval between successive inspections. A typical inspection sequence, assuming that the condition of the plates is satisfactory on each occasion, might be:

- 6 plate inspections at 1-month intervals
- 2 plate inspections at 3-month intervals.
- 2 plate inspections at 6-month intervals.

- Annual plate inspection.

On plate contamination or damage being encountered, the inspection frequency automatically reverts to the previous stage in the above sequence.

At onshore Terminals, DECC expects a full gauging examination to the provisions of ISO 5167 to be conducted in each case.

Elsewhere, when carrying out an examination of an orifice plate in the field, a more limited inspection is normally sufficient, though DECC may require individual metering stations to carry out full gauging examinations, for example where there is a very high throughput and/or a history of damage to orifice plates.

The main points of focus for an orifice plate field inspection are:

- Freedom from damage or rounding to the upstream edge within the orifice bore.
- Freedom from damage to the plate surfaces.
- Correct orientation within the carrier.
- Plate flatness.
- Plate cleanliness.

6.7.11 Edge Sharpness

ISO 5167 allows an edge roughness of up to 0.0004d (where d is the orifice diameter). However, ISO TR 15377 indicates that there is a more or less linear relationship between edge roughness and overestimation of discharge coefficient, Cd. On the tolerance limit (0.0004d), systematic overestimation of Cd by 0.1% can be expected.

The cost involved in re-machining the straight edge is likely to be insignificant compared with the costs involved in systematic mismeasurement of mass flow rate by up to -0.1%. Therefore if any damage to the upstream straight edge has occurred, it should always be re-machined and re-certified prior to re-use.

6.7.12 Meter Tube Inspection

As well as the general provision for meter tube inspection (referred to in 6.3.3), there are some additional considerations that are specific to orifice plate metering systems.

DECC may insist that a meter tube inspection takes place if periodic plate inspections show persistent contamination. Particular attention should be paid to the bore of the pipe section extending 2 pipe-diameters upstream of the orifice plate and also to the condition of the upstream and downstream pressure tappings at their respective points of breakthrough into the meter tube wall.

6.7.13 Differential Pressure Measurement

For onshore metering stations, differential pressure transmitters should be calibrated at high static pressure representative of the normal operating pressure for the instrument.

For offshore metering stations, high static calibrations should be performed at a suitable calibration facility and subsequently ‘footprinted’ at atmospheric pressure for use in periodic verifications offshore. The high-static pressure should be representative of that likely to be encountered offshore under normal operating conditions.

In the event of a differential pressure cell failing its calibration check, once liquid contamination, adverse pressure shocks etc. have been ruled out as possible reasons for the failure, adjustment offshore at zero static pressure may now be considered. The following conditions apply:

a) The static shift exhibited by the differential pressure cell at its onshore calibration is less than 0.05%.

b) The differential pressure transmitter has a proven history of static shift stability, i.e. at least two successive ‘footprints’ demonstrating compliance with the criteria.

c) The differential pressure transmitter damping factor is less than ≈1s (this gives a ≈5s response time to a step-change in differential pressure).

d) The uncertainty of the calibration standard is an order of magnitude lower than the operating tolerance of the transmitter under calibration.

e) The facilities provided for the calibration are conducive to good calibration practice – for example, a stable environment for the mounting and operation of the calibration standard will normally be required.

If an operator wishes to pursue this strategy, supporting data should be made available to DECC, who may then agree to the atmospheric calibration of differential pressure transmitters on an instrument-by-instrument basis.

Differential pressure transmitters should be introduced into service no more than 12 months after the date of their onshore calibration.

6.8 ULTRASONIC METER SYSTEMS

6.8.1 Introduction

For Custody Transfer standard applications, only transit time multi-path ultrasonic meters should be used.

6.8.2 Application of Standards

Where ultrasonic meters are proposed or used as part of a metering system, the design, installation and operation should comply primarily with general guidance given in ISO 12765, ISO 17089, BS 7965 and also in AGA 9 plus specific recommendations from the meter Manufacturer.

This applies particularly to the upstream and downstream pipe geometry.

6.8.3 Meter Redundancy

Multi-path ultrasonic meters clearly have an inherent redundancy capability. However, reliance on ‘back-up’ chords may not be sufficient, since an ultrasonic meter’s accuracy may be adversely affected in the event of chord failure, potentially increasing the overall uncertainty of the metering system outwith the agreed limits.

It is recommended that the degree of redundancy of an ultrasonic meter is clearly established at its initial flow calibration, i.e. chords should be intentionally ‘failed’ by disconnecting the relevant transducers so that the performance of the meter can then be evaluated in each case. This will help establish at what point it becomes necessary to remove the meter altogether in the event of the failure of one or more chords.

Sufficient meter runs should be provided so that a standby stream, fitted with a calibrated ultrasonic meter, is available at all times.

6.8.4 Isolation Valving

The Operator will normally be expected to provide an adequate level of isolation valving so that the ultrasonic meter may be removed from service without the need to shut down the entire metering or process system.

Removal of the meter may be necessitated by the failure of one or more of its components. The need for periodic removal of the meter for recalibration at an onshore laboratory must also be considered.

6.8.5 Installation Considerations

The metering station should not be installed where vibration or noise levels can interfere with the performance of the meter.

The straight pipe sections located immediately upstream and downstream of the meter should be selected, fabricated and installed to ensure minimum impact on the performance of the metering station or the specified measurement uncertainty.

The step between the ultrasonic meter and the upstream spool should meet the requirements referred to in 6.8.2, both 'in-service' and at the calibration facility.

If flow conditioners are proposed as part of the system design then the type and location of these devices should be discussed with the meter manufacturer prior to installation.

6.8.6 Flow Profile

The Licensee must ensure that the flow profile during meter calibrations matches, as far as possible, the predicted 'in-service' flow profile.

If the meter is to be installed with a flow conditioner, it must be calibrated with the same design of flow conditioner, in the same orientation and position within the meter run.

6.8.7 Flow Meter Calibration

The ultrasonic meter should be flow-calibrated prior to initial installation. This should take place at a recognised test facility, demonstrating either UKAS or International accreditation.

Where Operators do not wish to adopt a 'condition-based maintenance' strategy (as described below), the interval between successive meter recalibrations shall be agreed with DECC on a case-by-case basis. In common with the Department's approach in other areas, the economics of the particular field development will be taken into account when assessing the appropriate recalibration period. The approach to be taken in assessing the appropriate interval between calibrations is described in Chapter 4 of these Guidelines.

Meters should normally be calibrated in their 'as found' state so that any shift in meter performance from the previous calibration can be quantified.

Experience with ultrasonic meters over the past 7 years has shown that meters are likely to show the greatest shifts in the first 6 months of operation. It appears that the meter bore becomes 'conditioned' in-service during this period. Cleaning of the meter bore may therefore be counter-productive and should be avoided whenever possible.

At each meter calibration, the following information should be recorded:

- Serial Numbers and calibration history of the reference meters used at the test facility.
- Full details of the configuration of the pipework between the reference meter and the meter under calibration – type and position of bends, step changes in pipe diameter, etc.
- The position and type of any flow conditioners in the test line.

Operators should retain this information for each meter (preferably in a dedicated dossier). The relevant information should be available for inspection at all times.

At least 3 and preferably 5 runs should be performed at least 6 different flow rates, spaced more or less evenly between the minimum and maximum design flow rates for the meter.

Statistical interpretation of any data from ultrasonic meter calibrations should take into account the number of test runs at each flow rate. Following the principle of the '$1/\sqrt{N}$' law, the calibration uncertainty reduces with an increasing number of test runs (provided of course, that the test flow rate remains constant).

It is recognised that the practical possibility of increasing the number of test runs at each flow rate may be subject to financial and/or time constraints. Operators may therefore wish to consider whether increased attention should be paid to the expected operational flow rate, if necessary at the expense of other, less 'representative' flow rates. Such an approach has the potential to reduce the meter's operational uncertainty.

6.8.8 Transducer Replacement

Replacement of the ultrasonic meter transducers/detectors or electronics will normally necessitate recalibration of the meter, unless the effect of these actions has been quantitatively determined at the meter calibration and found to be insignificant.

Operators may wish to consider this requirement when planning recalibration strategy. Time thus spent at the meter recalibration may prove to have been well spent should any critical components fail in service. Operators should consider the provision of calibrated spare transducers.

6.8.9 Implementation of Calibration Data

Correction routines employed to compensate for process and environmental effects on the performance of the meter should, as far as possible, be undertaken within the flow computer and not the meter electronics. Similarly, routines adopted to generate instantaneous flow rate corrections based on multi-point calibration data should also be performed within the flow computer.

Point-to-point linear interpolation is preferred. A single point flow-weighted average may be applied if all calibration points lie within ±0.1% of their average value.

6.8.10 Pressure and Temperature Corrections

Recognised correction factors should be applied to take account of any difference between the calibration and operating conditions.

The calculation of the meter's pressure and temperatures correction factors should be traceable and auditable.

A recent North Sea Flow Measurement Workshop Paper (Whitson, R., 2008) provides guidance on the implementation of traceable correction factors.

6.8.11 Minimum Operating Pressure

Ultrasonic transducers/detectors require a minimum operating pressure for acoustic coupling. As a field declines, consideration should be given to the periodic review of performance limitations and also the most appropriate calibration range for the meter.

6.8.12 Condition-Based Maintenance (CBM)

Recent years have seen considerable advances in the operation of gas ultrasonic flow meters (USFMs); the stability of the meters themselves is better than ever before, while signal processing techniques have improved dramatically. There is now a widespread recognition that the fundamental principles of flow measurement metrology - including the idea that the uncertainty of the reference standard should be small enough (in comparison with the meter under test) as to be safely ignored – should also apply to gas USFMs. Taken together, these factors have led DECC to conclude that condition-based maintenance (CBM) of gas USFMs may be the most appropriate strategy in many instances.

However, with one exception (detailed in a paper by Peterson *et. al*. at the 2008 North Sea Flow Measurement Workshop), there has to date been no fiscal metering application in the UK where a condition-based maintenance strategy has been adopted. This may be at least partly due to the fact that 'condition-based maintenance' has been rather loosely defined, and there has been some doubt over what may or may not be acceptable to regulators and pipeline operators. DECC's expectations in this respect are necessarily generic in nature (i.e. not specific to any particular model of USFM) and should be interpreted as *minimum* requirements – DECC is likely to require more detailed information on a case-by case basis.

6.8.13 CBM - Meter Diagnostics

Gas USFM meter diagnostics may be classified depending on the type of information that they provide:

- Functional (information on the physical operation of the meter)
- Process (information on the fluid properties, flow profile, etc.)
- System Performance (information on the overall measurement system)

6.8.14 CBM - Automatic Gain Control

Automatic Gain Control (AGC) is used to make the received signal amplitude the same, irrespective of operating conditions. The main purpose of AGC is to achieve consistent zero crossing detection for accurate timing, but the actual value of the gain is also a useful diagnostic, indicating the level of attenuation along the path.

The gain depends on gas composition, pressure, velocity, path length and contamination.

6.8.15 CBM - Signal-to-Noise Ratio

Signal-to-Noise Ratio (SNR) may be used as a measure of the quality of the ultrasonic signals received. The distribution of SNRs among the transducers may indicate the source of some metering problems as they arise. For example:

- Differences between the upstream and downstream SNR suggests the possible presence of an ultrasonic noise source, often a control valve with a large pressure drop. The receiving transducers facing the noise source will have a lower SNR than those facing away from it. The presence of a control valve or other source of ultrasonic noise can be confirmed by examining the physical layout of the metering station.

- If all transducers show a low SNR, the problem is probably due to electrical noise. If only some transducer pairs show noise, and it appears on both up- and downstream signals, the transducers could be acoustically coupled to the meter body by liquid in the ports.

6.8.16 CBM - Performance

Performance is defined as the simple arithmetic ratio of pulses received to pulses transmitted.

6.8.17 CBM - Flow Profile

Depending on the meter path configuration, a number of techniques are possible whereby the Flow Profile at the meter may be determined. Measurements may include the ‘peakiness’ and symmetry of the flow profile, the degree of ‘cross flow’ and/or swirl, and a statistical estimation of the degree of turbulence of the flow.

A change in the flow profile may indicate a change in the fluid viscosity, and/or a change in the pipe wall roughness. Cross-checking with other diagnostic features may enable the Operator to determine the source of the change and to estimate its significance.

6.8.18 CBM - Speed of Sound

Speed of Sound (SOS) is the single most powerful diagnostic feature, as it may give an indication of the health of the measurement station as a whole.

The measured SOS may be continually compared with that calculated from determination of the gas composition via an on-line gas chromatograph (GC) together with an equation of state and the measured temperature and pressure of the gas. Experience suggests that deviation between the ‘measured’ and ‘calculated’ SOS of greater than 0.21% may indicate errors in the measurement of temperature and/or pressure, in the operation of the on-line gas chromatograph, or in the operation of the USFM. Cross-checking with the other diagnostic features should enable the source of any discrepancy to be determined with relative ease. Conversely, where the deviation is at its minimal level (0.21% or less), there is a very clear indication that all the elements of the system (USFM, GC, temperature and pressure measurements) are operating satisfactorily.

Comparisons of ‘measured’ and ‘calculated’ SOS is possible for each meter path, and the ‘footprint’ of these, determined at the meter’s initial calibration, may usefully be compared with that produced by the meter throughout its time in service.

6.8.19 CBM Strategy

Where it is proposed to adopt a condition-based maintenance strategy, Operators should contact DECC with details of the meter station under consideration. The following information should be presented for review:

- Meter type (including meter electronics used)
- Meter calibration history following the initial period of time-based intervention and calibration
- Details of the associated instrumentation (e.g. gas chromatograph) together with an indication of the historic stability of the relevant devices
- Typical throughput of the meter station
- The typical cost of removal and recalibration of the meter

DECC shall require to review in full the details of the meter diagnostic package to be used. The package should feature, as a minimum, continuous logging of each of the features listed in 6.8.14 to 6.8.18 above. DECC expects Operators to indicate *in advance* the range within which each of the diagnostic parameters are expected to vary, and which, if exceeded, would necessitate further investigation up to and including removal and recalibration of the USFM. (With the exception of the 'measured' v 'calculated' SOS, the relevant limits must be determined empirically; supporting evidence for these limits should be presented for review.)

DECC should also be provided with details of the proposed reporting protocol. The Operator should propose a frequency and methodology by which the data produced by the CBM system will be routinely reviewed, together with details of the action to be taken in the event of a prolonged excursion of key diagnostic parameters from the ranges defined above.

The CBM system should be capable of producing summaries of the metering system performance. DECC shall conduct reviews of the system on a regular (typically annual) basis.

Any proposed changes to the CBM system must be agreed with DECC prior to their implementation.

6.9 Recent Standards and Guidance Documents

NSFMW			
St Andrews 2010	Fosse, S. et. al.	Online gas chromatography: A technical and historical overview.	Review of relevant standards and practical experience with gas chromatography. Design and installation considerations.
St Andrews 2010	Skelton, M., Steven, Dr. R., et. al.	Developments in the self-diagnostic capabilities of orifice plate meters.	Practical application of a diagnostic technique with the aim of extending the interval between successive orifice plate inspections.
Tønsberg 2009	Steven, Dr. R.	Significantly improved capabilities of DP meter diagnostic methodologies.	Theoretical explanation of the principles behind diagnostic technique for DP meters based on additional measurement of fully-recovered pressure.
St Andrews 2008	Steven, Dr. R.	Diagnostic methodologies for generic differential pressure flow meters.	Theoretical explanation of the principles behind diagnostic technique for DP meters based on additional measurement of fully-recovered pressure.
St Andrews 2008	Peterson, S. et al	On-line condition-based monitoring of USFMs.	Development & implementation of a condition-based monitoring strategy.
St Andrews 2008	Whitson, R.	A general methodology for geometry-related pressure and temperature corrections in ultrasonic time-of-flight flow meters.	Installation effects on ultrasonic meters; temperature and pressure corrections. Traceability of manufacturers' derived calculations.
St Andrews 2008	Lunde, P.	Installation effects on the Easington ultrasonic fiscal metering station.	Installation effects on ultrasonic meters; temperature and pressure corrections.
St Andrews 2002	Hall, J et. al	Operation of ultrasonic flow meters at conditions different than their calibration.	Installation effects on ultrasonic meters.
St Andrews 2008	Hall, J et. al	When should a gas ultrasonic flow meter be re-calibrated?	Condition-based maintenance for gas ultrasonic meters.

ASTM D1945-03 (2010) Standard test method for analysis of natural gas by gas chromatography.

BS 7965 (2009) Guide to the selection, installation, operation and calibration of diagonal path transit time ultrasonic flowmeters for industrial gas applications.

ISO/DIS 17089-1 (2010) Measurement of fluid flow in closed conduits – Ultrasonic meters for gas – Part 1: Meters for custody transfer and allocation measurements.

NORSOK Standard I-104 Fiscal measurement systems for hydrocarbon gas Rev. 3, Nov. 2005.

PRCI (http://www.prci.org), Smart Ultrasonic Meter Diagnostics (2007).

7 SEPARATOR MEASUREMENT

7.1 Introduction

As indicated in Chapter 2 of these Guidelines, DECC shall consider the use of dedicated separator measurement where this is dictated by field economics.

This is often the case when new satellite fields are tied back to older 'host' facilities. New modules may be provided with dedicated separators for the satellite fields. However, a more common scenario is where a pre-existing process separator is dedicated to the new satellite field. There may be serious measurement challenges where measurement systems are retro-fitted onto separators that were not designed with fiscal metering in mind.

This chapter of the Guidelines is intended to provide Operators with an indication of DECC's expectations where fiscal measurement systems are installed on the outlets from process separators.

The use of test separators in fiscal applications is considered elsewhere in these Guidelines.

7.2 Separator Design

While the measurement on the outlets of the separators may be nominally 'single-phase', it must always be borne in mind that this may not be the case in practice. Any departure from single-phase conditions will naturally lead to a significant increase in measurement uncertainty.

Where the use of a new separator is proposed, it should be designed so as to ensure that the measurement at each outlet is single phase.

Where it is proposed to retro-fit a fiscal measurement system onto an existing separator, DECC shall require the Operator to take all reasonable steps to ensure that a single-phase flow regime is in place at each outlet.

7.3 Separator Capability

With the requirements of 7.2 in mind, a review of separator capability should take place.

Provision must be made for adequate secondary instrumentation (e.g. temperature, pressure measurement). The location of these measurements must be such that the parameters are measured at conditions representative of those at the meter.

DECC may require the Operator to perform reviews of certain critical design aspects of the proposed measurement system (for example, the use of on-line versus off-line measurement and analysis techniques) in order to determine the optimal solution from the cost/benefit standpoint.

7.4 Maintenance Frequencies

Recalibration intervals should be proposed at the PON6 stage, following the principles set out in Chapter 4 of these Guidelines.

The potential use of diagnostic facilities should be strongly considered at the design phase. This may form the basis for the adoption of a 'condition-based maintenance' strategy for one or more of the separator outlets.

Separator outlets must be provided with adequate valving and isolation so that the flow elements may be removed for inspection and/or recalibration without requiring a process shut-down.

7.5 Sampling Frequencies

Where samples are to be collected for analysis, the frequency of sampling shall be agreed with DECC prior to field start-up and shall be subject to periodic review thereafter.

7.6 Measurement Technologies

The choice of metering technology to be employed on each leg is critically important, since some technologies are more suited than others to typical separator applications.

Particular attention must be paid to the following factors at the proposed location of each meter:

- The likely flow profile

- The likelihood of two or three-phase flow occurring

The choice of meter technology for each outlet must be discussed with DECC at the PON6 stage.

7.7 Liquid Outlet Measurement

The most commonly occurring issue that must be dealt with on the liquid outlet of separators is that of gas breakout. Certain otherwise-desirable technologies (such as Coriolis meters) introduce relatively high degrees of head loss, which may be sufficient to cause the liquid to change phase at the meter.

DECC shall require Operators to take all reasonable steps to reduce the probability of such gas breakout. Measurement should take place as far as practically possible beneath the level of the separator itself, in order to maximise the static head at the flow meter. Cyclic pressure fluctuations in the pressure separator may cause corresponding cyclic gas breakout at the meter. The use of a pump to increase the pressure at the meter should also be considered.

Unless direct mass measurement (via Coriolis meter) is sufficient for allocation purposes, provision must be made for the determination of liquid density. This may be based on direct measurement or on the off-line analysis of representative samples.

Provision must be made for manual sampling at the liquid outlet. The use of an on-line flow-proportional sampler may also be required in systems with relatively high throughputs, or where the separator is to be operated in 2-phase mode. The approach to be taken shall be agreed with DECC at the PON6 stage (with reference to 7.5 above).

The water content may be determined by either by the use of an on-line water-in-oil meter, or by off-line analysis of representative samples (as discussed in 7.12).

7.8 Gas Outlet Measurement

When selecting the relevant measurement technology for the gas outlet, Operators must consider the possibility of liquid carry-over and its resultant effect on measurement uncertainty.

Provision must be made for manual sampling at the gas outlet.

Provision must be made for the measurement of gas density. The use of on-line densitometers may be precluded by the possible presence of liquids. Gas composition is more commonly determined by the off-line analysis of representative samples.

The use of on-line gas chromatography is generally precluded in separator measurement systems (unless the GC can be adequately protected from liquid carry-over). Gas composition is normally determined via the off-line analysis of representative samples, the provision of which must be considered at the PON 6 stage.

7.9 Water Outlet Measurement

Where the water measurement forms part of the fiscal allocation system, the choice of meter should be discussed with DECC.

8 MULTIPHASE MEASUREMENT

8.1 Introduction

The use of multiphase flow meters (MPFMs) in fiscal applications is now well established in the UK Sector of the North Sea. DECC has long accepted that their use in such applications is essential if the remaining reserves in the North Sea are to be exploited.

The increased use of MPFMs is attributable to this fact, and also to the undoubted improvements in meter performance that have been achieved over the last decade.

The uncertainties that can be achieved by MPFMs are typically application-dependent and may not always be quantifiable. However, measurement uncertainty can be minimised by the adoption of best practice in meter selection, maintenance, operation and verification. This section of the Guidelines outlines DECC's expectations on Operators with this overall aim in mind.

8.2 Typical Fiscal MPFM Applications

Fiscal multiphase measurement may be appropriate in production allocation applications where hydrocarbons from more than one field are commingled in a shared production facility, and where cost-benefit considerations indicate that single-phase measurement of each field cannot be not economically justified. (For a detailed explanation of the relevant considerations, please refer to Chapter 3 of these Guidelines.)

There are a number of challenges surrounding the use of MPFMs, most notably associated with sampling and meter verification.

The following table indicates some of the typical configurations in which MPFMs have been used:

	Application	MPFM Verification Method	Comments
#1	MPFM topsides on 'host' facility, measuring all wells from a single 'satellite' field.	Comparison of MPFM with test separator. 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.
#2	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.*
#3	MPFM subsea, measuring all wells from more than one 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.	Highly complex allocation issues. 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. 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*

8.3 Meter Selection

The process of meter selection is one where close co-operation between vendor and Operator is required.

The Operator should provide the vendor with details of the anticipated initial values of the following parameters:

- flow rates
- pressures
- temperatures
- composition

as well as their expected profiles throughout life of the field. This should permit the vendor to determine the size and specific configuration of the MPFM.

The actual decline in flow rate may be sufficient to require the replacement of the MPFM with a smaller model. During the field life, fluid composition may change sufficiently to necessitate a change in the meter type. (For example, gas volume fraction (GVF) will increase significantly as the reservoir pressure drops below bubble point and it may become necessary to change from a MPFM to a wet gas flow meter.)

The vendors' performance data should be compared in a 'like-for-like' manner in order that the optimal MPFM for a particular application may be identified.

It is recognised that the different multiphase measurement technologies are each better suited to some applications that to others. For example, where high-water-content wells are to be measured, the use of capacitance-based techniques to infer water content may be inadvisable since the technology may require oil-continuous flow for it to operate successfully. Equally, if the produced oil is heavy then its properties in terms of ionising radiation can approach those of water; in such cases discrimination between the oil and water using dual-energy radiation techniques may prove challenging.

All MPFMs depend on knowledge of the properties of the measured fluids. When the fluid properties change, systematic bias in the output of the MPFM may be expected unless the relevant parameters in the meter software are updated to reflect these changes. Unfortunately, it may not always be possible to detect such changes in practice – particularly in remote applications such as subsea MPFMs – since obtaining a representative sample from a multiphase stream is extremely challenging. However, some types of MPFM may be more insensitive than others to the sort of changes in fluid properties that are predicted for a given application.

8.4 Onshore MPFM Calibration

Operators are strongly urged to exercise caution in interpreting claimed MPFM uncertainties. These figures are likely to be based on empirical test data. Where such test data is used to support the decision to use a particular meter, Operators must establish that the data is not 'selective' (i.e. 'best case').

8.5 Onshore Calibration - Static Testing

The static tests performed on a MPFM vary from one model to another. However, the general purpose of such tests is to establish a reference based on a known fluid inside the measurement section of the MPFM.

This may consist of measurement of:

- Measurement of geometric dimensions
- Calibration of differential pressure cell
- Verification of γ-ray count rates in calibration fluids (oil, gas, water)

depending on the working principle of the primary measurement elements.

Such calibrations are normally carried out irrespective of the conditions in which the meter will ultimately be used.

8.6 Onshore Calibration – Flow Loop Tests

DECC may require dynamic (flow loop) tests to be carried out prior to agreeing to the use of a MPFM in a particular application. It may be appropriate to test the meter 'blind', i.e. where the vendor has no prior knowledge of the fluid conditions in the flow loop.

The aim of such tests is to compare the flow rates (oil, gas, water) indicated by the MPFM with the values measured by the reference standard flow rates for each phase over the full range of anticipated operating conditions. (Where it is not possible to test the MPFM over the full operating envelope, it may nevertheless be worthwhile to perform a dynamic calibration of the meter; this may serve as a 'dynamic functionality check'.) Where the comparison is on a volume basis, it should be referred to a common set of conditions (e.g. standard conditions) and must take account of possible transfer between phases.

The calibration fluids may be either 'process' (live crude, hydrocarbon gas, formation water) or 'model' (e.g. oil, water, nitrogen). The latter set-up is by far the most common; not only is it far less hazardous to operate but the PVT characteristics of the fluids are likely to be relatively well understood, so that it becomes possible to compare the reference measurements with those of the MPFM with minimal additional uncertainty.

8.7 Offshore Calibration – Static Testing

The aim of *in situ* static testing is to verify that the MPFM characteristics have not shown any significant change compared to the static test results obtained onshore.

Some models of meter require an initial static calibration using actual well fluids. Similar tests may be repeated at regular intervals during the meter's time in service. A comparison of these results over time serves as a useful health check.

8.8 Comparison of MPFM with Test Separator

8.8.1 When the MPFM is used to measure a well stream that is occasionally routed through the test separator, the test separator may be used to verify the performance of the MPFM.

Whenever the Operator's reverification strategy depends on periodic comparison of the MPFM with the test separator, DECC will seek assurances that all reasonable steps have been taken to minimise the uncertainty of measurement of the separator's gas, oil and water phases. DECC may require the relevant systems to be upgraded as a proviso to accepting the use of a MPFM as the fiscal meter.

8.8.2 During the comparison, the MPFM and test separator may be at significantly different conditions of pressure and temperature. Correcting the respective gas and oil volumes measured during the comparison to standard conditions requires knowledge of the hydrocarbons' composition, and involves additional uncertainty inherent in the process model. The possibility of mass transfer between phases must also be taken into account. Comparisons of the MPFM and test separator data should include the total mass measured in all three phases.

N.B. For further details of DECC's requirements in this area, please refer to the relevant section in the 'Test Separator Measurement' chapter of these Guidelines.

8.9 Sampling

Compositional analysis is invariably required in fiscal applications. In the case of production allocation using MPFMs, this is for the following reasons:

- All MPFMs depend, to a greater or lesser extent, on knowledge of fluid characteristics for their correct operation.
- PVT data may be required to model the phase behaviour of the oil and gas measured by the MPFM. This may be to test separator conditions for verification purposes (when the comparison is in volume units – see below), or to export conditions for allocation purposes.

However, obtaining a representative sample from a multiphase fluid may be difficult or impossible in practice. This is particularly true of subsea MPFM applications. There are currently no Standards which provide guidance in this area.

8.10 Summary of DECC Requirements

Where it is proposed to use a MPFM in fiscal measurement applications, DECC requires details of the following:

During the PON6 process:

- The factors taken into consideration during the meter selection process (e.g. choice of technology; sensitivity of technology to anticipated changes in fluid conditions and/or composition; sizing considerations)
- The static checks carried out on the MPFM in the factory.
- The results of the dynamic (flow-loop) testing of the MPFM. (DECC should be invited to these tests.)

- The proposed method(s) of reverification to be used once the MPFM is in service.
- The proposed method of detecting changes in the fluid composition, and in implementing such changes in the MPFM software.

While the MPFM is in service

- The results of the periodic meter reverifications.
- The changes in composition detected.

8.11 Standards and Guidance Documents

There is a noticeable lack of international Standards in the area of multiphase flow measurement. However, the following publications contain extremely valuable practical information:

'Handbook of Multiphase Metering' (NFOGM, 2005, available for free download at http://www.nfogm.no/docup/dokumentfiler/MPFM_Handbook_Revision2_2005_(ISBN-82-91341-89-3).pdf)

API RP 86 API Recommended Practice for Measurement of Multiphase Flow (2005).

API RP 85 Use of Subsea Wet-gas Flow meters in Allocation Measurement Systems (2003).

North Sea Flow Measurement Workshop papers provide a valuable source of practical guidance in the selection, operation and maintenance of MPFMs and should be reviewed by Operators considering the use of MPFMs in fiscal applications. The following table highlights some recent papers that may be of particular interest:

NSFMW	Author(s)	Title	Content
St Andrews 2010	Ross, A. & Stobie, G.	Well testing – an evaluation of test separators and multiphase flow meters.	Meter selection. Test separator design, operation and maintenance. Comparison of MPFMs and test separators.
St Andrews 2010	Scheers, L.	Challenges in multiphase and wet gas flow metering for applications with limited accessibility.	Meter selection for subsea MPFM applications. Total life-cycle costs (CAPEX and OPEX considerations). Sensitivity of MPFMs to changes in fluid properties. Flow loop testing.
Tønsberg 2009	Åbro, E., Kleppe, K., & Vikshåland, L.-J.	Recent field experiences using multiphase meters for fiscal allocation.	Comparison of MPFMs and test separators. Comparison of mass and volume flow rates. Development of MPFM 'k-factors'. Sensitivity of MPFMs to PVT data.
Tønsberg 2009	Bruvik, E. M. et. al.	Fluid characterisation in a subsea on-line multiphase fluid sampling and analysis system.	Development of a subsea multiphase sampling system.
Gardermoen 2007	Skårdalsmo, K & Åbro, E	Calibration and Verification of Multiphase Meters for Allocation Metering of the Urd Field.	Performance of subsea and topsides MPFMs in conditions of slugging flow.
Tønsberg 2005	Tierney, J. & Møksnes,P.-0.	Allocation - The Howe Measurement Challenges.	Onshore static calibration. Comparison of MPFM and test separator. Sensitivity of MPFM to PVT data. Co-operation between Operator and vendor.

9 WET GAS FLOW MEASUREMENT

9.1 Introduction

9.1.1 As with multiphase flow meters, the use of meters designed to measure 'wet gas' in fiscal applications is now well established in the UK Sector of the North Sea. DECC has long accepted that their use in such applications is essential if the remaining reserves in the North Sea are to be exploited.

9.1.2 The uncertainties that can be achieved by wet gas meters are typically application-dependent and may not always be quantifiable. However, measurement uncertainty can be minimised by the adoption of best practice in meter selection, maintenance, operation and verification. This section of the Guidelines outlines DECC's expectations on Operators with this overall aim in mind.

9.1.3 Where multiphase flow meters are used in 'wet gas' mode, the same considerations apply regarding meter selection, testing and calibration – Operators should consult Chapter 8 of this document for Guidance in this area.

This chapter is intended to provide Operators with guidance on the use of generic (non-manufacturer-specific) differential pressure meters in fiscal wet gas applications.

The publication of the results of research work at North Sea Flow Measurement Workshops and elsewhere is an invaluable source of information, particularly in the area of wet gas measurement where the information is likely to be available via this route many years before it appears in a standard.

9.2 Differential Pressure Meters

When wet gas flow passes through a differential pressure meter, the presence of liquid results in an increase in the measured ΔP. As a result, the meter over-estimates the gas flow rate. The degree of over-estimation depends on a number of factors – the Lockhart Martinelli parameter, the gas to liquid density ratio (essentially the operating pressure), the gas densiometric Froude number and the water-liquid ratio.

Venturi meters are most commonly used in wet gas applications. A number of correlations have been developed in order to correct the over-reading of Venturi meters in the presence of liquid.

Recent work [Steven 2011] has highlighted the fact that despite the recent lack of attention on orifice plate response to wet gas flows, there is in fact much to recommend their use. Provided the orifice plate does not sustain damage, its response is repeatable, reproducible and therefore predictable. Flow visualisation studies have shown that the risk of liquid being trapped behind the orifice plate has been over-stated. Furthermore, a correlation has been developed for 2" to 4" meters that is essentially independent of β-ratio.

9.3 Wet Gas Correlations

An understanding of the origin of wet gas correlations is important, as it identifies the range of parameters within which they were determined.

Perhaps not surprisingly given the technical nature of the subject, there is considerable misunderstanding around the derivation and applicability of many of the terms routinely used in wet gas correlation theory [Steven *et. al.* 2007].

The original Lockhart-Martinelli parameter was derived in the 1940s and was never intended for use at the Reynolds numbers typical of modern-day natural gas production flows.

In a 1962 paper Murdock described the performance of orifice plate meters in general two-phase flow. He derived a correlation that is dependent on the specific meter geometry and is therefore not suitable for general use. However, he was able to demonstrate that the over-reading of differential flow meters in wet gas applications is a function of Lockhart-Martinelli parameter.

During the 1960s and 70s Chisholm published a general two-phase flow correlation for orifice plate meters that has been the basis of many subsequent wet gas correlations. He showed that the degree of over-reading of orifice meters in wet gas flow is dependent on gas-to-liquid density ratio, as well as the Lockhart-Martinelli parameter. His work defined a correlating parameter that can be used to describe the liquid-to-gas ratio of any wet gas flow. It is independent of pipe roughness, and does not depend on specific meter geometry.

Steven *et. al*. [2007] suggested that this Chisholm parameter should supersede the old Lockhart-Martinelli parameter, but suggested the retention of the old name in view of its entrenched position within industry. This modified Lockhart-Martinelli parameter, referred to as XLM, ought now to become standard. It is defined as follows:

$$X_{LM} = \frac{m_l}{m_g}\sqrt{\frac{\rho_g}{\rho_l}} = \frac{Q_l}{Q_g}\sqrt{\frac{\rho_l}{\rho_g}}$$

This new definition allows us to define the upper boundary of wet gas flow as follows:

$$X_{LM} \cong 0.3$$

9.4 Venturi Meter Correlation

9.4.1 In 1997 de Leeuw published a correlation that has since been widely used in North Sea applications. This introduced a further dependency term, the gas Froude number. de Leeuw's correlation was derived using a 4", 0.4β Venturi tube, with diesel oil and nitrogen as the test fluids. Approximately 100 test points were covered, with pressures ranging from 15 to 90 bar and gas volume fractions ranging from 4% to 10%.

Stewart [2003] showed that the wet gas over-reading also depends on the meter's β-ratio.

Reader-Harris *et. al*. [2006] and Steven [2006] have independently demonstrated that the response of differential pressure wet gas meters is further influenced by the physical properties of the liquid.

9.4.2 Reader-Harris and Graham [2009] further developed the Chisholm model to take account of the physical properties of the liquid.

At the time of writing, this correlation is regarded as the best available, since it covers a wider range of meter parameters and wet gas conditions than any of its predecessors, and DECC strongly encourages its use in new fiscal wet gas applications.

9.5 Orifice Plate Correlation

Steven [2011] has developed an orifice meter correlation for 2" to 4" meters which is applicable over a wide β-ratio range ($0.25 \leq \beta \leq 0.73$).

9.6 Extrapolation of Wet Gas Correlations

Extrapolation of these correlations outwith the range of these parameters carries the risk that measurement uncertainty will be increased by an unknown amount.

This is often stated explicitly by the authors of the correlations themselves, for example de Leeuw [1997]:

"…empirical relationships cannot be applied outside their corresponding experimental range."

In general, differential pressure meters in wet gas applications behave more like their single-phase equivalents as pressure is increased. Therefore the above principle is particularly true where correlations are applied to pressures below those used in their derivation.

9.7 Determination of Gas and Liquid Density

The liquid and gas densities may be determined by laboratory analysis of representative samples. Sampling of wet gas flows is not trivial and careful consideration must be given to the design and operation of the sampling system. The use of fully-automated flow-proportional sampling systems is generally precluded by the marginal nature of wet gas field developments, so that intermittent manual sampling is the most commonly-employed tactic. In such cases, the question of sampling frequency must be carefully considered.

There are specific practical issues arising from the nature of many of the nominally 'dry' gas fields in the southern sector of the UK North Sea. Many of these have been shown to begin to produce significant quantities of liquid as they mature. In such cases, identifying the point at which liquid production begins is key. In cases where fields are developed via 'normally unattended' installations (NUIs), it may be necessary to schedule visits for the specific purpose of obtaining representative samples. Where this is not practicable, process simulation may be an acceptable alternative; a decision to this end shall be made following discussion with DECC.

9.8 Determination of Liquid Content

A number of techniques have been developed for the determination of the flow rate of the liquid component of a wet gas flow. For example, tracer techniques have been used with some success.

It may be possible to determine the liquid content from the analysis of representative samples (as described in 9.7 above).

An estimate of liquid content can potentially be obtained when it is possible to route the flow through a test separator.

In wet gas applications the pressure loss across a Venturi tube is generally much greater than in analogous dry gas situations, and is a function of the wetness of the gas. Recent work by Reader-Harris and Graham [2009] has further developed the established technique of using the pressure-loss across a Venturi tube to determine the 'wetness' of a wet gas flow. This has the potential to eliminate the need for a separate technique to determine water content.

The proposed method to determine liquid content should be discussed with DECC at the PON6 stage.

9.9 Comparison of Wet Gas Meter with Test Separator

It is recognised that in many wet gas applications it may not be possible to place the wet gas meter in series with the platform test separator. However, when this is achievable DECC shall normally require routine comparisons to take place.

In such cases the procedures to be followed are the same as those described in the analogous section in the chapter on Multiphase flow metering (ref. sections 8.10 and 8.11). Similarly to the scenario with multiphase meters, in such cases DECC may also require the Operator to review and if necessary improve the single-phase measurement systems on the test separator outlets (see the chapter on Test Separator measurement for further guidance).

9.10 Summary of DECC Requirements

Where it is proposed to use employ wet gas metering techniques in fiscal applications, DECC requires details of the following:

During the PON6 process:

- The factors taken into consideration during the meter selection process (e.g. suitability of available correlations in view of likely operating conditions)
- The proposed method for estimation of liquid content.
- The proposed method of meter reverification; feasibility of comparison with test separator.

While the Wet Gas Metering system is in service

- The results of the periodic meter reverifications.
- The results of the tests to determine liquid content.

9.11 Standards and Guidance Documents

There is a noticeable lack of international Standards in the area of wet gas flow measurement. However, the following publications contain extremely valuable practical information:

NSFMW	Author(s)	Title	Content
Tønsberg 2011	Steven, Dr. R.	Horizontally-installed orifice plate response to wet gas flows.	The use of orifice plates in wet gas metering applications.
Tønsberg 2009	Reader-Harris, M. & Graham, E.	An improved model for Venturi tube over-reading in wet gas.	A new wet gas correlation. Method to estimate liquid content from measurement of pressure loss.
Gardermoen 2007	Steven, Dr. R.	A discussion on wet gas flow parameter definitions.	Clarification of the definition of some of the key parameters in wet gas measurement.
St Andrews 2006	Reader-Harris, M et. al.	Venturi tube performance in wet gas using different test fluids.	Sensitivity of wet gas measurement to liquid properties.
St Andrews 2006	Steven, Dr. R.	Horizontally installed differential pressure wet gas meter performance review.	Sensitivity of wet gas measurement to liquid properties.
Tønsberg 2003	Stewart, D.	Venturi meters in wet gas flow.	β-ratio effect on wet gas over-reading.

UK National Measurement System Guidance Note – Investigation of Venturi Flow Meter Performance in Wet Gas using Different Test Fluids (NEL, 2005) – available at www.tuvnel.com

10 TEST SEPARATOR MEASUREMENT

10.1 Introduction

The use of test separator measurement systems for fiscal purposes is possible under either of the following scenarios:

- Where the agreed Method of Measurement for the relevant field(s) is 'Flow Sampling' (as defined in Chapter 3), i.e. where fluids are allocated to one or more licensed areas on the basis of periodic single-phase measurements on the test separator.

- Where the agreed Method of Measurement for the relevant field(s) is 'Multiphase Metering' (as defined in the chapter 'Measurement Approach), with the multiphase meter (MPFM) periodically verified against the test separator.

  Note: Wet Gas metering may be considered as a subset of Multiphase Metering for this purpose.

Flow meter performance during well testing may fall far short of the levels potentially achievable in single-phase laboratory applications. This chapter of the Guidelines sets out DECC's expectations on Operators in order that these uncertainties may be minimised.

10.2 Test Separator Design

In either of the two scenarios described in the Introduction, the test separator is unlikely to have been designed with fiscal service in mind. It may be desirable to upgrade the test separator instrumentation, and indeed DECC will normally insist on a full review of test separator capability before agreeing to the 'Flow Sampling' or 'Multiphase Meter' measurement approaches for a given field.

The relevant considerations in such circumstances are similar to those already described for dedicated process separators in Chapter 7. However, it must be borne in mind that the measurement challenges are likely to be more pronounced in Test Separator applications.

10.3 'Flow Sampling' – Well Test Procedures

Where 'Flow Sampling' is the agreed method of measurement, an agreed frequency of well tests shall be agreed with DECC and stated in the PON6. While DECC acknowledges that there are likely to be considerable pressures on test separator use, Operators must make every effort to adhere to the agreed frequencies and must inform DECC whenever 2 or more successive tests have not taken place.

DECC shall also require the Operator to carry out a review of the relevant well-test procedures. These should include details of:

- The planned duration of the well tests (this should take into account the peculiarities of individual wells, e.g. long-distance tie-backs may require longer for the flow to stabilise).

- The method by which well test details (e.g. well-head flowing pressure, choke position) shall be recorded.

- The method by which fluid composition shall be determined during the well test.

The relevant procedures should be made available for review by DECC.

10.4 Multiphase Measurement – MPFM/Test Separator Comparison Procedures.

Where the agreed Method of Measurement is 'Multiphase Metering' with the multiphase meter (MPFM) periodically verified against the test separator, an agreed frequency for the relevant comparisons shall be agreed with DECC and stated in the PON6. While DECC acknowledges that there are likely to be considerable pressures on test separator use, Operators must make every effort to adhere to the agreed frequencies and must inform DECC whenever 2 or more successive planned comparisons have not taken place.

DECC shall also require the Operator to draw up procedures for the comparison. These should include details of:

- The flow stability criteria required for the test to take place
- The planned duration of the comparisons.
- The basis on which the comparison shall be made (e.g. mass, volume at standard conditions – per phase, and total).
- The method by which fluid composition shall be determined during the comparison.

The relevant procedures should be made available for review by DECC.

10.5 Verification of Test Separator Measurement

On a given production installation, it is normal practice to test all wells on a periodic basis, whether part of a 'Flow Sampling' regime or not, for the purpose of reservoir management. Petroleum from these wells is also measured via the various export and disposal systems on the installation – oil and gas export metering, fuel gas, flare gas, overboard water, etc.

The degree to which the sum of well flows agrees with the sum of the export/disposal quantities may serve as an indication of the accuracy of the well test system. Ideally, the figures should be compared on a mass balance, since the additional uncertainty inherent in process modelling is thereby avoided.

Where 'Flow Sampling' is the agreed method of measurement, DECC expects Operators to carry out regular checks of the mass balance across the relevant installation (this is in any case Good Oilfield Practice, since reservoir models depend on good well test data for their successful operation), and to make the results available for review.

10.6 Standards and Guidance Documents

The following documents contain valuable guidance on the design and operation of the relevant measurement systems and their review is strongly recommended:

API RP86 (Recommended Practice for Measurement of Multiphase Flow, 2005)

Ross, A. & Stobie, G.; *Well testing – an evaluation of test separators and multiphase flow meters;* 28th North Sea Flow Measurement Workshop, St Andrews 2010.

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