Main Index

NSFMW.97

North Sea FLOW Measurement Workshop

Paper ~~7~~: 2.1

REVISED DTI GUIDELINES FOR PETROLEUM MEASUREMENT

Authors:
D. Griffin, L.N. Philip,
DTI Oil & Gas Office, Aberdeen, UK

Organiser:
Norwegian Society of Chartered Engineers
Norwegian Society for Oil and Gas Measurement
Co-organiser:
National Engineering Laboratory, UK

NORTH SEA FLOW MEASUREMENT WORKSHOP 1997

Revised DTI Guidelines for Petroleum Measurement

D Griffin, L Philp, DTI Oil & Gas Office, Aberdeen

Introduction

The DTI's guidelines on petroleum measurement have been extensively revised and enlarged. The new guidelines cover a much wider scope of measurement situations than before. Included in the new issue is guidance on allocation measurement, well testing, multiphase flow measurement, new technology acceptance procedures and operating procedures for different types of measurement systems.

Significant changes have taken place in recent years both in the way the oil and gas industry conducts its business and in the fiscal regime operated by the UK government. New developments in flow measurement have progressed to such an extent that they have now been adopted by the industry or are close to being adopted as beneficial methods of the measurement of hydrocarbons in whatever form they present themselves for measurement.

The rapid pace of development has left the standards-making bodies behind and in some cases there is insufficient quality data to enable the standards makers to produce guidance of the generic type appropriate for national or international standards.

The case-by-case approach of the DTI in approving methods of measurement lends itself better to consideration of new technology where there may be no existing standards.

These, amongst other considerations, make it appropriate for the DTI to extend the scope of its guidance into these new areas.

The policy developments behind the changes in the new guidelines are not static and this new document has been produced in response to an evolutionary process which is still continuing but it is right to collate and make defining statements from time to time to put on record the current status of measurement requirements for the purpose of attaining DTI approval.

The main changes in the new approach are:-

1. Earlier contact and bringing together of Annex B and detailed engineering design appraisal into a continuous "one stop shop" procedure.

2. Early agreement on purpose and category of measurement with attendant benefits in reducing the amount of work involved in the option screening process.

3. Uncertainty objectives set for each category of measurement system.

4. Options to consider "health-checking" methods rather than elapsed time for periodic verification of system component performance.

In this paper I do not intend to go through the new document clause by clause (you will be pleased to hear) but try to give a flavour of the new guidelines and what we are trying to achieve. A full copy of the new guidelines is appended to the paper so you will all be able to conduct your own review.

In that context I intend that there will be a permanently open file in my office so that any comments, observations or suggestions for improvement can be sent to us at any time. I don't know when the next revision will be issued but the value of having a file of user comments is to help shorten the consultation process at each revision. A contact address is included in the new guidelines.

The Guidelines

In contrast to the previous guidelines [1-3], the new issue is a self-contained document dealing with all aspects of petroleum measurement (liquid, gas and multiphase) as well as operating procedures.

The document is split into 5 main parts:

1. General
2. Liquid Petroleum
3. Gaseous Petroleum
4. Muliphase Petroleum
5. Operating Procedures

Part One, General is a new addition to the previously issued guidance and outlines the area of application of the guidelines, briefly describes the underling regulatory framework, puts into context the purposes for which measurement is required, establishes broad categories of measurement systems, and indicates the documentation required for our review, the reference standard documents of most relevance and their value as underpinning guidance.

Part Two updates the existing liquid document and adds new sections dealing with allocation metering and the use of test separators for reservoir management. Included in this part is guidance for offshore loading fields not attracting field specific taxes.

Part Three broadly parallels the liquid part but is concerned with gaseous petroleum measurement.

Part Four briefly addresses the subject of multi-phase measurement. This is a short part not because there in little to say about multi-phase metering. On the contrary, much new information and data is being produced and digested but a consensus has not yet emerged on how best to write standards or even codes of practice. In the UK and elsewhere evaluation of the technology is proceeding apace. The case by case approach which we use in conventional metering systems is adopted with modifications when considering the use of new technology. I would like to add that the papers and discussions which are such a prominent feature of the NSFMW are the main source of data and information which inform the deliberations of the standards makers. Clearly views on the deployment and use of multi-phase meters are developing along with the maturing of the technology. Our guidance will likewise evolve.

Part Five covers operating procedures for the three process types, liquid, gas, and multi-phase.

As before the guidance contained in the document is intended as representing general minimum requirements for each "class" of metering considered.

The guidance is not intended to stifle innovation and alternative specifications will be considered provided that they can be shown not to result in any diminution of the reliability and accuracy of the measurement. Should a Licensee wish to incorporate novel elements in the design of either

- a proposed new metering station, or
- an existing metering station

the Department may require that the Licensee establish an evaluation programme. The Department may wish to be involved in its design and implementation and in the evaluation of the findings of any such programme.

One of the most important features of the new Guidelines is the introduction of the concept of "Measurement Category". Rather than apply a blanket requirement for "fiscal-quality" metering, The DTI Oil & Gas Office (OGO) now determines the measurement requirements for each field on a case-by-case basis. Among other things, OGO takes account of:

- the fiscal regime in which the field itself lies - does it attract Petroleum Revenue Tax (PRT) or Royalty?
-
- the evacuation route of the metered petroleum - does it form part of an allocation system with PRT/Royalty-paying petroleum?
-
- the petroleum production rate of the field
-
- the field economics

The time allocated to this presentation is quite short and in many ways the new guidance document speaks for itself, so I will conclude by commending the new guidance document as a first attempt tocover the more general aspects of petroleum measurement rather than the previously narrower perspective in the UK of full "fiscal" quality metering. I am happy to answer any questions you may have about the content of the document or the policy changes behind the new approach.

References

[1] DTI Metering Standards for Liquid Petroleum Measurement, Issue 4a, Aberdeen 1994

[2] DTI Metering Standards for Gaseous Petroleum Measurement, Issue 4a, Aberdeen 1994

[3] DTI Approved Metering Stations - Operating Procedures (Liquid Hydrocarbon Measurement), Issue 4a, Aberdeen 1994

Appendix 1

Insert
New guidelines Issue 5

Department of Trade and Industry

dti

Oil and Gas Office

GUIDANCE NOTES FOR

STANDARDS FOR PETROLEUM MEASUREMENT

Under the Petroleum (Production) Regulations

SEPTEMBER 1997

ISSUE 5

This page is intentionally left blank.

CONTENTS

PART THREE

Gaseous Petroleum

3.1 "Fiscal quality" measurement *(revision of existing document).*

3.2 Allocation, dry gas measurement.

3.3 Allocation, wet gas measurement.

3.4 Utility and fuel gas.

3.5 Flare or Vent Gas Measurement.

3.6 Test separator for reservoir management.

PART FOUR

Multiphase Petroleum

4.1 Allocation.

4.2 Well testing.

PART FIVE

Operating Procedures

5.1 Liquid measurement systems *(revision of existing document).*

5.2 Gaseous measurement systems.

5.3 Multiphase measurement systems.

APPENDICES

Appendix 1 Addresses and contacts.

Appendix 2. Measurement Model Clause.

Appendix 3. Reference Standards.

Appendix 4. Uncertainty Calculations.

PART ONE

General

1.1 Introduction

1.1.1 This document contains guidelines for Licensees and Operators in Great Britain, the territorial waters of the United Kingdom and on the United Kingdom Continental Shelf, for use in the design, construction and operation of metering systems for which the Secretary of State for Trade and Industry's approval is required under the model clause relating to the measurement of petroleum which is incorporated into licences issued under section 2 of the petroleum (Production) Act 1934 and which is reproduced in Appendix 2 (in these guidance notes referred to as "the measurement model clause").

1.1.2 The guidance on "fiscal quality" metering systems is a revision of documents already issued. However the Department recognises that there have been significant changes in recent years both in the fiscal regime and regulatory climate as well as in the way the industry conducts its business. In recognition of these changes this document contains guidance on other categories of measurement systems.

1.1.3 It is intended that the guidance contained in this document should be interpreted as representing general minimum requirements, and relaxation will only be considered in special circumstances. This guidance should not be viewed as prescriptive and alternative specifications to those given in this document will be considered provided that they can be shown to give a similar or greater level of fidelity, accuracy and reliability. It is not intended that adherence to this guidance inhibit innovation, but if a Licensee wishes to use new technology or to deploy existing technology in a novel setting then it will be necessary for the Licensee to provide full justification for his choice. In any case where new technology is proposed the Department may require that the Licensee establish an evaluation programme. The Department will wish to be involved in the design, implementation and evaluation of the findings of any such programme, and may call for independent experts to assist it in this.

1.1.4. In order to assist the Licensee in determining the purpose and selecting a measurement category he should contact the DTI Oil and Gas Office (OGO) at an early stage in the consideration of the development (pre Field Development Plan). Early consideration of measurement requirements will enable the Licensee to complete the screening of options an earlier stage and so minimise the effort in system evaluation. This procedure is intended to avoid the pitfall of the Licensee proceeding with a system design which is unacceptable to the OGO.

1.1.5. The OGO is committed to reviewing the way existing regulations are administered and in the spirit of deregulation will seek to lessen the regulatory burden on industry where appropriate. Taking this and CRINE into account there have been a number of relaxations both in levels of accuracy required from a metering system and in the recertification requirements. These new measures are particularly significant where a field pays neither Royalty nor Petroleum Revenue Tax (PRT) and does not impact on fields which do. The details of these relaxations are given in the relevant sections of this guidance.

1.1.6. Organisation charts for the DTI, Oil & Gas Division and Branch 3, Oil and Gas Office, Aberdeen together with contact addresses and telephone numbers are given in Appendix 1.

1.2 Regulatory Framework

1.2.1. The principle legislation which applies to the oil and gas production industry particularly in relation to petroleum measurement is as follows.

The Petroleum (Production) Act 1934.

The Act vests ownership of the petroleum which exists in its natural condition in strata in Great Britain and beneath the territorial waters of the United Kingdom in the Crown and gives the Secretary of State, on behalf of the Crown, the exclusive right to grant licences to search and bore for and get petroleum. The Act also authorises the Secretary of State to make regulations which, inter alia, prescribe the model clauses for incorporation into such licences.

The Continental Shelf Act 1964

The Act extends the powers conferred by the 1934 Act to the United Kingdom Continental Shelf.

The Petroleum Act 1987

Sections 17 and 18 and Schedules 1 and 2 to this Act amend the measurement model clauses which were incorporated into licences in force at the time it was enacted.

1.2.2. Petroleum measurement is implied by obligations in the licence in addition to those contained in the measurement model clause. This is discussed in paragraph 1.3.3 below.

1.2.3. Where petroleum is delivered to the UK via a pipeline which serves as a common transportation route for a number of fields then the "method of measurement" will include the measurement of petroleum at the terminal serving the relevant pipeline and the allocation procedures used to determine each contributing field's share of the petroleum used at or exported from the terminal.

1.2.4 In order to satisfy the Secretary of State that no unauthorised alterations to the approved method of measurement have been made, officers from the OGO may at their discretion inspect metering systems at any stage from construction through commissioning into production. Throughout the producing life of a field operators may expect that fields liable to pay Royalty or PRT or being co-produced or transported with such fields will routinely be inspected by officers of the OGO on an annual basis. Additional non-routine inspections may be required if circumstances warrant. Fields with no impact on Royalty or Petroleum Revenue Tax (PRT) are liable to be inspected on commissioning and thereafter at the discretion of the OGO on a less frequent basis than Royalty or PRT sensitive fields.

1.3 Purpose for which Measurement is Required

1.3.1 The first task in determining the suitability of a proposed measurement system or systems is to identify the purposes for which measurement is required;

a) where measurements are to account for petroleum won and saved from the licensed area;

b) for other purposes relevant to the licence.

1.3.2 Amongst the most usual purposes under (a) are;

i) To safeguard revenues from Royalty and PRT paying fields.

ii) To allocate terminal out-turns to contributing fields in shared transportation systems.

iii) To account for production of petroleum won and saved from stand alone fields not subject to Royalty or PRT.

iv) To account for petroleum in the form of crude oil, gas or LPG exported from terminals or other export facilities.

v) To allocate production into shared transportation systems from different fields commingled in shared process equipment.

vi) Fuel gas, utilities use and flare gas measurement.

1.3.3 And under (b);

i) To improve understanding of reservoir behaviour to enable effective reservoir management strategies to be implemented.

ii) To establish viability of reservoir as production prospect as for example with extended well tests (EWT).

iii) Flare gas measurement, fuel gas and utilities use.

iv) To account for gas or condensate re-injected into a reservoir for pressure maintenance or conservation.

v) To establish clearly whether a reservoir is no longer economically viable prior to initiating abandonment procedures.

1.4 Categories of Measurement Systems

1.4.1 In this section a number of categories of measurement systems are described along with indications of the accuracy levels to be expected in each of the categories. The list is not intended to be exhaustive or prescriptive but to indicate the broad area of operation of each category associated with a particular purpose. Within each category of measurement there will be scope to vary the detailed method of achieving the measurement objective. The categorisation of a system is agreed between the Licensee and the OGO at the early discussion stage.

"Fiscal quality" measurement

1.4.2 This quality of measurement by industry consensus is ±0.25% uncertainty for liquid (i.e. oil, LPG, condensate) and ±1.0% for gas. These are overall uncertainties and are derived from an appropriate statistical combination of the component uncertainties in the measurement system. The equipment used to achieve this level of performance will vary according to the particular circumstances of each development. The deployment of new technology in this area, while superficially attractive, carries with it in the early phases of its use, the additional problem of establishing confidence in the equipment and the suitability of the recertification procedures.

"Allocation" Metering.

1.4.3 This quality of measurement is usually taken to mean measurement by which a quantity of product which has been metered to a higher standard is attributed to different sources. The quality of measurement needed will depend on whether the contributing sources are in the same fiscal regime, have the same equity, or in some way influence the measurement of production from fields sharing the same processing or transportation infrastructure. In some cases "fiscal quality" measurement may be the appropriate standard for field allocation. In the case of liquids from fields with differing fiscal status where "fiscal quality" metering is not technically or economically feasible then **continuous** measurement to an uncertainty of ±0.5% to 1.0% would be required and in the case of gaseous petroleum 2.0% to 3.0%, provided that the overall larger uncertainties do not mask significant systematic errors which would introduce bias in the production accounting.

"Allocation" measurement by intermittent methods; "Flow Sampling".

1.4.4 The use of a test separator to allocate field production to individual wells is a long-established method for the purpose of optimising well performance and managing reservoir operations. Industry tends to use the term "allocation by well test" when this method is used to allocate commingled production between contributing fields rather than wells in the same field. To permit the use of a test separator for field allocation it would normally be necessary to enhance the test separator metering capability both in terms of the instrumentation used and in the operating procedures. It is preferred to use the term "Allocation By Flow Sampling" to distinguish between the procedures used for "field allocation" and reservoir management. Target uncertainties for allocation by flow sampling should be of the order of ±5%.

The use of test separators for reservoir management.

1.4.5 This is a well-established method and the expected levels of uncertainty are 5% to 10%. If it is proposed to use the new technology of multiphase metering it would be expected to perform as well as or better than the traditional test separator method. There are at present six or seven leading contenders in the field of multiphase metering but as yet no single instrument can meter the full range of flow patterns and oil/gas/water mixes in every possible combination of concentrations from 0 to 100%. The manufacturers make claims for their instruments which are difficult to verify independently but various claims are made purporting to show equivalent performance to that of test separators. The technology is still at an early stage in its development and there are prospects for significant improvements. A significant problem with the new technology is that the rate of development is so rapid that the various standards bodies both national and international are unable to produce standards or codes of practice on a time scale that would permit early deployment. While the prospects appear good at present for the rapid improvement of this technology to the stage where it will achieve wider acceptance by the industry a watching brief will be kept on the developing situation with a view to issuing an updating addendum in about eighteen months.

Stand-alone Fields loading offshore. (Fields which do not share production or transportation facilities with other fields)

1.4.6 Provided satisfactory procedures can be developed for initial and periodic verification liquid ultrasonic meters may offer a satisfactory solution to the cost effective metering in these circumstances. The target uncertainty for this method would be 0.5% to 1.0%.

Fuel Gas and Utilities

1.4.7 For fuel gas and utilities use the measurement is usually categorised as normal process quality measurement. The measurement uncertainty expected for this class of measurement is 2.0% to 4.0%.

Summary

1.4.8 This approach introduces an element of prescription which has hitherto not been DTI policy. The aim has been to operate the "good oilfield practice" requirement in the regulations on a case by case basis. However by agreeing the purpose for which the measurement is required and assigning a measurement category and target uncertainty at the Annex B stage, the somewhat adversarial approach of earlier years should be eliminated. This will result in the Licensee being able to concentrate on a design that will meet the agreed objective rather than preparing economic and technical arguments to persuade the Department to agree a method which falls short of what is normally described as "full fiscal quality". Although the introduction of an element of prescription into the review process appears at first sight to run contrary to the spirit of deregulation, in practice it should result, through the change in administrative procedure, in a reduction of the regulatory burden on operators.

1.5 Reference Standard Documents

1.5.1 Reference standards commonly used in the oil and gas industry for petroleum measurement are listed in Appendix 3. The standards listed deal by their very nature with established methods and technology and offer no guidance as to best practice in the deployment of new and emerging technologies in the field of fluid flow measurement and allied topics. In relation to published standards in flow measurement it is not intended that Licensees should adhere slavishly to the detailed provisions of the standards but rather to use the standards to guide and inform their discussions with the OGO in arriving at a consensus view as to what constitutes "good oilfield practice" in the specific context of the proposed development.

1.5.2 If a Licensee proposes to deploy a new technology in his proposed method of measurement for which no recognised standards exist then it will be necessary for the Licensee to provide a detailed justification for his choice. This justification may involve the establishment of a programme of tests to evaluate the performance of the chosen equipment. The objectives, design, methodology and acceptance criteria of any evaluation programme should be agreed in advance with the OGO. The OGO should be given the opportunity to witness tests at its discretion. Such evaluation programmes may also be necessary where it is intended to deploy existing technology in a novel setting. The Licensee should consider the inclusion of independent experts in any evaluation programme.

1.6 Documentation Requirements

1.6.1. The Department of Trade and Industry Petroleum Operations Notice (PON) No. 6 contains details of the documentation needed for the OGO to conduct its review of the method of measurement. It is reprinted in Appendix 2.

1.6.2 The production reporting requirements are the subject of a separate operating notice, PON No. 7. This is also reprinted in Appendix 2.

PART TWO

Liquid Petroleum including Crude, LPG, Gas Condensate.

2.1 Fiscal Quality

Mode of Measurement

2.1.1 Hydrocarbon measurements for requirements under the measurement model clause should be either in volumetric or mass units. The choice of measurement should be discussed with the OGO. Volumes should be measured in cubic metres and mass in tonnes (in vacuo). Volume will normally be used for stand-alone field tanker loading operations and mass for multifield pipeline or offshore pipeline with an allocation requirement. The overall level of uncertainty required is ±0.25%.

2.1.2 Where the approved measurement is in volumes, these should be referred to standard reference conditions of 15°C temperature and 1.01325 bar pressure. The metering system should compute referred volumes by means of individual meter temperature compensation and totalisers. Pressure compensation will always be required whether continuously or by a fixed factor determined at each proving as appropriate. Alternative systems giving equivalent results can be considered.

2.1.3 Where the approved measurement is in mass units the established method is by measuring the volume and density. The density should if necessary be compensated to the volume meter inlet conditions and the mass computed as the product of this density and the measured volume, $V_{mi} \times \rho_{mi}$, where Vand ρ_{mi} are volume and density respectively, measured at meter inlet conditions of pressure and temperature. When mass is not $V_{mi} \times \rho_{mi}$ then any factors used in computing metered mass (Q_m) at some other set of conditions should cancel with respect to volume meter inlet conditions. This procedure is unnecessary if mass is measured directly by Coriolis meter.

Meters and Associated Pipework

2.1.4 The meter should generate the electrical signal directly from the movement of the meter internals without any intermediate gearing or mechanical parts. Electronic interpolation systems may be accepted. Although the meters traditionally used for this service are either turbine or positive displacement meters new types are available which if properly installed and operated can deliver similar levels of performance. The main new contender for this category of measurement is the Coriolis meter, but with ongoing developments in the field of petroleum measurement other technologies may be able to perform at the fiscal quality level.

2.1.5 A sufficient number of parallel meter streams should be provided to ensure that, at the nominal maximum design production rate, at least one stand-by meter is available, to maintain a high level of availability. Adequate valving should be provided such that individual meters may be removed from service without shutting down the entire metering system.

2.1.6 Metering stations should have a common inlet header and, if necessary, a common outlet header to ensure uniform measuring conditions at all metering streams, temperature and pressure transducers and density meters. However if product of differing physical properties is produced by separate production trains and is not fully commingled before metering then it may be necessary to have separate measurement of the differing fluids.

Secondary Measurements

2.1.7 Temperature and pressure measuring points should be representative of conditions at the meter inlet and situated as follows:-

(a) In volumetric measurement systems: as close as to the meter as possible without infringing the requirements of the API Measurement Manual.

(b) In mass measurement systems: an additional set of measurements may be required as close to the densitometers as possible.

2.1.8 Temperature measurements that affect the accuracy of the metering system should have an overall loop accuracy of at least 0.5°C, and the corresponding readout should have a resolution of at least 0.2°C. This is equivalent to an uncertainty of approximately 0.05% in CTL. Thermowells should be provided adjacent to the temperature transmitters to allow temperature checks by means of certified thermometers.

2.1.9 Pressure measurements that affect the accuracy of the metering system should have an overall loop accuracy of at least 0.5 bar and the corresponding readout should have a resolution of at least 0.1 bar.

2.1.10 Dual density meters should normally be used and should feature a density discrepancy alarm system. Single density meter systems, where they have been allowed should feature high and low set point alarms. Suitable sampling facilities shall be provided in close proximity to the density meter(s) in all cases. Provision should be made for solvent flushing on systems where wax deposition may be a problem. Densitometers should be installed as close to the volume flow meters as possible and be provided with thermowells and pressure indicators so that it may be demonstrated that there is no significant difference from the volume flow meters' inlet conditions. If this is not the case, temperature and pressure compensation must be applied. If the densitometers are in a recirculation loop then the inlet probe should be a correctly designed sample take-off probe and positioned to extract a flow of representative composition.

Prover Loops and Sphere Detectors

2.1.11 Preferably prover loops should be of the bi-directional type to eliminate possible directional bias. They should have a suitable lining. The flanged joints within the calibrated volume should have metal to metal contact and there should be continuity within the bore. Connections should be provided on the prover loop to facilitate recalibration with suitable calibration equipment which may be a dedicated water draw tank, portable calibration prover loop and transfer meter, or small volume type prover, where this is approved by the OGO for use in the particular application using the in-service liquid as the transfer medium, or other suitable liquid if approved by the OGO.

2.1.12 Provers should be constructed according to the following criteria:-

i. Number of meter pulses generated over swept volume to be 20,000 pulses. (This is equivalent to 10,000 pulses between detectors on bi-directional provers.)

ii. Resolution of detector/displacer system to be compatible with requirement (i).

iii. Displacer velocity not to exceed 3m/s to avoid slippage past the displacer but may be faster with piston type provers if seal integrity can be demonstrated.

Because the resolution of the detector/displacer system can only be gauged by the actual performance of the prover, the Department expects the manufacturer to demonstrate an acceptable repeatability during calibration of the prover, such that on 5 consecutive round trips the range of volumes does not exceed ±0.01% of the mean volume. Alternatively, a statistically equivalent repeatability criterion for small volume provers or meter pulse gating systems may be used.

2.1.13 For offshore use, or in remote locations, prover loops should be fitted with dual sphere detectors and switches at each end of the swept volume. At least two volumes should be calibrated so that failure of a detector or switch does not invalidate the prover calibration. The detector should be designed such that the contacting head of the detector protrudes far enough into the prover pipe to ensure switching takes place at all flow rates met with during calibration and normal operation. Detectors and switches should be adequately waterproofed against a corrosive marine environment.

2.1.14 In the case of mechanical switches, each sphere detector should have a dedicated micro-switch. The actuation of each detector unit should be set during manufacture so that should it be necessary to replace a detector unit during service there will be a minimal change in prover calibrated volume.

NOTE: Other designs of prover may be considered subject to their being in accord with good oilfield practice.

Recirculation Facilities

2.1.15 The Department does not normally permit the fitting of recirculation loops to metering systems except in production systems featuring rapid tanker-loading. Where recirculation systems are fitted around the metering system, full logging of recirculation and any other non-export flows through the meters must be maintained. Any such system must be properly operated and maintained.

2.1.16 Recirculation facilities intended for the use of pump testing etc. should be fitted upstream of the metering system.

Pulse Transmission (PD and Turbine Meters)

2.1.17 The metering signals (see also section 5.1) should be generated by a dual meter head pick-up system in accordance with either Level A or Level B of the IP 252/76 Code of Practice. This is to indicate if signals are "good" or to warn of incipient failure of meter or pulse transmission.

2.1.18 A pulse comparator should be installed which signals an alarm when a pre-set number of error pulses occurs on either of the transmission lines in accordance with the above code. The pre-set alarm level should be adjustable, and when an alarm occurs it should be recorded on a non-resettable comparator register. Where the pulse error alarm is determined by an error rate, the error threshold shall be less than 1 count in 10^6. Pulse discrepancies that occur during the low flow rates experienced during meter starting and stopping should be inhibited. This is to avoid the initiation of alarms for routine process situations thereby tending to induce a casual attitude to alarms in general.

2.1.19 The pulse transmission to the prover counter should be from one or both of the secured lines to the pulse comparator, and precautions should be taken to avoid any signal interference in the spur from the comparator line. This is to ensure that meter factors are determined with as good pulses as are used to totalise production.

Totalisers and Compensators

2.1.20 All totalising and compensating functions, other than data input conversions, should be by digital methods, to establish a high level of confidence in the accuracy of the system.

2.1.21 Each meter run should have an instrument computing uncorrected volumes at line conditions in which meter factors should be capable of being set to a resolution of at least 0.03% of value. In volumetric measuring systems, a liquid pressure correction may be included in the computation as this correction is usually small and of constant magnitude. Where a metering skid operates over a wide range of pressures as a routine then continuous correction for pressure effects may be appropriate.

2.1.22 Totalisers on individual meter run instruments, and on station summators, should have sufficient digits to prevent roll-over more frequently than every 2 months and normally have a resolution of 1 unit of volume or mass. Totalisers should be non-resettable and, where they are of the non-mechanical type, should be provided with battery driven back-up memories.

The procedures to be used for correcting flow during any period of mismeasurement should be made available.

2.1.23 For the volumetric mode of measurement, automatic temperature compensation is required. Temperature compensation should be carried out on each individual meter stream. The liquid thermal expansion coefficient should be fully adjustable over the range likely to be encountered in practice and have a resolution of at least 1%.

2.1.24 Corrections to meter throughput for water and sediment content should be applied retrospectively based on the analysis of the flow-proportional sample. However it is recognised that the new generation of water-in-oil meters is approaching levels of performance associated with traditional methods and is likely to become acceptable within the currency of this document. Any application to use new methods will be reviewed on a case by case basis according to the policy for adopting new technology.

Other Instrumentation

2.1.25 To provide a history of meter operation and flowing conditions and a record of meter malfunctions, each meter-run should be provided with a continuous chart recording of flow rate and metering temperature. Alternatively, electronic data recording will be accepted provided that the recording frequency is adequate and the system logs all metering alarms. Recording intervals no greater than 4 hours will normally be considered adequate.

2.1.26 In mass measurement systems, the density signals from the density meters should also be recorded continuously by a chart recorder or electronic data recorder at the same interval as in 2.1.25 above. A digital read-out is also required with a resolution of at least 4 significant figures.

2.1.27 Crude oil metering systems should be provided with automatic flow proportional sampling systems for the determination of average water content, average density and for analysis purposes. It is important to ensure that properly designed sample probes are used and positioned in such a way as to ensure representative sampling. Sample extraction rates should be "isokinetic" according to ISO 3171. These samples are required to account for dry oil quantities and allocated quantity determination. They may also be used for valuation purposes. In special circumstances when flows are specifically held constant (e.g. well testing) spot or time based sampling may be acceptable. The use of on-line water-in-oil monitors will be dealt with in accordance with the new technology procedures.

2.1.28 In crude oil systems where slugs of water may occur, in line water detection probes should be fitted to detect abnormal levels of water content. Continuous recordings of percentage water content and a high-level alarm system should be provided. Data from this source should not normally be used in determining dry oil quantities. This may only be used as a back-up in case of failure of agreed sampling and analysis procedures.

Security

2.1.29 In order to show if accidental or malicious interference with these critical components has occurred, all meter factor settings and reset buttons, where allowed, should be secured with a seal, lock or password to prevent unauthorised adjustment. Prover loop sphere detectors and associated micro-switches should also be secured by locks or seals.

2.1.30 Valves on re-circulation lines, provided for the purposes of off-line meter testing via re-circulation loops, must be provided with approved type locks.

Calibration Facilities

2.1.31 Adequate test facilities should be provided with metering systems to facilitate the checking and calibration of all computing and totalising systems. The calibration of test equipment shall be traceable to National Standards of measurement.

2.2 Allocation: Continuous Measurement

2.2.1 Where, but for technical or economic reasons, it is agreed that product streams which would otherwise be separately metered to fiscal quality standards may be accounted for by the class of measurement system referred to as "allocation" the target uncertainties are 0.5% to 1.0%. These levels may not always be attainable for technical reasons. The best levels of allocation metering sometimes approach "fiscal" standards.

2.2.2 In order to approach fiscal standards of allocation metering it will be necessary to have separate processing of the product streams which are to be commingled prior to metering to fiscal standards before entry into a common carrier pipeline system.

2.2.3 Allocation metering systems approaching fiscal standards will in most cases use traditional equipment in the design of the metering system. The main relaxation from full fiscal metering standards is likely to be the removal of in-situ proving requirements. The meters would be installed on the outlet of the last separator stage and each train would be nominally identical. The fiscally metered out-turn would then be prorated using the allocation meters.

2.2.4 This method has the advantage of reducing the effect of any systematic errors which may be present in the allocation metering system but are masked by the larger overall random uncertainties of the allocation meters.

2.2.5 In circumstances where it is not practicable to fully process the product streams then the next best option will be to place the allocation meters in the outlet pipework of the first stage separator. This option runs the risk of free gas being present in the product streams unless precautions are taken to ensure that the meters are installed in such a position where gas breakout is not likely to occur.

2.2.6 If the choice of allocation meter is not of the traditional variety but is for example a Coriolis or ultrasonic meter, particular care should be taken in matching the expected range of process conditions to the operational envelope of the selected meter type. These newer meters can be particularly sensitive to installation effects or process conditions particularly if there is a risk of free gas being present in the product stream.

2.3 Allocation: Intermittent Measurement

2.3.1 In circumstances where there is no practical alternative, allocation using intermittent or "flow sampling" techniques may be permissible. In most cases this will involve the use of a three phase test separator. These tests are usually conducted on a monthly basis.

2.3.2 In the case of a new development where it is proposed at the outset to use a single production installation to co-produce more than one field then maximum advantage should be taken to make use of the opportunities afforded by a new-build situation to configure the process equipment to maximise the accuracy that the use of a test separator can provide.

2.3.3 Positioning the test separator within reach of the export meter prover may be possible. If that is the case then the small additional investment in a few metres of pipe and some valves offers the possibility of in-situ proving of the test separator meter(s). This, taken in conjunction with the selection of high quality instrumentation and flow computers, will result in the contribution to the overall uncertainty in the measurements used for allocation of the commingled out-turn by the meters being as small as practicable. The main contribution to the uncertainty will then arise from causes basically outside the operator's control. These uncertainties stem principally from the variability of the process conditions in relation to flow rates, densities, water cut, incomplete separation, free gas in liquid streams, liquid carry over in gas streams, oil remaining in the water etc.

2.3.4 One of the new generation of water in oil meters should be installed in the oil leg of the separator to reduce the error in dry oil accounting when the oil stream has a significant water content.

2.3.5 If wells of significantly different physical properties and process conditions are to be allocated using flow sampling techniques then additional precautions will be necessary to ensure that each well is treated equitably in the allocation process. The pressure and temperature in the main production separators may be significantly different from those obtaining in the test separator during different well tests. This will result in a different test GOR from a production GOR. To compensate for this a process simulation should be run for each well on both the test separator and the main production separator. This will enable a correction or "shrinkage" factor to be determined. The use of such a factor should result in the sum of well head production being in closer agreement with the sum of the installation out-turn. Such adjustments have the merit of tending to reduce any systematic differences between wells of significantly different properties when using flow sampling for allocation purposes. This is particularly important if some of the wells are sub-sea completions tied back through long sub-sea flow lines.

2.3.6 In the circumstances where a new satellite field is to be co-produced using existing process equipment on a parent platform the scope for the operation of the test separator to the levels of accuracy achievable in the new-build circumstances described above is severely limited.

2.3.7 If an operator proposes to use an existing test separator to allocate production between different fields then it will be necessary to provide the OGO with full engineering details of the test separator and its instrumentation in order that an evaluation can be made of its likely performance as an allocation flow sampler. In general it is unlikely that pipework modifications would be called for but where there is scope to enhance the metrology by upgrading instruments and flow computers this would normally be required.

2.3.8 Although the provision of permanent in-situ proving facilities for the test separator meters is unlikely to be feasible, consideration should be given to the proving of the meters in-situ using a portable small volume prover. It is recognised that there may be space and access restrictions which would make this approach impractical.

2.3.9 The allocation of the commingled out-turn should be based on the principal of prorating the sums of the well-head production (corrected if necessary for differences between test and production process conditions) from each contributing field. This procedure has the effect of minimising the impact that any undetected systematic errors might have on the equitability of the allocation.

2.3.10 In very exceptional circumstances, where the migration of uncertainties caused by relative flow rates and differing uncertainties of metering methods does not introduce unacceptable bias in the allocation of production, the use of difference methods may be permitted.

2.4 Test Separator for Reservoir Management

2.4.1 Since the test separator may be called on to test wells exhibiting very wide differences in product quality, process conditions and flow rates it is unrealistic to expect universally high standards of metering. The conditions ranging from steady flowing dry oil to slugging flow of high water content oil with significant amounts of produced solids as well as temperature variations from sea bed conditions to 100°C imposes severe limitations on the results achievable. In view of this a wide range of uncertainties is associated with this type of measurement. Typical target uncertainties are 5% to 10%. It is acknowledged that some installations with very favourable operating conditions may improve significantly on these figures.

2.4.2 While a conventional test separator may be equipped with a turbine meter or meters in the oil leg, orifice plate in the gas leg and magnetic flow meter in the water leg there is scope for significant variations in test separator meter configurations. Operators might wish to consider whether Coriolis, vortex shedding, ultrasonic or other meter types offer advantages in the provision of test separator meters.

2.4.3 The majority of wells are tested by diverting the well to be tested from the main production separator to the test separator for direct exclusive testing of the well. There may be circumstances where testing by difference may be a viable or even preferred option. Where circumstances permit there may be advantages particularly with sub-sea satellites for testing by difference. For developments where it is not necessary to provide for round trip pigging the elimination of a sub-sea test line may benefit the field economics.

2.4.4 Special precautions may be necessary when testing satellite wells connected to a parent platform by long sub-sea lines that when switching from production to test that the same flowing tubing head pressure exists under both test and production configurations. Failure to test the well under normal operating conditioned will introduce additional errors to the test data.

2.5 Stand-alone Fields: Offshore Loading

2.5.1 The class of field where the relaxed measurement requirements of 0.5% to 1.0% overall uncertainty is considered appropriate includes those fields which pay no Royalty or PRT and load the product of a single field into shuttle tankers. Offshore loaders where more than one field is commingled prior to loading onto shuttle tankers are unlikely to be considered suitable for this approach to measurement.

2.5.2 While such techniques as on-board tank gauging may have developed to the stage where they are suitable for cargo measurements with the vessel alongside a jetty in a sheltered anchorage they are not suitable for cargo measurement in the dynamic conditions of a disturbed sea state such as occurs frequently in the waters surrounding the United Kingdom.

2.5.3 If operators of offshore loaders in this category having the more conventional type of metering installation wish to operate to the relaxed uncertainty of 0.5% to 1.0% a number of options will be open to them. They should however note that there may be an increased likelihood of "letters of protest" if the relaxed uncertainty results in Bills of Lading differing by more than 0.5% from the out-turn quantities.

2.5.4 New developments in liquid ultrasonic meters have brought the performance of this class of instrument into the target uncertainty range for stand-alone offshore loaders where there is no tax or Royalty due. However the advantages to be gained by adopting these measurement techniques will only be achieved by careful design of the installation and operating procedures. Their use will be considered on a case by case basis.

2.5.5 By utilising clamp-on or spool mounted liquid ultrasonic meters directly in the loading line to the shuttle tanker and eliminating an intervening conventional metering skid, a potential bottleneck may be eliminated. This means that loading rates are only limited by the available pumping power or the rate at which the vessel may receive cargo. The reduction of the time spent on station taking cargo improves the safety status of both the tanker and the production facility.

2.5.6 In order to optimise the performance of this type of meter it is essential that the pipe or spool to which the meter is attached should be of better dimensional accuracy than run-of-the-mill pipe. In order to achieve overall uncertainties in the range 0.5% to 1.0% with an instrument, which is essentially a velocity meter, the internal diameter and circularity of the pipe or spool should be determined to an uncertainty of 0.05%. This may be achieved ether by direct gauging of the pipe or by inferring the effective diameter by appropriate in-situ calibration methods. Manufacturers' recommendations for the necessary upstream straight lengths should be adhered to.

2.5.7 In order to provide the high level of availability and reliability required for cargo measurement purposes it will be necessary to install two meters in series so that in the event of failure in any component of the metering system loading may continue without interruption. This configuration provides a more cost-effective redundancy than having a parallel run with attendant valve, pipework and pressure drop costs.

2.5.8 The provision of a redundant series meter provides comparative data for instrument health monitoring and makes available a meter for the purposes of periodic verification by alternatively cycling the meters to an onshore calibration facility.

PART THREE

Gaseous Petroleum

3.1 Fiscal Quality Measurement

Mode of Measurement

3.1.1 All measurements should be made on single phase gas streams. Hydrocarbon measurements may be in either volumetric or mass units. The choice of measurement should however be discussed with the Department of Trade and Industry (OGO). Volumes should be measured in cubic metres and mass in tonnes.

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

3.1.3 Where gas is subject to custody transfer suitable sampling facilities shall be provided for the purpose of obtaining representative samples. This requirement may be influenced by the type of instrumentation incorporated in the measuring system.

3.1.4 The continuous measurement of gas density is preferred for custody transfer but the density of the gas being metered may, under certain circumstances, be computed from pressure and temperature measurements together with gas composition using a suitable equation of state and agreed computational techniques.

Design-Criteria

3.1.5 Where orifice meter systems are used, the design and operation should comply with ISO 5167-1 1991 but with the additional specifications given below:-

a) Maximum beta ratio 0.6

b) Maximum Reynolds number 3.3×10^7

c) Maximum differential pressure 0.5 bar is preferred. Higher differential pressures may be used where it is demonstrated that the conditions of e), f) and g) are met.

d) The metering assembly should be designed and constructed such that the minimum uncertainties specified in ISO 5167-1 1991 are achieved.

e) The total deformation including static and elastic deformation of the orifice plate at maximum differential pressure shall be less than 1%.

f) The uncertainty in flow caused by total deformation of the orifice plate shall be less than 0.1%.

g) The location of the differential pressure tappings with respect to the orifice plate shall remain within the tolerances given in ISO 5167-1 1991 over the operating range of differential pressures. Where plate carriers utilise resilient seals care must be taken to ensure that the load on the plate caused by the maximum differential pressure does not move the plate out of pressure tapping tolerance.

h) Special considerations may be applicable where pulsations are unavoidable but normally the uncertainty due to any such effects should be kept below 0.1%.

3.1.6 Where metering systems other than orifice plate metering are to be used, the systems together with their flow compensating devices, should be of the types agreed by the Department of Trade and Industry (OGO) (see paragraph 1.2) and should be calibrated over as much of the operating pressure, temperature and flow range as is reasonably practicable. Proposals for any extrapolation of such calibrations and correlations of the operating conditions should be presented.

3.1.7 Secondary instrumentation, line pressure and temperature, differential pressure, flowing density, density at base or reference conditions where appropriate and the flow computers should be specified and their positions in the system should be located such that representative measurement is ensured. In many applications the compositional analysis of the gas is required and it is necessary to provide for gas sampling or on-line analysis.

3.1.8 Sufficient meter runs should be provided to ensure that, at the maximum design field production rate or utility rate, at least one stand-by meter is available. Due consideration should be given to the provision of adequate valves so that individual meters may be removed from service without shutting down the entire metering system.

3.1.9 Consideration should be given during design to the provision of back-up instrumentation to cover the failure of normal instrumentation, and to the on-site calibration of primary and secondary metering equipment.

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

3.1.11 An indication of the overall design accuracy and measurement uncertainty of the metering system together with the sources of error should be given (paragraph 11.1 of ISO 5167-1 1991). The assessment of uncertainties in gas measurement should preferably be calculated in accordance with ISO 5168 1978 (the Appendix 4 contains guidance).

Computers and Compensators

3.1.12 A flow computer should be dedicated to each meter run. Altematively if multiple meter runs are computed by one machine a hot operating standby must be provided to allow maintenance or replacement to be carried out without interruption.

3.1.13 All computer and compensating functions, other than data input conversions, should be made by digital methods. All calculation constants should be securely stored in the computer and should be easily available for inspection. Equipment should be designed so that constants can be adjusted, but only by authorised personnel. After initial agreement of stored constants subsequent changes in the computer should be made only with agreement of the Department. Where it is necessary to use manual inputs of data into the computer, e.g. base density, the use of this data should be automatically logged.

3.1.14 Totalisers on individual and station summators should have sufficient digits to prevent roll-over more frequently than every two months. Totalisers should normally have a resolution of l tonne or 1000 standard cubic metres, or decimal submultiples thereof. Totalisers and summators should be non-resettable and where they are of the non-mechanical type should be provided with battery driven back-up memories.

3.1.15 Where rotary positive displacement or turbine meters are used both compensated and uncompensated flow quantities should be recorded.

3.1.16 Compensation for influencing parameters, such as pressure and temperature, should be carried out in the flow computer by digital methods using approved algorithms.

3.1.17 If it is proposed to use new technology such as time of flight ultrasonic meters then details of the proposed equipment, layout and verification procedures should be discussed with the OGO at the earliest opportunity.

3.1.18 In a gas gathering system the operator responsible for the gathering should ensure that the basic metering data, flow formulae and computational techniques are compatible throughout all the fields connected to the gathering system.

3.1.19 The Petroleum Production Reporting System, agreed between the UKOOA and the Department of Trade and Industry (OGO), calls for the average calorific value (energy per unit volume) of custody transfer gas to be reported to the Department monthly. Provision for the determination of the calorific value of custody transfer gas should be made.

3.1.20 The Department of Trade and Industry (OGO) will require adequate notice (normally at least 14 days) of the factory inspection and calibration of primary and secondary equipment, including flow computers, in order that the Petroleum Measurement Inspectors may witness these tests at their discretion.

3.1.21 Adequate verification or, where appropriate, calibration equipment should be provided to enable the performance of meters, computers, totalisers, etc. to be assessed. Reference or transfer standards shall be certified by a laboratory with recognised traceability to National Standards (via for example, NAMAS).

The Calculation of Design Uncertainties in Flow Measurement using Orifice Plate Meters According to ISO 5167-1 1991; ISO 5168 1978.

3.1.22 The uncertainty in the measurement of a mass flow rate, q_m, should be calculated using the simplified formula given in ISO 5167-1 1991 paragraph 11.2.2 (see appendix 4). Over normal production flowrates the overall uncertainty should be better than ±1.0%.

3.2 Allocation: Dry Gas Measurement

3.2.1 For the purposes of this section the term "dry gas" is taken to mean gas which is at a temperature sufficiently above the dew point that condensation does not occur in the meter tubes upstream of the principal flow measuring element or within the downstream section of pipe between the principal element and the sample take-off point.

3.2.2 In circumstances where the fiscal status of production from different fields using common process or transportation infrastructure does not call for full fiscal quality metering it is normal to refer to the class of measurement system as "allocation" metering. Care should be taken to differentiate between the *process* of allocation where fiscal quality measurement may be required and the *class* of measurement frequently refereed to as "allocation metering" where relaxed standards of measurement may be appropriate.

3.2.3 Target uncertainties for dry gas allocation metering systems will be of the order of 2.0%. In order to achieve this level of uncertainty the basic design of the metering station will be similar to a fiscal quality metering station. The relaxed level of uncertainty is achieved through simplified procedures for the operation and periodic verification of the metering system.

3.2.4 If a multi-path ultrasonic meter is the preferred instrument in a particular application it may be possible depending on the circumstances to dispense with a redundant meter run. The multi-path nature of such instruments may be deemed to provide the required level of redundancy. In order for such a configuration to be accepted it would be necessary to demonstrate that the loss of accuracy suffered by the failure of one chord does not take the system outside the agreed uncertainty and that a spare set of transducers is available to enable full operational capability to be reinstated within a reasonable time.

3.2.5 If it is proposed to operate a single stream metering system the ability to change transmitters under pressure should be fully assessed. If for safety or operational reasons it is not possible to replace transmitters under pressure then suitable isolation valves upstream and downstream of the meter must be provided and the impact of such a configuration on the ability of the installation to meet daily nominations when it is necessary to work on the meter be recognised.

3.2.6 If the proposed allocation metering system is to be installed on a "not normally manned platform" then in order to ensure the required level of availability and to avoid unscheduled visits to the installation it may be necessary to include an appropriate level of redundancy in the instrumentation associated with the meter(s).

3.3 Allocation: Wet Gas Measurement

3.3.1 For the purpose of this section, wet gas is taken to mean gas which is in equilibrium with either water or gas condensate or both in the flowing gas stream. It is not intended to address the measurement of gas with a sufficient liquid content to be deemed two phase flow. The precise value of the liquid-to-gas ratio (LGR) defining wet gas or two phase boundary cannot be stated as it will depend on process variables such as gas velocity, water/condensate ratio, line temperature and pressure. As a guide LGRs greater than about 0.2% for stratified flow and 0.5% for annular mist flow are likely to require two phase flow measurement techniques.

3.3.2 The types of meter presently considered suitable for wet gas metering are; orifice plates with drain holes, Venturis, V-cone meters and ultrasonic meters.

3.3.3 Special precautions over and above those required for dry gas will be necessary in the design and operation of any meter to be used in wet gas.

3.3.4 Recent work with Venturis indicates that there may be acoustic problems and discharge coefficient instabilities at Reynolds numbers below the allowable value stated in ISO 5167-1. As this instrument is potentially very useful in wet gas application, work is ongoing to try to resolve the problem.

3.3.5 If an operator chooses to meter wet gas using a Venturi, the arrangement of pressure tappings quoted in ISO 5167-1 should not be used as this could result in liquid finding its way into the impulse lines of the pressure and differential pressure transmitters. Single pressure tapping on the top of the meter would normally suffice.

3.3.6 When any differential pressure device is used to measure wet gas, corrections should be applied to the discharge coefficient to take account of the liquid content. The methods of Murdock[1] and Chisholm[2] as modified by Jamieson and Dickenson[3] may be used to correct for the effect of liquid content.

3.3.7 As present work to correlate the difference between calculated pressure recovery and measured pressure recovery as a function of liquid content holds the promise of a direct on line measurement of liquid content. All new developments should provide a pressure tapping at the recovered pressure position in the downstream section of the metering tube. This small pre investment offers the prospect in the near future of measuring the LGR continuously on line at a negligible cost.

3.3.8 Operators of existing wet gas metering systems should consider whether the potential benefits of such a system warrant the retrofitting of a suitable pressure tapping.

3.3.9 If wet gas allocation meters are to be installed on not-normally-manned installations redundant instrumentation should be utilised to minimise the need for unscheduled visits to the installation while providing a high level of availability.

[1] J W Murdock, Two Phase Flow Measurements with Orifices. Journal of Basic Engineering 1962.

[2] D Chisholm, Two Phase Flow Through Sharp Edged Orifices. Research Note. Journal of Mechanical Engineering Science 1977.

[3] A W Jamieson and P F Dickenson, High Accuracy Wet Gas Metering. North Sea Flow Measurement Workshop 1993.

3.4 Utility and Fuel Gas Measurement

3.4.1 Where gas is used for utility purposes such as gas lift, oxygen stripping and power generation process quality measurement will generally be considered adequate. The level of measurement uncertainty considered appropriate for this class of measurement system is of the order of 3% to 4%. It will normally be considered sufficient for a single measurement point to be used to account for all utility consumption. However for operational reasons the platform operator may wish to have separate metering for each consumption unit on his installation. This will be acceptable to the OGO. Details of the selected measurement system should be included in the documentation sent to the OGO for review.

3.4.2 If the gas used on an installation does not originate from the field being produced by the parent platform other procedures may be required.

3.4.3 In circumstances where a satellite field is produced using the process equipment of a parent installation then a method of accounting for the amount of gas used in producing a satellite should be provided. In some cases this may involve the provision of dedicated measurement equipment. It may also be possible to account for individual field usage based on the relative proportions of service required. This may take into account such factors as throughput, pumping or gas compression requirements, water treatment or injection requirements and any other service which involves the use of gas in its provision.

3.4.4 If an installation is gas deficient and it is necessary to import gas from a pipeline system for power generation and utilities use then it will normally be necessary to have a "fiscal quality" metering system to account for gas imported as the pipeline will be transporting "fiscally" metered gas.

3.4.5 Gas transported between two installations via a dedicated pipeline for use on the importing platform for utilities purposes may, depending on the fiscal status of the exporting installation, make use of less-than-fiscal quality measurement.

3.5 Flare or Vent Gas Measurement

3.5.1 Flare or vent gas should be measured or otherwise accounted for.

3.5.2 In recent years significant advances have been made in the technologies of flare gas measurement and operators are encouraged wherever practical to measure the quantities of gas flared or vented from an installation. The uncertainties likely to be achievable in flare gas metering systems will be of the order of 5% to 10%.

3.5.3 The term "otherwise accounted for" means the process of accounting for gas flared or vented by difference between the estimated sum of individual well-head gas production and the other measured disposals whether by export, injection or use. It is expected that this method produces uncertainties of 10% to 20% but in some circumstances may be significantly higher. Difference methods of accounting for flare will only be acceptable in exceptional circumstances.

3.6 Test Separator for Reservoir Management

3.6.1 Traditional instrumentation may still be the favoured option for gas field test separator operations. However if wet gas allocation metering is also to be used on the installation then the use of the test separator to determine LGRs takes on an additional importance as well as the reservoir management function.

3.6.2 The use of new technology such as ultrasonic and Coriolis meters may offer significant advantages in terms of space and weight requirements while offering comparable levels of accuracy.

3.6.3 The use of a Coriolis meter in the liquid leg may in some circumstances provide a measure of the proportions of water and condensate in the liquid stream using the density measurement capability with a knowledge of the densities of the produced water and condensate.

PART FOUR

Multiphase Petroleum

4.1 Allocation

4.1.1 No standards exist as yet to assist engineers in designing multiphase metering systems. The difficulty is compounded by the fact that there is no accepted standard for quoting the performance and accuracy characteristics of multiphase meters. It is essential when considering a manufacturer's performance and accuracy statements to understand the implications of accuracy's quoted in different ways. There are three common ways in which multiphase meter accuracy's are presented:

i) % phase volume flow rate.
ii) % total multiphase flow rate.
iii) % gas and liquid flow rate plus absolute uncertainty of water cut in liquid phase.

Method i) is favoured by metrologists and clearly represents performance as stated. This method may not be the most practical for extreme cases of phase fractionation. Methods ii) and iii) while quoting relatively small numbers of the order of 5% to 10% for gas/liquid phase uncertainties and 2% or 3% for percentage water cut may nevertheless exhibit very large individual phase errors of 100% or more depending on the absolute value of the percentage water. A useful guide to multiphase metering is to be found in the Handbook of Multiphase Metering produced by the Norwegian Society for Oil and Gas Measurement in Stavanger, Norway.

4.1.2 Any operator contemplating the use of multiphase metering should make contact with the OGO at as early a stage as possible. The acceptability of such technology for production allocation will depend in large measure on the match between the instrument's operating characteristics and the process envelope and variability. It may in any case be necessary to mount an evaluation programme to assess the suitability of a meter for any particular set of process conditions.

4.1.3 The OGO should be involved in agreeing the design and conduct of any evaluation programme proposed for the purpose of qualifying and instrument for use in a production allocation system. The objectives and acceptability criteria should be agreed in advance with the OGO before the start of any testing. Inspectors from the OGO may, at their discretion, witness the testing of a meter under evaluation.

4.1.4 The first task when considering the use of a multiphase meter for allocation purposes is to decide the levels of uncertainty which are appropriate for each phase. This will depend on the value of the phase and the production rate. Clearly a highly accurate measurement on a phase comprising only a few per cent of the production is unlikely to be either cost effective or necessary. The accuracy with which the hydrocarbon flows can be determined will take precedence over the accuracy of water flows. However water fraction measurement may have a high significance depending on the absolute value of the water cut in any particular multiphase flow.

4.1.5 At present the "universal" multiphase meter covering all flow regimes and all possible phase proportions from 0% to 100% of oil, water and gas does not exist. Consideration should be given at the outset to the possible need to use different types of multiphase meters at the start of production than those that may be required at different stages in the life of the field. A detailed evaluation of the predicted production profiles in terms of the changes to GOR and water cut expected over the life of the field will give some indication of the possible changes in multiphase meters which should be planned.

4.1.6 As these instruments at present have large uncertainties there is a risk that significant systematic errors could be masked by the overall random uncertainties. When considering the use of these meters, good repeatability is an important consideration particularly where the opportunity exists for in-situ calibration. By considering other measurement points throughout the production and transportation system procedures can be devised to establish if any bias exists and steps taken to eliminate it as part of the initial verification. If such opportunities do not exist within the basic design of the production facilities then modifications should be considered to enable verification tests to be performed.

4.1.7 It is not practicable to suggest what verification provisions should be made in this document, as any such provision will of necessity be tailored to the particular type of instrument and the process environment in which it is installed.

4.2 Well Testing

4.2.1 There are a number of options for the use of multiphase meters for well testing. Potential benefits include the elimination of the need for test separators and for subsea satellite developments with long subsea test flowlines. These benefits will only be available if the individual fields' process characteristics are amenable to such treatment. Depending on pipework configuration and deployment strategy of multiphase meters another potential benefit is continuous well monitoring or failing that, frequent well monitoring at, say, daily intervals.

4.2.2 Topside use of multiphase meters may be either on their own or in conjunction with a test separator. A multiphase meter in each well flowline may provide a satisfactory level of well management information without the need for a test separator although such an arrangement makes the extraction of well samples more difficult. In some instances a test separator may be required for multiphase meter calibration and well sampling.

4.2.3 If it is proposed to dispense with a test separator and rely entirely on multiphase metering for well testing then care must be taken to ensure that the full range of process conditions presented by wells is within the performance envelope of the selected meter. If flow rates from the range of wells to be managed by the system is very wide then it may be necessary to install more than one meter to provide cover for the full range of flows and process conditions likely to be encountered. As one meter or type of meter may not cover the range of conditions which may arise throughout the life of the installation consideration should be given at the outset to the possible need to change either the size or type of instrument needed.

4.2.4 In the case of subsea satellite clusters the choice of individual well meters or a single meter on a test manifold should be considered. If the properties of the process fluid are such that round trip pigging is not required the saving of a subsea test line can be significant compared to the costs of subsea multiphase meters.

PART FIVE

Operating Procedures

5.1 Liquid Measurement Systems

5.1.1 The procedures cover the metering of liquid mass and volume with particular emphasis on crude oil measurement, and are based on the operational characteristics to be expected of a typical metering station equipped with turbine meters. Where other types of meter have been approved a variant of these procedures may be appropriate. The performance of individual metering stations will depend on the particular characteristics of both the metering system and flow system and the type of hydrocarbon being metered: therefore deviations from these procedures may be necessary in special cases, for example measurements on very viscous crude oils, or low lubricity fluids such as gas condensate.

5.1.2 Operators are required to submit their proposals for the operation and calibration of their metering systems to the DTI OGO Aberdeen address prior to the commencement of commissioning and operation (see section 3.1.20).

Prover Calibration

5.1.3 Prover loops shall be calibrated at the manufacturer's works by methods described in IP or ISO standards as part of their systems checks, and again after installation on site. One copy of the calibration certificate for each of these and all subsequent calibrations should be sent to the OGO. Such certificates should show the reference numbers of the sphere detectors used in the calibration, and the traceability to national standards of the calibration equipment.

5.1.4 While a metering station is in service, prover loops must be calibrated at a frequency of not less than once a year. Where this is not possible for operational or weather reasons, a two month period of grace will be allowed. Inspection of all critical valves and instrumentation along with the sphere, checking of sphere size, sphericity, etc. should take place prior to calibration. After calibration the sphere detectors and switches should be sealed.

5.1.5 Any maintenance work on the prover that could affect the swept volume, e.g. changes of sphere detectors and switches, should not be undertaken without prior notice to the OGO which will advise if a recalibration is required.

5.1.6 The OGO must be given at least 14 days notice of all prover loop calibrations so that arrangements for witnessing can be made.

Determination of Meter Characteristics

5.1.7 For new or modified meters which are to be operated over a wide flow range covering flow rates below 50% of maximum, characteristic curves of meter factor versus flow rate should be determined for each meter. These curves should cover a range of approximately 20% to 100% of maximum flow rate, subject to any system restriction on flow rate. From these curves the permissible flow rate variations at a given meter factor setting will be determined.

5.1.8 Meters that are to be operated normally only at above 50% maximum flow rate, except during starting and stopping, will not be subject to the above requirement provided it can be shown that a meter factor variation of not greater than 0.1% occurs over the working flow rate range.

Meter Proving in Service

5.1.9 The requirements governing the intervals between turbine meter proving are:-

5.1.10 For a newly commissioned metering station in a continuous production system (as distinct from tanker loading), meters shall be proved three times a week at approximately equal intervals between proving. Provided the meter factor scatter is acceptable to the OGO, this frequency may be reduced to twice a week at the end of the first month, and once a week at the end of the second month.

5.1.11 For the tanker loading systems, the frequency of proving will depend on the duration of the loading and the individual production system characteristics. The frequency of proving will therefore be subject to the approval of the OGO on an individual basis.

5.1.12 Meters must also be proved:-

(a) When the flow rate through the meter changes by a significant amount - this change in flow will depend on the gradient of the meter's flow characteristics in any particular installation (see Section 2.0) and would normally be such that a change in meter factor greater than 0.1% does not arise from the change in flow rate. If the change in flow rate is a scheduled long-term change then the meter(s) should be reproved at the first opportunity. If the flow rate change is unscheduled then the meters should be reproved if the estimated duration of the changed flow is 6 hours or more.

(b) When any significant change in a process variable such as temperature, pressure or density of the liquid hydrocarbon occurs for extended periods as for flow in (a) above that is likely to cause a change in meter factor of 0.1% or more. In typical North Sea production systems practical values of these limits are of the order of 5°C temperature, 10 bar pressure and 2% density.

(c) If scale or wax deposition occurs then a higher frequency of proving may be necessary until the deposition problem can be overcome.

5.1.13 Where meter types other than turbine meters are in use, the type and frequency of meter factor proving by the Licensee will be determined on an individual basis by the OGO after consultation with the Licensee. Account will be taken of the meter type, process fluid and operational load cycle. Where meters employing novel technology are to be used, extra evaluation periods and tests will usually be required before acceptance of a long-term operational schedule can be determined.

Meter Factors

5.1.14 Meter factors should be based on the average of at least five proof runs. All consecutive five proof runs must lie within ±0.05% of the mean value. Full details of the proof runs, together with flow rates, pressures and temperatures should be entered in the Record of Meter Provings. In particularly difficult situations where process stability sufficient for proving purposes cannot be achieved then a special proving regime may be agreed after consultation with the OGO. The purpose of a non-standard proving regime is to arrive at a good average meter factor which represents the meter's performance under unstable operating conditions. In seeking to determine a meter factor under unstable process conditions it is acknowledged that a significant proportion of the variability in meter factors is not due to the meter's intrinsic repeatability but to the variations in process conditions during the meter proving.

5.1.15 On metering installations where the meter factor is set manually, the change in factor should be done in such a way as to prevent loss in the measured flow. Also, the new factor setting should be checked by a second person who should sign to this effect in the Record of Meter Provings.

General Procedures

5.1.16 Metering stations should be operated and maintained in accordance with the manufacturers' recommendations: particular attention should be paid to flow stabilisation prior to meter proving, checking of block and bleed valves for leaks.

5.1.17 The temperature-compensated totals associated with the individual meters are to be used as the basis of the approved measurements at each metering station, except where the approved measurement is in mass units.

5.1.18 The operator should check the accuracy of the individual meter temperature compensation daily to detect the occurrence of possible errors. Correspondingly, in a mass measurement system a daily check of the mass computation should be done by comparing the totalised mass with that calculated from the individual metered volumes and density meter readings.

Documentation to be kept at the Meter Station

5.1.19 The operator must maintain a log book for the prover detailing all calibrations, sphere detector serial numbers and any maintenance work done on the prover loop and its associated equipment.

5.1.20 A log must be kept for each meter showing details of:-

i) type and identifying particulars including location and product measured;
ii) totaliser reading(s) on commencement of metering;
iii) all mechanical or electrical repairs or adjustments made to the meter or its read-out equipment;
iv) metering errors due to equipment malfunction, incorrect operation etc., including date, time and totaliser readings both at the time or recognition of an error condition and when remedial action is completed;
v) alarms, together with reasons;
vi) any breakdown of meter or withdrawal from normal service, including time and totaliser readings;
vii) replacement of security seals when broken.

5.1.21 The operator must also keep a Meter Proving Record for each meter giving the full details of each proof run. This record may be kept in either hard copy or approved electronic form and should include a running plot, or similar control chart, so that any undue change or fluctuation in meter factors may be easily detected.

5.1.22 A manual log or automatic recording should also be kept, at intervals of not more than 4 hours, of the following parameters;-

i) all meter totaliser readings;
ii) meter flow rates (also relevant meter factors), pressure and temperature, and (if measured continuously) density;
iii) any change in meter pulse comparator register readings.

One of these sets of readings should be recorded at 24.00 hours, or at the agreed time for taking daily closing figures if different.

Other parameters such as liquid density and percentage BS & W content should be recorded at agreed intervals, if not already included in the automatic log.

5.1.23 Records of parameters such as meter flow rate, liquid temperature and density should be kept at the metering station for at least 4 months.

5.1.24 All above records should be available at all reasonable times for inspection by the OGO.

Direct Reporting to the DTI Oil and Gas Office (OGO)

5.1.25 Operators should notify the OGO prior to any major maintenance or re-calibration work on the metering and proving system. The OGO should also be notified, preferably by telephone or fax, when any abnormal situation or error occurs which could require significant adjustments to the totalised meter throughputs.

5.1.26 If a flow or density meter should require removal for maintenance work or replacement, a fax should be sent to the OGO by notification detailing the serial numbers of the meters concerned and the reasons for the action taken.

5.1.27 When corrections to meter totalised figures are required due to known metering errors, a formal report should be submitted to the OGO detailing the times of the occurrence, totaliser readings at start and finish, required corrections to these readings, and reasons for the errors occurring.

5.2 Gaseous Measurement Systems

5.2.1 These procedures cover the metering of petroleum in the gaseous phase. They will also be appropriate for gas at high pressure when it is sometimes referred to as a "dense phase fluid". By far the largest number of gas metering stations serving the UK and UKCS gas production industry use orifice plate meters. These procedures primarily address this type of metering station. Many of the provisions will be applicable to metering stations employing other measurement technologies with variations as appropriate.

5.2.2 Pre-commissioning. Operators are required to submit their proposals for the operation and periodic verification of their metering systems to the OGO prior to the commencement of commissioning and operation. These will include proposed calibration intervals for the ancillary instrumentation.

5.2.3 The operator should prepare a schedule of pre-commissioning tests which are designed to demonstrate the operability of salient aspects of the metrology. In particular there shall be an examination of the interior of the meter tubes and of the orifice plates to ensure that they conform to the relevant provisions of the standard.

5.2.4 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" plates to avoid damage to the primary elements for long-term metering service. Instruments which may be susceptible to damage or malfunction if exposed to foreign matter should be isolated from the process for the first 24 to 48 hours after start-up. Instruments most likely to be affected are densitometers and gas chromatographs. During this period the flow computers should preferably use a default gas composition to calculate the gas density at operating conditions or use a keypad value of gas density representative of the operating conditions. The computer should be returned to "live input" density as soon as the clean-up is complete.

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

5.2.6 At 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. With new developments in differential pressure measurement and calibration there may be scope for new offshore differential pressure verification procedures.

5.2.7 Detailed procedures for the verification of ancillary instrumentation such as pressure, temperature, gas chromatography, density and relative density where appropriate should be prepared for review by the OGO.

5.2.8 Sampling systems for product characterisation may use conventional methods or where appropriate on-line gas chromatographs.

5.2.9 Calibrations should be carried out using test equipment which is dedicated to the metering systems and is traceable to National Standards (via for example, NAMAS).

5.2.10 The recalibration frequency for each component in the system should be included in the procedures document. It is expected that initially the calibration frequency for most components will be monthly. As a history of the stability of the instrumentation is built up it may be appropriate to increase the intervals between recalibrations. As this would constitute a change in the "method of measurement" prior consent must be sought by the operator before any relaxation of calibration procedures can be granted. In order to support such an application it will be necessary to show that the instruments remain within tolerance on a number of successive recalibrations and are returned to service in the "as found" condition.

5.2.11 The Department may consider a recalibration schedule based on "health checking" procedures in circumstances where signal data analysis systems are in place to monitor the condition of the instrumentation and indicate when an instrument is moving out of its specification. A full justification should be supplied if an operator wishes to adopt such procedures. This should include an analysis of the impact such procedures would have on the overall uncertainty of the metering system.

5.2.12 When calculating the overall uncertainty of metering installations operators should use realistic "field" values for the uncertainties of the ancillary instrumentation rather than the manufacturers' claimed values. The uncertainties claimed by manufacturers for their equipment is usually the best the equipment is able to deliver under ideal laboratory conditions.

5.2.13 In the case of differential pressure transmitters it is important to use realistic field values as the choice of uncertainty value has an impact on the setting of the change over point for systems with high and low range transmitters.

5.2.14 The tolerances used when recalibrating ancillary instrumentation should be set at a level which, while not being so tight as to make their achievement under field conditions extremely difficult, should not be so lax as to risk compromising the overall target uncertainty for the class of measurement in question.

5.2.15 When density is calculated from a compositional analysis and process conditions of pressure and temperature using an approved equation of state, the accuracy of the ancillary instrumentation has an additional significance. Typical sensitivities of calculated density to process variables are;

Variable	**Change**	**% Change in Density**
Pressure	1%	1.0
Temperature	1°C	0.7
Molecular Wt	1%	1.6

5.2.16 When carrying out an examination of an orifice plate in the field it is not necessary to conduct a full gauging examination to ISO 5167-1 tolerances. The main points to look for in a field inspection of an orifice plate are, plate flatness, cleanliness, freedom from damage to the plate surfaces and particularly damage or rounding of the sharp edge.

5.2.17 It may from time to time be necessary to examine the condition of the meter tubes in pressure differential metering systems, (orifice plate or Venturi) to ensure that corrosion, erosion or contamination has not occurred to an extent likely to affect the accuracy of the meter. These examinations may be considered necessary if periodic plate examinations show persistent contamination. Particular attention should be paid to the section extending 2 pipe-diameters upstream of the orifice plate and to the condition of the penetration of the pressure tappings through the meter tube wall. If flow conditioners are used these should also be examined.

5.2.18 Where other meters are used such as turbine meters or multi-path ultrasonic meters singly or in combination and appropriate operating procedure and procedures for periodic verification should be discussed at the design stage with the OGO.

5.3 Multiphase Measurement Systems

5.3.1 As operating experience in the field with multiphase meters is at present extremely limited, it is not proposed to give detailed guidance on operating procedures for this class of instrument.

5.3.2 Operators should discuss the details of their proposed operating procedures at an early stage with the OGO. All opportunities for periodic verification should be investigated. This is likely to involve plans to make use of scheduled shut downs of contributing production streams to establish continued satisfactory operation of the meter. Contingency plans should also be in place to make opportunistic use of unscheduled shut downs to provide supporting evidence of meter performance.

5.3.3 As the technology is developing rapidly, operators should keep a watching brief on developments which may refine their instrumentation capability through increasingly sophisticated signal-processing techniques. As our understanding of multiphase metering advances there is significant scope to use advanced signal processing techniques to get more and better information from the existing multiphase metering hardware.

APPENDICES

Appendix 1

Addresses and Contacts

The Department of State with responsibility for the oil and gas industry is The Department of Trade and Industry (DTI). Within the DTI the day-to-day responsibility for carrying out the Government's policies rests with the Oil and Gas Division. The full address is:-

Department of Trade and Industry
Oil and Gas Division
1 Victoria Street
London SW1H 0ET

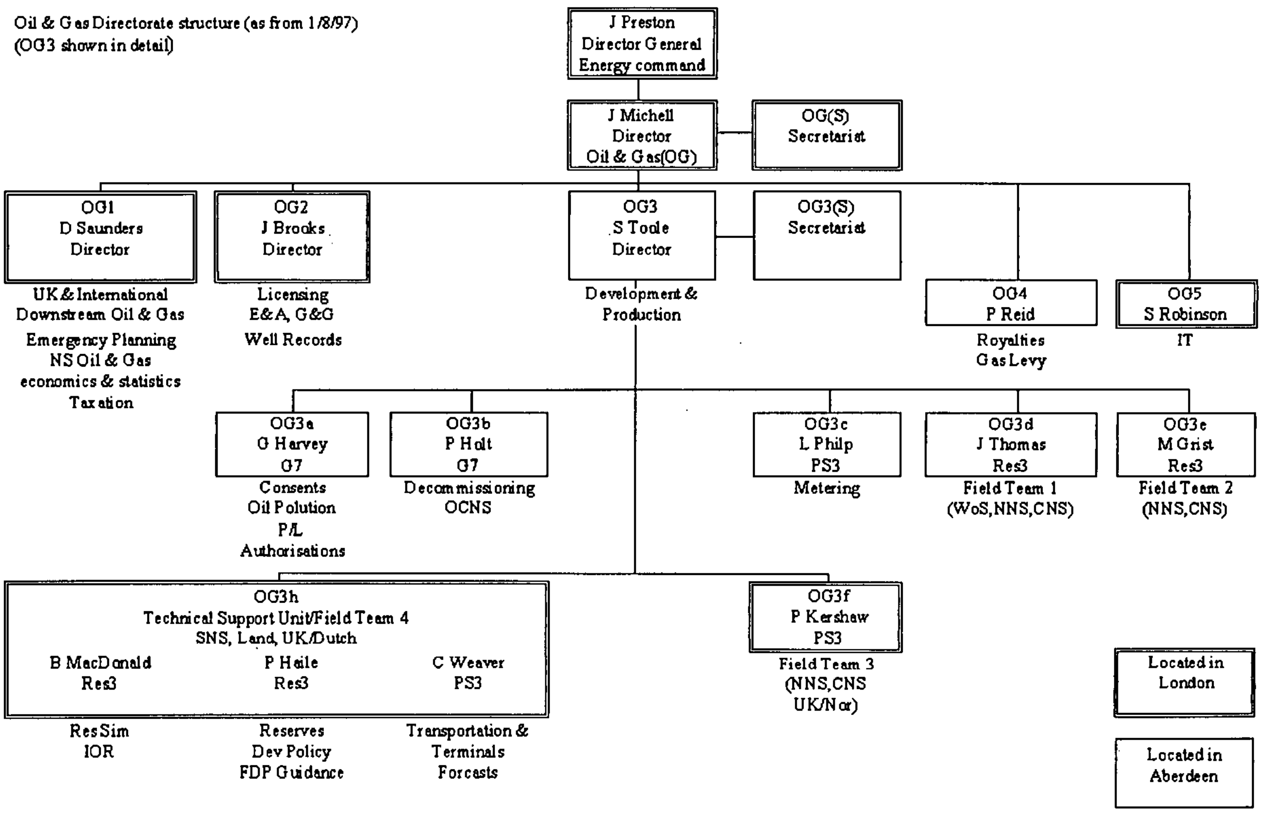
The administration of the Division's responsibilities for petroleum measurement are handled by the Branch 3, OGO. This office is located in Aberdeen and handles all petroleum measurement issues for the UK and Continental Shelf as a whole.

The address is:-

Department of Trade and Industry
Oil and Gas Office
Atholl House
86 - 88 Guild Street
Aberdeen
AB11 6AR

Enquiries telephone	01224 254064
Fax (thermal)	01224 254089
Fax (plain)	01224 590210

Oil & Gas Directorate structure (as from 1/8/97)
(OG3 shown in detail)



Appendix 2

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.

The DTI Petroleum Operations Notice Number 6 is reprinted below for convenience.

DTI - PETROLEUM OPERATIONS NOTICE

No. 6

MEASUREMENT OF PETROLEUM

1. Production licences for both landward and seaward areas incorporate a Model Clause which requires the Licensee to measure by methods customarily used in good oil field practice and from time to time approved by the Minister all petroleum won and saved from the licensed area. It is, therefore, necessary for the Licensee to submit his metering proposals to Petroleum Measurement Inspectors for approval, and it is advisable to do this at the early design stage of the metering station. Petroleum Measurement Inspectors should be contacted for all metering proposals for oil and gas at the address given below in section 5.

2. The Licensee will be required to submit following information:

   (a) A complete specification of the metering station with dimensioned drawings and relevant descriptive literature. Sufficient information should be included to enable a check on the design of the metering station to be made.

   (b) A description of the proposed operating procedure including routine calibrations and checking of equipment for maintenance of accuracy.

   (c) Specimen calculations indicating how reported quantities of oil or gas production are obtained giving correction factors proposed for converting meter and instrument readings to standard conditions.

3. It should be noted that:

   (a) Petroleum Measurement Inspectors must be advised in sufficient time to witness factory tests such as prover loop calibration, systems check, flow tests, etc.

   (b) Before start up and commissioning of a metering station an inspection by a Petroleum Measurement Inspector may be carried out. The operator will be expected to provide the Inspector with all relevant data and information, and to carry out such tests as the Inspector may reasonably require. Reasonable notice should be given to the Petroleum Measurement Inspector as to when an operator will be ready for a pre-start up inspection.

   (c) No alterations to a metering system may be carried out without the previous consent of a Petroleum Measurement Inspector.

4. The method of reporting petroleum production and the details required is the subject of a separate Notice PON No. 7.

Any enquiries regarding this Notice should be addressed to:

The Head of Metering.

Department of Trade and Industry
Oil and Gas Office
Atholl House
86-88 Guild Street
ABERDEEN
AB11 6AR

Telephone	01224 254064
Facsimile	01224 254089

The DTI Petroleum Operations Notice Number 7 is reprinted below for convenience.

DTI - PETROLEUM OPERATIONS NOTICE

No. 7

REPORTING OF PETROLEUM PRODUCTION

1. The Department of Trade and Industry requires Licensees to make monthly returns of petroleum production in accordance with the requirements of the Minister under the above model clauses concerning "Keeping of Accounts" and "Returns". These returns, known as the Petroleum Production Reporting System, must be in computer compatible format as specified by the Oil and Gas Division in the Petroleum Production Reporting System, Data Reporting Format (DRF).

2. The PPRS DRF, which is also known as the Blue Book, specifies the detailed format of the required returns. Copies of the DRF and guidance on creating returns are available from Russell Hornzee, Oil and Gas Data Manager, at the address given at the bottom of this Notice.

3. Operators who are due to commence production must ensure that they can make returns in accordance with the standards specified in the PPRS DRF and must ensure that the proposed format of a return is made prior to the commencement of production in order that the Department may approve the format.

4. This notice does not apply to the reporting procedure for landward fields in production prior to 1 January 1978.

Any enquiries regarding this Notice should be addressed to:

The Data Management Team.

Department of Trade and Industry
Oil and Gas Division
1 Victoria Street
London SW1H 0ET

Telephone 0171 215 5128
Fax 0171 215-5237

Appendix 3

Reference Standard Documents

3.1 Institute of Petroleum,
61 New Cavendish Street,
London W1M 8AR,
United Kingdom.

Petroleum Measurement Manual
Part VI Sampling.
Part VII Density.
Part X Meter Proving.
Part XIII Fidelity and Security of Measurement Data Systems.
Part XV Metering System. Section 1 A Guide to Liquid Metering Systems 1987.

IP 200 (API 2540; ASTM D1250) Petroleum Measurement Tables 1980.
Vol. VII Table 54A Generalised Crude Oil, Correction of Volume to 15°C Against Density at 15°C.
Vol. IX Table 54C Volume Correction Factors for Individual and Special Applications, Volume correction to 15°C Against Thermal Expansion Coefficients at 15°C.
Vol. X Background, Development and Computer Documentation.
Petroleum Measurement Paper No. 2.
Guidelines for Users of the Petroleum Measurement Tables (API Std 2540; (IP200); ANSI/ASTM D 1250) - September 1984.

3.2 American Petroleum Institute
1220 L Street, Northwest,
Washington D.C. 20005,
U.S.A.

Manual of Petroleum Measurement Standards.
Chapter 4 Proving Systems.
Chapter 5 Liquid Metering.
Chapter 6 Metering Assemblies.
Chapter 8 Sampling.
Chapter 9 Density Determination.
Chapter 10 Sediment and Water.
Chapter 11.2.1 Compressibility Factors for Hydrocarbons, 600 to 1074 Kg/m^3.
Chapter 11.2.1M Compressibility Factors for Hydrocarbons 350 to 637 Kg/m^3.
Chapter 12 Calculation of Petroleum Quantities.

3.3 ISO (International Organisation for Standardisation)
Case Postale 56
CH-1211 Geneva 20
Switzerland

ISO 2714	Liquid Hydrocarbons - Volumetric measurement by displacement meter systems other than dispensing pumps.
ISO 2715	Liquid Hydrocarbons - Volumetric measurement by turbine meter systems.
ISO 3170	Petroleum Liquids - Manual sampling.
ISO 3171	Petroleum liquids - Automatic pipeline sampling.
ISO 3675	Crude petroleum and liquid petroleum products - Laboratory determination of density or relative density -- Hydrometer method.
ISO 3735	Crude petroleum and fuel oils - Determination of sediment -- Extraction method.
ISO 4124	Liquid hydrocarbons --Dynamic measurement --Statistical control of volumetric metering systems.
ISO 6551	Petroleum liquids and gases - Fidelity and security of dynamic measurement - cabled transmission of electric and/or electronic pulsed data.
ISO 7278	Liquid hydrocarbons -- Dynamic measurement -- Proving systems for volumetric meters.
ISO 5167-1	Measurement of fluid flow by means of pressure differential devices.
ISO 6796	Natural gas -- Calculation of calorific values, density, relative density and Wobbe index from composition.

A number of relevant international standards are at the Draft International Standard (DIS) stage. When these documents are adopted as full ISO standards they should be included in the list of standards to which reference would routinely be may in arriving at the design of a metering system.

3.4 British Standards Institute
389 Chiswick High Road,
London W4 4AL,
United Kingdom

Many British Standards are now uniform with international standards and where this is the case are issued by the British Standards Institute as dual numbered standards. BS 1042 is one such standard. However only part one of the British standard is uniform with the ISO equivalent, ISO 5167-1. The other parts of the British standard give guidance on the use of orifice plates with drain holes and the effect on discharge coefficients of non-ideal installation. The additional parts of the British standard are a useful source of practical guidance.

BS 1904	Industrial Platinum Resistance Elements.

Appendix 4

Gas Uncertainty Calculations

4.1 The percentage uncertainty E_x of a variable x can be substituted for the relative uncertainty $\frac{\delta x}{x}$ throughout this equation (equation 2).

4.2 The uncertainties used should be those with a confidence level of 95%. At this confidence level uncertainty can be assumed to be equal to twice the standard deviation of measurements. If no information is available for the uncertainty of any particular variable an estimate should be made of the highest and lowest probable true values. The uncertainty should then be taken as half the difference between these values.

4.3 The uncertainty in C should be taken from ISO 5167-1 paragraph 8.3.3.

4.4 The uncertainty in the expansion factor ε should be taken from paragraph 8.3.3.2 of ISO 5167-1.

4.5 The uncertainties in D and d should be taken as those given in ISO 5167-1 paragraph 11.2.2.3.

4.6 The uncertainty in the differential pressure, $E_{\Delta p}$, should include the uncertainties in signal conditioners or converters and any other transmission component. These uncertainties should be combined with the transducer uncertainty on a root-sum-square basis. This procedure also applies to the derivation of the uncertainty in the measurement of the operating density, $E_{\rho 1}$.

4.7 The uncertainty of the computer should be included by means of an additional term, $(E_{cm})^2$under the square root sign in equation 2, (equation 3).

4.8 Where volume flow q_V is being computed, the uncertainty in the measured value of density at base conditions $E_{\rho b}$, should be derived, giving consideration to the principles of paragraph 31.

4.9 The term $(E_{\rho b})^2$ should be included under the square root sign in equation 3. (equation 4).

4.10 If the operating density is calculated from measurements of pressure, temperature compressibility factor, and molecular weight then the term $\frac{1}{4}(E_{\rho 1})^2$ should be deleted from equations 2, 3 and 4, and the following terms substituted (see equation 5), respectively,

$$\frac{1}{4}(E_{P1})^2 + \frac{1}{4}(E_{T1})^2 + \frac{1}{4}(E_Z)^2 + \frac{1}{4}(E_M)^2$$

where E_{P1} is the percentage uncertainty in the measured operating pressure etc.

4.11 The uncertainty of a meter tube should be calculated at the design flow rate and one third of this flow rate.

4.12 In the statement of uncertainty of flow rate it is not necessary to distinguish between random and systematic components.

4.13 Where the gas flow is shared equally amongst a number of meters of identical design arranged in parallel the uncertainties in the factors C, the discharge coefficient and epsilon should not be considered to be randomly distributed between the meters. The following procedure for calculating the uncertainty in the total flow, E_Q, should be performed. Considering a single meter, the sum of the first two terms under the square root sign in equations 2 to 5 should be called $(E_X)^2$.

The uncertainty in the total flow, E_Q, is then given by;

$$E_Q = \left[(E_X)^2 + \left(\frac{E_Y}{\sqrt{N}} \right)^2 \right]^{1/2}$$

Where N is the number of meters in parallel, and $(E_Y)^2$ is the sum of the remaining terms in equations 2 to 5.

Equations modified for ISO 5167-1:1991 uncertainty equation (Section 11.2.2).

EQUATION 1

$$\frac{\delta q_m}{q_m} = \left[\left(\frac{\delta C}{C}\right)^2 + \left(\frac{\delta \varepsilon}{\varepsilon}\right)^2 + \left(\frac{2\beta^4}{1-\beta^4}\right)^2\left(\frac{\delta D}{D}\right)^2 + \left(\frac{2}{1-\beta^4}\right)^2\left(\frac{\delta d}{d}\right)^2 + \frac{1}{4}\left(\frac{\delta \Delta P}{\Delta P}\right)^2 + \frac{1}{4}\left(\frac{\delta \rho_1}{\rho_1}\right)^2\right]^{1/2}$$

EQUATION 2

$$Eq_m = \left[(E_C)^2 + (E\varepsilon)^2 + 4\left(\frac{2\beta^4}{1-\beta^4}\right)^2(E_D)^2 + \left(\frac{2}{1-\beta^4}\right)^2(E_d)^2 + \frac{1}{4}(E_{\Delta P})^2 + \frac{1}{4}(E\rho_1)^2\right]^{1/2}$$

EQUATION 3

$$Eq_m = \left[(E_C)^2 + (E\varepsilon)^2 + \left(\frac{2\beta^4}{1-\beta^4}\right)^2(E_D)^2 + \left(\frac{2}{1-\beta^4}\right)^2(E_d)^2 + \frac{1}{4}(E_{\Delta P})^2 + \frac{1}{4}(E\rho_1)^2 + (E_{cm})^2\right]^{1/2}$$

EQUATION 4

$$Eq_v = \left[(E_C)^2 + (E\varepsilon)^2 + \left(\frac{2\beta^4}{1-\beta^4}\right)^2(E_D)^2 + \left(\frac{2}{1-\beta^4}\right)^2(E_d)^2 + \frac{1}{4}(E_{\Delta P})^2 + \frac{1}{4}(E\rho_1)^2 + (E_{cm})^2 + (E\rho_b)^2\right]^{1/2}$$

EQUATION 5

$$Eq_v = \left[(E_C)^2 + (E\varepsilon)^2 + \left(\frac{2\beta^4}{1-\beta^4}\right)^2(E_D)^2 + \left(\frac{2}{1-\beta^4}\right)^2(E_d)^2 + \frac{1}{4}(E_{\Delta P})^2 + (E_{cm})^2 + (E\rho_b)^2 + \ldots\right.$$

$$\left.\frac{1}{4}(E_{P_1})^2 + \frac{1}{4}(E_{T_1})^2 + \frac{1}{4}(E_Z)^2 + \frac{1}{4}(E_M)^2\right]^{1/2}$$

EQUATION 6

$$E_Q = \left[(E_X)^2 + \left(\frac{E_Y}{\sqrt{N}}\right)^2\right]^{1/2}$$

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.