Oil & Gas Authority

OGA Measurement Guidelines 2020

January 2020

Contents

1. Introduction

1.1 The Oil & Gas Authority

1.1.1 The Energy Act 2016[1] created the Oil & Gas Authority ('OGA') as an independent regulator and transferred some of the Secretary of State's regulatory responsibilities, including petroleum licensing, to the OGA.

1.1.2 The role of the OGA is to regulate, influence and promote the upstream oil and gas industry in the UK so that it achieves the statutory principal objective of maximising economic recovery from the UK's oil and gas resources (MER UK). (See https://www.ogauthority.co.uk/ for further information.)

1.1.3 Details of the UK's fiscal regime for upstream oil and gas activities may be found at the following URL: https://www.gov.uk/topic/oil-and-gas/finance-and-taxation

1.2 Status and Purpose of the Guidelines

1.2.1 Production licences contain provisions in relation to the measurement of petroleum including a requirement that: "The Licensee shall measure or weigh by a method or methods customarily used in good oilfield practice and from time to time approved by the OGA all petroleum won and saved from the licensed area."

1.2.2 The purpose of these Guidelines is to set out the OGA's expectations as to what will generally constitute 'good oilfield practice' for the full range of fiscal measurement scenarios that are likely to be encountered in practice. The Guidelines also set out the procedure that licensees should follow to gain the OGA's approval of their methods for petroleum measurement.

1.2.3 While responsibility to comply with the licence obligations in relation to the measurement of petroleum rests with the licensee, the OGA recognises that in practice these matters may be undertaken by the operator, on behalf of the joint venture. The OGA therefore expects operators to similarly adhere to the principles of 'good oilfield practice' and the terms 'licensee' and 'operator' are used interchangeably in these Guidelines.

1.2.4 With the exception of Chapter 13, these Guidelines apply to measurement systems used to determine quantities of petroleum won and saved from licensed areas both onshore and offshore in the UK.

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

1.2.6 The Guidelines are not a substitute for any regulation or law and are not legal advice. They do not have binding legal effect. Where the OGA departs from the approach set out in the Guidelines, the OGA will endeavour to explain this in writing to the relevant Operator or licensee.

1.2.7 The Guidelines will be kept under review and may be amended as appropriate in the light of further experience and developing law and practice, and any change to the OGA's powers and responsibilities.

1.3 The OGA's Metering Team

1.3.1 The OGA's Metering Team helps to ensure the delivery of the MER UK objective by taking a risk-based approach to the regulation of fiscal oil and gas measurement. The OGA's focus will be on the areas of greatest fiscal risk to the UK Exchequer, including:

- Points of sale of hydrocarbons produced on the UK Continental Shelf
- Measurement and allocation in shared transportation systems containing non-UKCS (principally, Norwegian) hydrocarbons

[1] http://www.legislation.gov.uk/ukpga/2016/20/contents/enacted

1.3.2 At the same time, the OGA encourages Operators to themselves adopt risk-based approaches in the design and day-to-day running of their measurement stations.

1.3.3 In addition, the OGA's Metering Team is taking an increased interest in measurement of flow rates from individual wells for field- and reservoir-management purposes.

1.4 Contact Details

1.4.1 Contact details for the OGA's Metering Team are to be found at the following URL: https://www.ogauthority.co.uk/exploration-production/production/petroleum-measurement/

1.4.2 General communications to the OGA's Metering Team should be sent to: metering@oga.co.uk.

2. Overview of OGA Regulation of Fiscal Oil and Gas Measurement and Allocation

2.1 Pipeline Export Systems

2.1.1 Most hydrocarbons produced on the UKCS are exported to market via shared transportation systems (pipelines), with the quantities measured at the terminal being allocated to each entry point on the basis of measurements of quality and quantity at the respective metering stations.

2.1.2 The design and operating requirements at the terminal and at the pipeline entry points are typically determined by the relevant pipeline operating agreement, covering areas such as:

- measurement uncertainty
- sampling and analysis procedures for the determination of hydrocarbon quality (for liquid hydrocarbons) or energy value (for gaseous hydrocarbons)
- determination of water content (for liquid hydrocarbons)
- calibration of primary and secondary instrumentation
- periodic inspection of the measurement station by an independent authority

2.1.3 From time to time, the OGA may review the management of measurement activities by pipeline operators, with particular emphasis on the following areas:

- pipeline balance
- scheduling and follow-up of independent audits of measurement stations at pipeline entry points
- dispensation and deviation management
- adoption of risk-based versus time-based maintenance strategies

2.2 Allocation Measurement

2.2.1 Further to the allocation of production to primary entry points, secondary and even tertiary sub-allocation of commingled production to licensed areas may take place. There is typically no pipeline-wide requirement on standards at these secondary and tertiary measurement points; instead, the method of measurement and allocation is agreed between the Operators and Licensees of the relevant fields and the OGA, at the Petroleum Operations Notice 6 (PON 6) stage (see Chapter 3). This document contains guidance on the approaches that are likely to be acceptable under such scenarios, in the chapters on separator, test separator and multi-phase/wet gas measurement.

2.3 Offshore Loading Systems

2.3.1 Where liquid hydrocarbons are exported direct to market with the point of sale at the port of discharge, the OGA is generally content to rely on the terminal Outturn figures. Operators are asked to provide the OGA with the cargo transfer figures at key points in the value chain (See chapter 8).

2.4 OGA Tier Zero Reviews

2.4.1 Operators' performance in managing the operation of their fiscal measurement stations is part of the OGA's Stewardship Review process[2]. A number of key performance indicators, for example:

- performance at the OGA inspections
- progress in closing out points raised during inspections by the OGA or independent pipeline auditors
- progress in closing out dispensations within initially-agreed timeframes) are fed into the Tier Zero review

[2] https://www.ogauthority.co.uk/media/3540/stewardship-review.pdf

2.5 Additional Guidance

2.5.1 Valuable guidance on best practice in measurement and allocation applications is provided by the following:

(i) The proceedings of the annual North Sea Flow Measurement Workshops[3].

(ii) The Energy Institute publications in the 'Hydrocarbon Management' series. Details of these can be found at the following URL: https://publishing.energyinst.org/topics/hydrocarbon-management

[3] https://nfogm.no/documents/north-sea-flow-measurement-workshop/

3. Petroleum Operations Notice 6 (PON 6) Process

3.1.1 Guidance on the OGA's Field Development Plan (FDP) expectations is available on the OGA website[4]

3.1.2 The FDP submission may include a basic statement on the proposed method of measurement for the relevant field. In addition to the FDP, an additional document, known as the Petroleum Operations Notice 6 (PON 6), is required.

3.1.3 The preparation of a PON 6 submission is an iterative process, the purpose of which is to establish in writing an agreed method of measurement for the field.

3.1.4 The final content of the PON 6 must be agreed with the OGA prior to the start of production from the relevant field.

3.1.5 The level of information required by the OGA depends on the scale of the field development under consideration and on the proposed hydrocarbon export route.

3.1.6 Where the hydrocarbon export route is directly into a shared transportation system, the method of measurement is likely to be determined by the need to comply with the pipeline entry specifications. *In such cases, the OGA will generally restrict its regulatory input to ensuring that the Licensee complies with the relevant pipeline entry requirements*

3.1.7 For new field developments where the fiscal measurement point will be a secondary or tertiary allocation point, the OGA shall at each stage in the procedure seek assurances that the proposed method of measurement is acceptable to the other interested parties. In assessing the exposure in more complex multiple-entrant allocation systems, it may be useful to consider the resultant uncertainties not just in field terms, but also in terms of the financial exposure to each equity holder in the system.

3.2 Method of Measurement

3.2.1 Direct measurement approaches may be regarded as adopting the following hierarchy (in ascending order of measurement uncertainty):

(i) Continuous single-phase measurement of each phase, post-separation, in dedicated meter runs designed to minimise measurement uncertainty.

(ii) Continuous, nominally single-phase, measurement of each phase on the oil, gas and water off-takes of a dedicated separator.

(iii) Continuous multiphase or wet gas measurement via a dedicated flow meter, installed either topsides or subsea multiphase.

(iv) 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' – 'flow sampling'.

3.2.2 In some circumstances, a 'by difference' solution may be appropriate, provided the field in question is a relatively large proportion of the commingled total.

3.2.3 The optimal measurement solution is one where the desirability of low measurement uncertainty is weighed against the economics of the field development in question.

3.3 Initial Meeting

3.3.1 For a new field development, the Licensee should present its proposals to the OGA 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 the OGA.*

[4] https://www.ogauthority.co.uk/exploration-production/development/field-development-plans/

3.3.2 In considering the proposed measurement approach, the OGA will take account of the specific economic and technical aspects of the proposed field development. At this stage Licensees should provide the following information (together with any other information requested by the OGA):

- The reserves and anticipated production profile of the field.
- A process flow diagram, 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 approximate measurement uncertainty figure.
- Details of the proposed method and frequency of re-verification of the metering technology. Where it is intended to adopt elements of a 'condition-based maintenance' strategy, this should be considered at the design stage as it may necessitate the use of additional measurement points and/or dual instrumentation.

3.3.3 Further to the initial meeting, the OGA may require Licensees to carry out a cost-benefit analysis so that the optimal method of measurement may be determined. In such cases, the cost-benefit analysis must be submitted at a sufficiently early stage that none of the options under consideration would involve a delay in first oil and/or gas.

3.4 Approval to Proceed with Design

3.4.1 Once the measurement approach has been agreed in principle, the Operator will be given approval to proceed with the detailed design. The approval will normally take the form of a note making reference to material presented by the Operator during the initial meeting, and/or any subsequent cost-benefit analysis.

3.5 Testing and Calibration Activities

3.5.1 Prior to its installation and on-site commissioning, the Operator should be able to demonstrate to the OGA, if requested, that the critical elements of a fiscal measurement station have been tested and demonstrated to be fully operational, with all necessary functionality and all relevant calculations being performed to within the required tolerances.

3.5.2 The OGA should be informed of the dates of all such testing activities. Exceptionally, representatives from the OGA may choose to attend. At least 2 weeks' notice should be given to the OGA of the relevant dates.

3.5.3 The OGA may request to be provided with calibration reports for primary flow elements.

3.6 Final PON 6 Submission

3.6.1 The final PON 6 submission should include, as a minimum, the following supporting information:

- A statement of the method of measurement to be adopted (see 2.2. above).
- A process flow diagram, indicating the location of the proposed metering and sampling points.
- Piping and instrumentation diagrams showing the dimensions and configuration of the pipework immediately upstream and downstream of the metering and sampling systems.
- Proposed initial frequencies for the recalibration of critical flow elements.

3.7 Formal Non-Objection from the OGA

3.7.1 Subject to the satisfactory completion of the PON 6 process (including any follow-up information requested by the OGA), the Operator will receive a letter of 'non-objection' to the proposed method of measurement from the OGA.

4. General Operating Principles

4.1 Risk-Based Maintenance Strategies

4.1.1 The OGA expects Operators of both pipelines and individual measurement stations to be open to the adoption of a risk-based approach to maintenance.

4.1.2 In such an approach, Operator experience is used to assess the likely overall effect, in terms of financial exposure, of increased uncertainty in measurement at either the primary or the secondary element, and to balance this against the cost of its mitigation by re-calibration.

4.1.3 In considering the effect of increased measurement uncertainty, it is important use a statistical approach, rather than simply multiplying the uncertainty figure by the value flow rate, which will result in an over-estimation of financial exposure.

4.1.4 A detailed risk-based approach is described in a number of papers[5,6,7] from North Sea Flow Management Workshops[8]

[5] Pashnina, N & Daniel, P. “Determination of Optimal Calibration Intervals – A Risk-Based Approach.” 34th International North Sea Flow Measurement Workshop, St. Andrews 2016.

[6] Stockton, P. “Cost benefit analyses in the design of allocation systems.” 27th International North Sea Flow Measurement Workshop, Tønsberg 2009.

[7] Sætre, C. et. al “A new methodology for cost-benefit risk analysis of oil metering system lay-outs.” 33rd International North Sea Flow Measurement Workshop, Tønsberg 2015

[8] https://nfogm.no/documents/north-sea-flow-measurement-workshop/

5. OGA Inspection of Fiscal Oil and Gas Measurement and Allocation Systems

5.1.1 Under the terms of the licence, the OGA has a right to inspect any measurement station used to determine quantities of hydrocarbon won and saved from a licensed area on the UKCS. However, in keeping with the objective of MER UK, the OGA's inspection programme is generally targeted at the areas of greatest financial risk to the UK [Exchequer], including:

(i) Points of sale at onshore terminals in the UK

(ii) Measurement stations at entry points on shared transportation systems containing non-UKCS hydrocarbons (principally, oil and gas pipelines shared with hydrocarbons originating on the Norwegian continental shelf)

(iii) Measurement stations on trans-median or trans-boundary field developments

5.1.2 For measurement stations that do not lie in the above categories, the OGA will generally rely on the measures put in place by pipeline Operators to ensure that the standards of 'good oilfield practice' are maintained.

5.1.3 The OGA may request access to reports produced on the key measurement stations by independent inspectors appointed by the pipeline Operator. (Several pipeline Operators already provide the OGA with this information on a routine basis.)

5.2 Inspection Planning

5.2.1 The OGA gives Operators as much notice as possible of its intent to carry out inspections, and will endeavour to co-operate with Operators' offshore planning schedules. In return, the OGA expects Operators to treat inspection dates, once agreed, as firm commitments.

5.2.2 A typical inspection of an offshore installation is of 2-3 nights' duration. Operators are expected to co-operate in arranging inspections within a window of Monday-Wednesday/Thursday or Tuesday-Thursday/Friday.

5.3 Inspection Format and Follow-Up

5.3.1 During the inspection, the OGA will seek to establish the extent to which the Operator of the measurement station is in compliance with the relevant pipeline requirements, and to assess the degree of control with which the measurement station is being managed.

5.3.2 An overall 'score' for the measurement station will be determined, based on two elements:

- Status during the inspection
- Perceived risk of mis-measurement

5.3.3 Following the inspection, the OGA will report its findings to the Operator. An opportunity for feedback will be given to the Operator, and timeframes for the resolution of the identified issues shall be agreed.

5.4 UK/Norway Memorandum of Understanding

5.4.1 The UK has a long-standing Memorandum of Understanding (MoU)[9] with the Government of Norway, setting out procedures for joint surveillance activities on measurement stations of common interest; an up-to-date list of these measurement stations is maintained in the associated Annex 1.

5.4.2 As per the terms of the MoU, from time to time, the measurement stations listed in Annex 1 will be inspected jointly by the OGA and representatives of the Norwegian Petroleum Directorate.

[9] https://www.ogauthority.co.uk/exploration-production/production/petroleum-measurement/

6. Dispensation and Deviation Management

6.1 Dispensations

6.1.1 During the operational life of a fiscal measurement station, significant departures from the normal operating conditions may be expected to arise. The need to maintain measurement integrity must be balanced against the potential cost of remedial action.

6.1.2 In cases where the situation at a primary allocation point is expected to last more than a few days, a dispensation should be obtained from the relevant pipeline Operator. This should indicate the timeframe within which the matter is expected to be resolved.

6.1.3 Where there is evidence of poor dispensation management on the part of the Operator of a field or fields, the OGA may intervene in order to establish a course of remedial action.

6.2 Deviations

6.2.1 Where dispensations have been agreed, the aim is to ensure that appropriate remedial action takes place within agreed timeframes. There may be instances, particularly towards the end of field life, where remedial action is no longer economically justified. Where such a situation arises at a primary allocation point, a permanent dispensation should be agreed with the relevant Pipeline Operator.

6.2.2 Operators of primary allocation systems should be able to demonstrate that they have in place adequate systems of oversight so that such departures from normal operating practice may be detected and managed appropriately.

7. OGA Pipeline Reviews

7.1.1 From time to time, the OGA will meet with the Operators of shared transportation systems on the UKCS, in order to review:

- The performance of the individual measurement stations on the pipeline, with particular emphasis on those with relatively high throughputs
- The pipeline Operator's management of measurement on the pipeline

7.2 Metering Station Performance

7.2.1 The review of the performance of metering stations at primary entry points will cover the following areas:

- Significant mis-measurements raised during the previous twelve months
- Active and historic dispensations
- Independent inspection findings
- Meter performance and calibration history
- Sampling performance (for liquid hydrocarbons)
- Gas chromatograph performance (for gaseous hydrocarbons)
- Progress in closing out dispensations and independent inspection findings within agreed timeframes.
- Maintenance strategy

7.2.2 Where there is evidence of poor practice, the OGA may pursue the matter with the Operator of the relevant measurement station.

7.3 Pipeline Management

7.3.1 As stated in paragraph 7.1.1, for shared transportation systems holding hydrocarbons originating solely on the UKCS, the OGA will generally rely on the pipeline Operators to ensure that 'good oilfield practice' is followed at the primary allocation points.

7.3.2 On at least an annual basis, the OGA will meet with pipeline Operators to review aspects of their management of measurement including:-

- Pipeline balance
- Scheduling of independent inspections of measurement stations
- Dispensation and deviation management

7.3.3 The OGA may ask pipeline operators to assess entrants' performance on the basis of a number of key performance indicators, indicating, for example:

- Progress in closing out points raised during independent inspections
- The percentage of dispensations closed out within initially-agreed timeframes
- The number of significant mis-measurements raised during the previous twelve months.

7.3.4 The use of 'dashboards', or equivalent, to summarise the performance of the measurement stations at primary entry points, is encouraged.

7.3.5 Where Operators of metering stations at primary entry points have concerns over aspects of pipeline regulation and these cannot be resolved by dialogue with the respective pipeline authority, the matter may be raised with the OGA. The OGA will consider the matter and may approach the pipeline authority to discuss the matter further.

8. Offshore Loading Systems

8.1.1 The majority of the liquid hydrocarbons produced on the UKCS is exported from production facilities via shared pipelines. However, a significant proportion is exported direct to market via shuttle tankers.

8.1.2 The point at which the sale of oil takes place is a commercial decision on the part of the Operator. It may be either:

a) at the point of offshore loading, based on the Bill of Lading, or (more commonly)

b) at a 'port of discharge', based on the Outturn

In the case of a), the fiscal measurement takes place during the transfer of oil to the shuttle tanker. This is generally achieved using measurement systems that are designed to custody transfer standards. The OGA may from time to time inspect such measurement stations to ensure that appropriate measurement standards are being maintained.

In the case of b), the fiscal measurement is likely to be beyond the jurisdiction of the OGA. *It is with this scenario that the remainder of this chapter of the Guidelines is concerned.*

The OGA should be informed of the intended location of the point of sale at the PON 6 stage, since this essentially determines the measurement and reporting requirements.

Definitions

Arm's Length Sale	As defined in Para. 1 of Schedule 3 to the Oil Taxation Act 1975 and the provisions of section 282 of the Corporation Tax Act 2010, a sale is Arm's Length if, and only if: (a) the contract price is the sole consideration for the sale; (b) the terms of the sale are not affected by any commercial relationship (other than that created by the contract itself) between the seller or any person connected with the seller and the buyer or any person connected with the buyer; and (c) neither the seller nor any person connected with him has, directly or indirectly, any interest in the subsequent resale or disposal of the oil or any product derived therefrom.
Bill of Lading	The quantity delivered from the offshore installation to the shuttle tanker. This is normally determined on the basis of measurements made on the offshore installation during the transfer to the shuttle tanker.
Ship's Figures	The quantity held on the ship, determined immediately following the transfer from the offshore installation, and again immediately prior to offload at the port of discharge.
Outturn	The quantity measured at the port of discharge.
Vessel Experience Factor	A correction factor applied to the Ship's Figures, based on a statistical analysis of historic discrepancies from onshore (Outturn) values.

8.2 OGA Measurement Expectations

8.2.1 Measurement of quantities of oil exported direct to market is required for the following reasons:

(i) As referred to in paragraph 1.2.1 , there is a licence requirement to determine quantities won and saved from the licensed area, using a method of measurement consistent with 'good oilfield practice', and agreed at the PON 6 stage.

(ii) There is a fiscal requirement to determine quantities of oil sold, since this forms the basis of the calculation of profit from offshore operations, which is subject to Corporation Tax and the Supplementary Charge.

8.2.2 Having reviewed Bill of Lading versus Outturn data from over 500 cargoes delivered to ports of discharge from the UKCS during 2014-2019, the OGA is currently satisfied that there is no evidence of any systematic bias in the determination of Outturn quantities. Moreover, provided there is good agreement between the Outturn figure and the Ship's Figures immediately prior to offload, cargoes are typically accepted without reference to the Bill of Lading.

8.2.3 Therefore, for cargoes sold on the basis of the Outturn, the OGA does not set any expectation on the uncertainty with which the Bill of Lading is to be determined.

8.2.4 The interests of all parties (including the Operator) at the port of discharge are normally represented by an Independent Cargo Inspector whose task it is to ensure that correct procedures are followed. A Marine Cargo Expeditor may also be appointed by the Operator to represent their interests at the port of discharge.

8.2.5 Where the sale of hydrocarbons is 'Arms' Length', the interests of Operator and Government are aligned, since it is in the interests of both to ensure that the Outturn is maximised. Where the sale is not at Arm's Length, the OGA may require further details of the independent scrutiny of the quantity of oil declared to have been sold.

8.3 OGA Reporting Requirements

8.3.1 The American Petroleum Institute (API)[10] Manual of Petroleum Measurement, Chapter 17 (Marine Measurement) recommends that Operators, as part of their surveillance of the cargo transfer process, track critical parameters at four key points. These are:

- The total calculated volume delivered from the offshore installation (Bill of Lading).
- The Ship's Figures, immediately post transfer from the offshore installation.
- The Ship's Figures, immediately prior to offload at the port of discharge.
- The total calculated volume measured at the port of discharge (Outturn).

8.3.2 The OGA requires that the following parameters are reported at each of the above points:

- Gross Standard Volume.
- Net Standard Volume.
- Sediment and Water.
- Standard density.

in order that the integrity of the overall cargo transfer process may be assessed.

8.3.3 For each cargo transferred, the following information should be provided:

- A numeric cargo identifier.
- The date of the offload to the shuttle tanker.
- The identity of the shuttle tanker.
- The location of the port of discharge.

8.3.4 In addition, the OGA requires the following information for each offload:

- Was a 'Vessel Experience Factor', or equivalent, used in the determination of the Ship's Figures?
- Did the sale take place at 'Arm's Length'?
- Is an independent cargo inspector's report available?
- Is a marine expeditor's report available?

[10] www.api.org

8.3.5 On a quarterly basis, Operators are expected to populate the standard OGA pro-forma[11] with the above information and to send it to the OGA at the E-mail address metering@ogauthority.co.uk.

8.3.6 The OGA uses this pro-forma to populate its own database of cargo offloads from the UKCS to onshore ports of discharge. Operators may occasionally be requested to provide further details, for example where ship-to-ship transfers are involved, or where there is a consistent negative discrepancy between the offshore figures (Bill of Lading and/or Ship's Figures) and the Outturn.

[11] https://www.ogauthority.co.uk/exploration-production/production/petroleum-measurement/

9. Production Separator Measurement for Allocation Purposes

9.1 Introduction

9.1.1 The OGA will consider the use of dedicated separator measurement for fiscal purposes 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 field. However, a more common scenario is where a pre-existing process separator is dedicated to the new field. There may be serious measurement challenges where measurement systems are retro-fitted onto separators that were not designed with fiscal metering in mind.

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

9.1.3 The use of test separators in fiscal applications is considered elsewhere in Chapter 10.

9.2 Separator Design

9.2.1 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 may lead to a significant increase in measurement uncertainty.

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

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

9.3 Separator Capability

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

9.3.2 Provision should be made for adequate secondary instrumentation (e.g. temperature, pressure measurement) at locations where the parameters measured are representative of those at the meter.

9.3.3 The OGA 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.

9.4 Maintenance Frequencies

9.4.1 Initial recalibration intervals should be proposed at the PON6 stage, using a risk-based approach.

9.4.2 The potential use of diagnostic facilities should be strongly considered at the design phase.

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

9.5 Sampling

9.5.1 Operating conditions (pressure, temperature) at the separator are likely to differ – possibly substantially - from those at the export metering station. A commonly-adopted allocation methodology is to 'pro-rate' the outputs from one or more separators so that their sum agrees with the total exported from the installation. In such cases, knowledge of the compositions of the oil and gas at each separator is critical in order that the phase changes between separator and export metering may be modelled effectively; sampling is therefore an important part of the overall measurement and allocation strategy.

9.5.2 Sampling may also be required in order that the water-in-oil content may be determined.

9.5.3 Where samples are to be collected for analysis, the frequency of sampling shall be agreed with the OGA at the PON 6 stage, and may be reviewed from time to time thereafter.

9.6 Measurement Technologies

9.6.1 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.

9.6.2 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

9.6.3 The choice of meter technology for each outlet will be discussed and agreed with the OGA at the PON 6 stage.

(i) 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.

Operators should 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 should be made for the determination of liquid density. This may be based on direct measurement or on the off-line analysis of representative samples. In two-phase applications where the water content is determined via an off-line calculation based on wet-oil- and base-densities, the reference density must be kept up-to-date since this technique is highly sensitive to changes in base density.

Provision should 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 the OGA at the PON6 stage.

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.

(ii) 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 should be made for manual sampling at the gas outlet. The use of on-line densitometers may well be precluded by the possible presence of liquids. Gas composition is commonly determined by the off-line analysis of representative samples. However, the use of gas chromatographs may be appropriate in some cases, as the additional installation and operation costs may be more than offset by the reduction in overall measurement uncertainty.

(iii) Water Outlet Measurement

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

10. Test Separator Measurement for Allocation Purposes

10.1 Introduction

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

- Where the agreed Method of Measurement for the relevant field(s) is 'Flow Sampling', 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 based on multiphase metering, with the multiphase meter (MPFM) periodically verified against the test separator.

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

10.1.3 Flow meter performance during well testing may fall far short of the levels potentially achievable in single-phase laboratory applications. Nevertheless, these uncertainties may be minimised by the adoption of best practice.

10.2 Test Separator Design

10.2.1 In either of the two scenarios described above in paragraph 10.1.1, the test separator is unlikely to have been designed with fiscal service in mind. In order to minimise measurement uncertainty to an acceptable level, a significant upgrade of the test separator metering and/or instrumentation may be necessary.

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

10.2.3 The choice of meter for the gas and liquid phases should be considered carefully.

10.2.4 Sampling facilities should be provided to enable representative samples to be obtained.

10.3 'Flow Sampling' – Well Test Procedures

10.3.1 Where 'Flow Sampling' is the agreed method of measurement, an agreed frequency of well tests should be agreed with the OGA, and stated in the PON6.

10.3.2 The OGA will normally 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.

10.3.3 The relevant procedures should be made available for review by the OGA.

10.4 Multiphase Measurement – MPFM/Test Separator Comparison Procedures.

10.4.1 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 comparisonswill be agreed with the OGA and stated in the PON 6.

10.4.2 The Operator should prepare written procedures for the periodic comparisons. 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 acceptance criteria for considering any test to have been successful, with a documented investigation plan for when these criteria have not been met.

10.4.3 The relevant procedures should be made available for review by the OGA.

11. Multiphase Measurement in Allocation Applications

11.1.1 The use of multiphase flow meters (MPFMs) in allocation applications is now well established on the UKCS. The OGA and its predecessors have long accepted that their use in such applications is essential if the remaining reserves in the North Sea are to be exploited.

11.1.2 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 past two decades.

11.1.3 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 the OGA's expectations on Operators with this overall aim in mind.

11.2 Typical Applications of MPFMs

11.2.1 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 economically justified.

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

11.2.3 The table below indicates some of the typical configurations in which MPFMs have been used in fiscal applications in the UK sector of the North Sea.

Application	MPFM Verification Method	Comments
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.
MPFM subsea, measuring all wells from a single satellite field.	Comparison of MPFM with test separator. Relatively complex comparison in view of significantly different process conditions at MPFM/Test Separator, and in view of distance between these. Procedures must take account of possibility of slugging in flow line, etc.	Allocation to satellite field relatively straightforward. PVT data required periodically; frequency higher where individual well characteristics believed to be significantly different. However, in practice it may be difficult or impossible to update initial PVT data.
MPFM subsea, measuring all wells from more than one satellite field.	Comparison of MPFM with test separator. 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. PVT data required periodically; frequency likely to be higher than in the above case, since fluid characteristics likely to show greater variability. However, in practice it may again be difficult or impossible to update initial PVT data

11.3 Meter Selection

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

11.3.2 To facilitate meter selection, the Operator must establish the production profile and the range of pressures, temperatures and compositions that will be measured by the MPFM during its period in service. This should permit the vendor to determine the size and specific configuration of the meter.

11.3.3 The eventual 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.)

11.3.4 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.

11.3.5 It is recognised that the different multiphase measurement technologies are each better suited to some applications than 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.

11.3.6 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. 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.

11.4 Service and Maintenance Agreements

11.4.1 To a greater extent than for any other type of primary flow element used in oil and gas measurement, the successful operation of MPFMs requires the continued active participation of the meter manufacturer throughout the life of the field. Therefore, service and maintenance agreements should be set up at the outset. The possibility of remote monitoring by service engineers should be utilised wherever possible.

11.5 Onshore MPFM Calibration

11.5.1 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').

11.6 Onshore Calibration - Static Testing

11.6.1 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.

11.6.2 This may consist 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.

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

11.7 Onshore Calibration – Flow Loop Tests

11.7.1 Operators are strongly urged to arrange for dynamic (flow loop) tests to be carried out prior to agreeing to the use of a MPFM in an allocation 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.

11.7.2 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.

11.7.3 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.

11.8 System Integration Test

11.8.1 Before the MPFM and its associated secondary instrumentation is installed offshore, testing should take place to ensure the correct operation of the system as a whole (communication between devices, data hand-over, etc.). This is particularly important in subsea applications.

11.9 Offshore Calibration – Static Testing

11.9.1 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.

11.9.2 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.

11.10 Comparison of MPFM with Test Separator

11.10.1 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.

11.10.2 Whenever the Operator's reverification strategy depends on periodic comparison of the MPFM with the test separator, the OGA 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.

11.10.3 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.

11.11 Verification Techniques

11.11.1 Some MPFM models now feature diagnostic facilities which provide qualitative indications of meter performance.

11.11.2 With the agreement of all parties, these have the potential to allow the interval between successive meter verifications to be extended.

11.12 Sampling

11.12.1 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.
- Obtaining a compositionally-representative sample from a multiphase fluid at isothermal and isobaric conditions is likely to be one of the most challenging aspects of fiscal multiphase measurement. This is particularly true of subsea MPFM applications.

11.12.2 PVT information should be updated periodically. Operators should have in place a programme whereby certain key events (for example, the start of water-injection) 'trigger' a new programme of sampling.

12. Wet Gas Measurement in Allocation Applications

12.1.1 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 chapter of the Guidelines outlines the OGA's expectations on Operators with this overall aim in mind.

12.1.2 Where multiphase flow meters are used in 'wet gas' mode, the same considerations apply regarding meter selection, testing and calibration – Operators should consult Chapter 11 of these Guidelines for an indication of the OGA's expectations.

12.1.3 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.

12.1.4 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.

12.2 Differential Pressure Meters

12.2.1 When wet gas flow passes through a differential pressure (ΔP) 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.

12.2.2 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, over a limited range of meter parameters (e.g. meter size and β-ratio) and operating conditions.

12.2.3 Recent work by industry has highlighted the fact that despite the 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.

12.2.4 In general, differential pressure meters in wet gas applications behave more like their single-phase equivalents as pressure is increased.

12.2.5 The use of meter, and the correlation to be used, should be discussed with the OGA at the PON 6 stage.

12.3 Determination of Gas and Liquid Density

12.3.1 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.

12.3.2 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.

12.4 Determination of Liquid Content

12.4.1 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, it may be possible to determine the liquid content from the analysis of representative samples (as described above). An estimate of liquid content can potentially be obtained when it is possible to route the flow through a test separator.

12.4.2 In wet gas applications the pressure loss across a Venturi is generally much greater than in analogous dry gas situations. Methods have been developed to determine the liquid loading as a function of the pressure loss across the Venturi. This has the potential to eliminate the need for a separate technique to determine water content.

12.4.3 The proposed method to determine liquid content should be discussed with the OGA at the PON 6 stage.

12.5 Comparison of Wet Gas Meter with Test Separator

12.5.1 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 it provides an opportunity to verify the performance of the wet gas meter.

12.5.2 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.

13. Well Flow Rate Determination for Reservoir Management

13.1.1 As part of the OGA's wider Stewardship process (See Reference [1] at end), the OGA's Metering Team may periodically review Operators' strategies and procedures for well testing.

13.1.2 The flow rate of each of the three phases (oil, gas and water) produced by a well is typically determined by periodic 'well testing', whereby flow from the well is diverted either to:

(i) a test separator, equipped with single-phase meters on each of the outlets, or (more rarely)

(ii) a multi-phase flow meter (MPFM).

These single-phase flow rates are typically used as input to reservoir models.

Unfortunately, the well testing process is subject to a relatively high level of uncertainties and systematic measurement errors may be expected to occur.

13.2 Factors Affecting Well-Test Results

(i) Single-phase measurements

13.2.1 The nominally single-phase measurements of oil, gas and water on the outlets of a test separator are likely to be subject to installation effects, leading to measurement bias.

13.2.2 The calibrations conditions of the single-phase meters (assuming they have been calibrated at all) are unlikely to be representative of those experienced by the meters in service. Space and residence-time constraints may result in non-ideal flow profiles at the meters. Flow through the meters may be only nominally single-phase; gas breakout at the oil meter and the presence of liquids in the gas meter are likely in many typical test separator applications.

13.2.3 In practice, Operators have typically been more concerned with the repeatability of the meters used in well-test systems – and in the ability to detect trends – rather than in the uncertainty of the single-phase measurements.

13.2.4 Recent work has suggested that even well-maintained and well-operated separators will have uncertainties in the range of 2-4% on liquid (water and oil, separately), and 2-5% on gas. Where conditions are less than ideal, errors above 5% on liquid, and 10-15% on gas, are often encountered. [2]

(ii) 'Reconciliation' of well test results

13.2.5 In most cases, single-phase measurements of the commingled production from all of the wells in the field takes place at a lower uncertainty downstream of the test separator. Production from each individual well is 'pro-rated', so that the sum of production of each phase from each well matches that produced from the reservoir as a whole. In practice, reconciliation factors tend to be systematically below 1 (and in the range 0.85-0.90). [2]

13.2.6 In pro-rating volume production rates from each phase for each well, transfer between the phases must be considered. Thus, if the operating pressure is lower at the point where the commingled production is measured than it was at the test separator, transfer from the liquid to the gaseous phase may take place. This process may be modelled, but the modelling process (which is itself inherently uncertain) depends on knowledge of the physical properties of the hydrocarbons produced by the well; this is determined by laboratory analysis of samples obtained during the well test.

13.2.7 The effect of the reconciliation exercise is that well test results are given an inherent bias. The scale of the bias depends on the magnitude of the reconciliation factor; the absolute effect on an individual well is proportional to the share of that well's production to that of the reservoir as a whole.

(iii) Well test frequency

13.2.8 In general, there is no regulatory requirement from the OGA to test individual wells at any given frequency. The only exception to this is when well-testing forms the basis of the method of measurement for the field as a whole, as agreed at the PON 6 stage; then the OGA typically expects wells to be tested at monthly intervals.

13.2.9 For reservoir modelling purposes, flow rates between well tests are estimated by interpolation, using an assumed decline curve. In general, the greater the time between successive well tests, the higher the uncertainty inherent in this process.

13.2.10 In general, higher-producing wells should be tested at greater frequencies.

(iv) Well test duration

13.2.11 It may be difficult to obtain representative conditions during well tests. This is particularly true in the case of wells tied back to a platform over long distances, when unstable flow and/or slugging may be anticipated.

13.2.12 The demands of well testing – for example, the time taken to obtain stable conditions – must always be balanced against wider operational requirements, and often, the duration of well tests will be curtailed as a result.

13.2.13 As a consequence, well tests may take place during periods of unstable flow (with resultant measurement error), or the results may be unrepresentative.

(v) Test separator availability

13.2.14 Where a test separator is not available (for example, when the separator has been dedicated to use as a production separator for a satellite field), or where production from an individual well or group of wells cannot be diverted to the test separator, it may be possible to adopt the strategy of ‘well testing by difference’. However, while it is possible to minimise the associated uncertainties [3], such an approach inevitably results in less reliable data than direct well testing. It also relies on deferment of production from the well under ‘test’.

13.3 Effect of Bias and/or Uncertainty in Well-Test Results

13.3.1 Data used in reservoir simulation models are adjusted so that the output from the simulation matches observed flow rates, in a process known as ‘history matching’. Where these observed flow rates are in error, the history matching process - and by extension the reservoir simulation as a whole - is compromised.

13.3.2 Recent modelling work performed for the OGA has determined the effect of bias in well test results on the determination of Recovery Factor (RF) for a typical North Sea reservoir. For the reservoir modelled, the error in RF for a -10% bias in oil flow rate was ~-15%; for a +10% bias the error in RF was ~+4%. Thus, negative errors have a proportionately larger effect.

13.3.3 The use of incorrect Recovery Factor has many consequences, some of them serious:

- The ultimate recovery from a reservoir may be adversely impacted.
- Business decisions (such as the location of infill wells) that are based on reservoir modelling may be based on information that is insufficiently robust.
- The calculation of Production Efficiency – a key metric for Industry and the OGA alike - may be compromised, as a result of the incorrect determination of well potentials.
- Anticipated production figures are likely to be in error; this will impact on business planning decisions (not to mention applications for Production and Flare Consents from the OGA).

13.4 OGA Review of Well Testing

13.4.1 The OGA may from time to time review Operators' well-test strategies and procedures for individual assets.

13.4.2 Considering each of the 'factors affecting well tests', as listed above, in turn:

(i) The degree of reliability of the single-phase measurements can be determined relatively easily by considering factors such as calibration and maintenance histories, Piping and Instrumentation Diagrams of the test separator and associated pipework.

(ii) The magnitude of the reconciliation factor for each phase (as well as that for total mass) provides perhaps the single most valuable metric for assessing the reliability of the well test regime as a whole. The further the factor is from 1, the greater the overall uncertainty and potential for significant hidden bias.

(iii) Historic well test frequencies may be reviewed.

(iv) The planned and actual duration of well tests, and the associated procedures (including sampling) may be reviewed. Taken together with (iii) above, this may be used to inform the OGA's opinion regarding the degree of robustness of the well-test strategy as a whole.

(v) Well testing 'by difference' determines a nominal flow rate from each well. When all wells are flowing together, the sum of these nominal flow rates will differ from the measured, combined, flow.

(vi) The degree to which these two figures differ provides an indication of the robustness of the 'by difference' method.

13.4.3 The OGA may exceptionally require Operators of higher-producing fields to carry out uncertainty calculations on their well-test systems. The quantitative figures resulting from such studies would provide qualitative indicators on the reliability of metrics such as recovery factor, production efficiency calculations or production consent calculations, based on the degree of confidence in the well-test - and by extension, reservoir modelling – regimes as a whole.

13.4.4 Where intermittent well flow rate determination is clearly unsatisfactory, the OGA may recommend the use of non-intrusive ('clamp-on') technologies to provide continuous flow rate measurement.

13.5 References/Notes

[1] **OGA Stewardship Expectation No. 6 (SE06) – Integrated Field Management**[12]

[2] **Pinguet, B.**
"A way forward to comparison of MPFM tests from flow-loop to field conditions."
SE Asia Flow Measurement Conference, 2017

[3] **Zimmerman, M.; Haldipur, P.; Sheridan, M.**
"Managing By-Difference Well Testing Challenges in a Dynamic Subsea Flow Production Environment."
Upstream Production Management 2015.

[12] https://www.ogauthority.co.uk/media/5900/oga_se6_integrated_fields_july_2019.pdf