IRAQ

MINISTRY OF OIL

IRAQI NATIONAL CODE FOR MEASUREMENT OF HYDROCARBON FLUIDS

FISCAL & CUSTODY TRANSFER

MEASUREMENTS

1st Edition	Final version handed over to the Ministry of Oil	12th October 2007

INDEX

1.0 SCOPE

1.1 INTRODUCTION

This measurement code has been developed for use by the Oil and Gas Operators located in Iraq for the measurement of their hydrocarbon products. The requirements of this measurement code apply to all Fiscal / Custody transfer measurements.

The application of this measurement code for Fiscal / Custody Transfer measurements is mandatory for all Oil and Gas Operators engaged in the production, refining, transportation and distribution of related hydrocarbon products which pass between their facility battery limits in Iraq and including the imports and exports of hydrocarbons.

The International Standards and recognized Measurement Procedures which are incorporated in this code shall be enforced by the Ministry of Oil further referred to as MoO acting as the Regulator.

The purpose of this measurement code is to facilitate a transparent auditable process with regard to sustaining trust and auditable measurement confidence in the transfer of liquid and gaseous hydrocarbons products for financial transactions between the Oil and Gas Operators and between the Oil and Gas Operators and the MoO. Revenue receipts such as fiscal payments from certain facilities and refineries or other locations shall be based on Fiscal / Custody transfer measurements and follow regulatory accountability.

This measurement code is administered by the Iraq MoO relevant department responsible for all aspects of the implementation [to be completed by MoO]. An update/review of the measurement code shall be carried out by the MoO every two years.

The principles prescribed in this code lay down the broad standards for compliance as required in Sections 1-9.

1.2 ABBREVIATIONS & DEFINITIONS

For explanation of abbreviations and definitions of certain terminology please refer to section 3.0

1.3 PURPOSE OF THIS MEASUREMENT CODE

This measurement code contains important information for all Oil and Gas Operators in Iraq and shall be used in the design, construction and operation of Fiscal / Custody transfer measurement systems for which the Minister of Oil approval is required under Iraqi laws and regulations.

This code shall be interpreted as representing *minimum* requirements. They shall *not* be viewed as prescriptive, and whatever the measurement system agreed, alternative techniques to those described in this document may be considered provided that they can be shown to give a similar or greater level of uncertainty and reliability. For the typical measurement systems refer to Section 9.0 Appendices.

In order to assist the Oil & Gas operator in establishing the appropriate method of measurement the MoO shall be contacted at the (Pre-Project Plan conceptual stage). Early consideration of measurement requirements shall enable the Oil and Gas operator to complete the screening of options at an earlier stage and so minimise the effort in system evaluation. This procedure is intended to avoid the pitfall of proceeding with a measurement system design that is not acceptable to the MoO.

The procedure to be followed regarding new developments, or modifications to existing measurement systems, is summarised by the Flow Chart illustrated in figure nr.01 at the end of Section 1.0

1.4 REGULATORY FRAMEWORK

The principal legislation that applies to the Oil and Gas production industry and downstream operations, particularly in relation to Fiscal / Custody transfer metering of hydrocarbon products, is as follows:

The Iraq Oil & Gas Law

When the Iraq Oil & Gas Law is enacted, this measurement / metering code will cover any arrangement under the proposed law wherever applicable.

1.4.1 MoO INSPECTION

In order to satisfy the Minister of Oil that no unauthorised alterations to the approved method of measurement have been made, inspectors from the MoO may at their discretion physically inspect metering systems at any stage from construction through commissioning into operation.

1.4.2 METHOD OF MEASUREMENT

Where liquid and gaseous hydrocarbons products are transferred between facilities via a pipeline that serves as a common transportation route for a number of Oil & Gas Operators then the “method of measurement” shall include:

- The measurement of hydrocarbons for the incoming and outgoing streams (balancing) shall be measured at the terminal serving the relevant pipeline.
- The allocation procedures and algorithms used to determine each contributing Oil & Gas operator share of the petroleum used at or exported from the terminal.

1.5 PURPOSE FOR WHICH MEASUREMENT IS REQUIRED

The first task in determining the suitability of a proposed measurement system or systems is to identify the purposes for which measurement is required. These broadly fall into the following two categories:

Fiscal measurement

‘Fiscal’ refers to the meter’s service, not its quality.

a) To account for hydrocarbons extracted from the reservoir, processed, transported and distributed.
b) For purposes of import and export.

Custody Transfer measurement

Provide quantity and quality information used for the physical and fiscal documentation of a change in ownership and/or a change in responsibility for hydrocarbons. Gives quality and quantity information in the change of ownership of product.

1.5.1 MEASUREMENT OF HYDROCARBONS

The purposes are to:

i) **Establish** quantities on which revenues are based
ii) **Safeguard** revenues from oil and gas facilities.
iii) **Allocate** terminal out-turns to contributing facilities in shared transportation systems.
iv) **Account** for production of petroleum extracted.
iv) **Account** for petroleum in the form of crude oil, gas, LPG, LNG and all other products movements.
v) **Allocate** production into shared transportation systems from different facilities commingled in shared facilities.
vi) **Account** for quantities of gas flared.
vii) **Account** for quantities of gas used for power generation.
viii) **Account** for quantities of gas used for gas lift or for reservoir pressure maintenance.

1.6 UNITS OF MEASUREMENT

Consistent use shall be made of units of measurement customarily used in good industry and commercial measurement practice. Unit conversion factors shall precisely comply with the industry standards specified.

1.7 MEASUREMENT MODEL CLAUSE

The following rules apply to existing facilities. When the oil & gas law is enacted these will apply to Licensees.

"The following Measurement Model Clause is lifted from the United Kingdom's Petroleum (Production) Regulations (Seaward Areas) 1988, for indicative purposes only. It is this piece of Secondary Legislation which empowers the Department for Business, Enterprise and Regulatory Reform (BERR -formerly DTI) to review and inspect Licensees' measurement proposals.

The Iraqi Oil and Gas law will incorporate an equivalent Measurement Model Clause."

(1) The Oil & Gas Operators shall measure or weigh by a method or methods customarily used in good industry practice and from time to time approved by the Minister of Oil for all hydrocarbons.
(2) If and to the extent that the Minister so directs, the duty imposed by paragraph (1) of this clause shall be discharged separately.
(3) From each part of the licensed area which is an oil /gas facility for the purposes of the Iraq Oil & Gas law,
(4) From each part of the licensed area which forms part of such a facility extending beyond the licensed area, and
(5) From each well producing petroleum from a part of the licensed area which is not within such a facility.
(6) 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.
(7) The Oil & Gas operator 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.
(8) The Minister of Oil 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 Oil & Gas operator shall pay to any such person or to the Minister such fees and expenses for test or examination as the minister may specify.
(9) 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 Oil & Gas Operator 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.

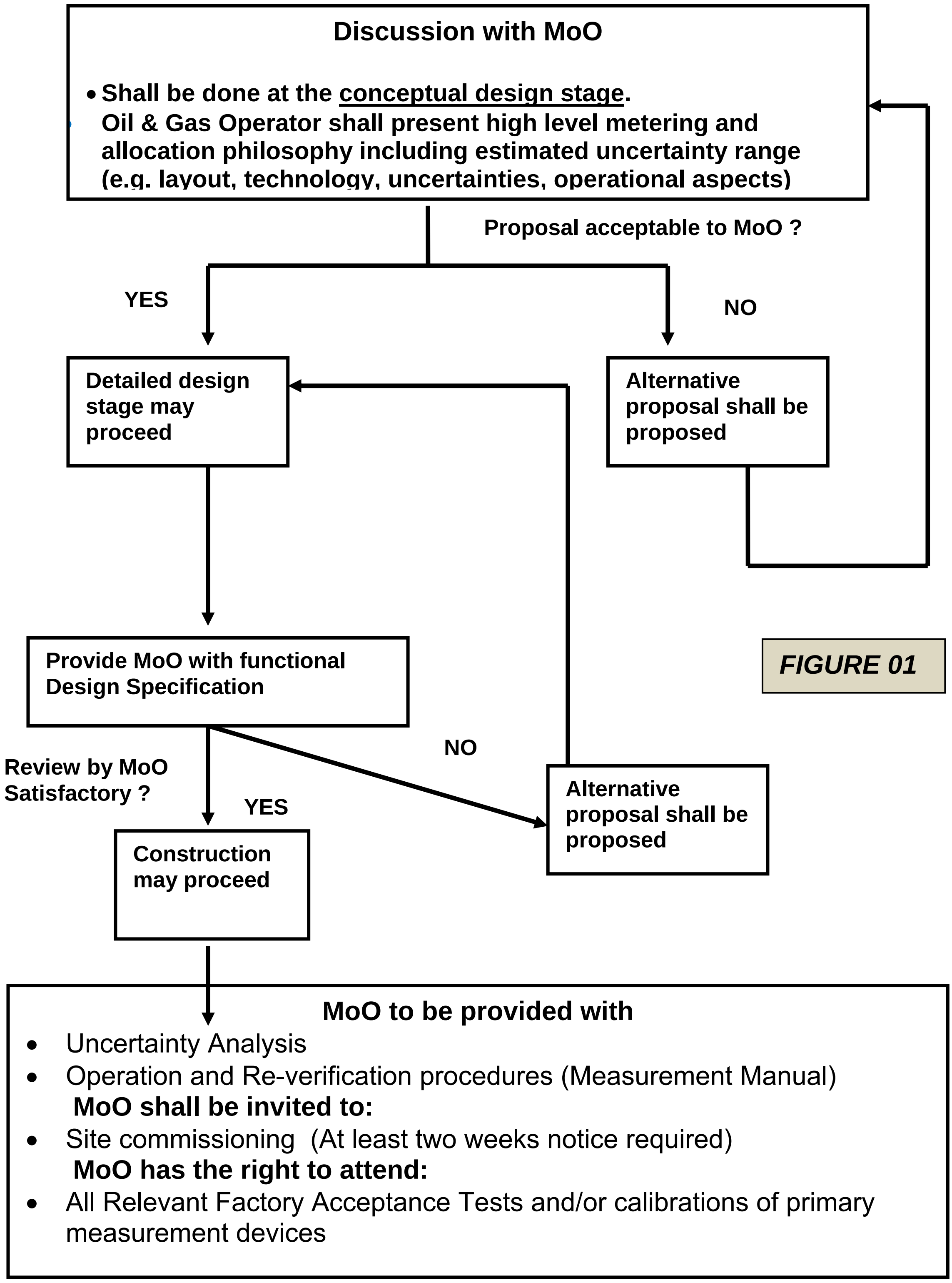

FIGURE 01

MoO LIAISON PROCEDURE

This flow diagram illustrates the procedure that shall be followed when liaising with the MoO when a new measurement system, or modifications to an existing one are proposed.

The measurement code requires that the Fiscal / Custody transfer measurement of hydrocarbon products shall meet the required performance characteristics and required measurement uncertainties.
The measurement process shall be performed at the battery limits of Upstream, Downstream – (refining and processing) and Distribution facilities and shall include 'Fiscal / Custody transfer' measurement of internally transferred products as well as for international markets.
In addition, measurement of stock, gas flared (FUTURE) and facility 'own use' (FUTURE) is included.

<u>This Metering code does not apply to:-</u>
Measurements made within the battery limits of a location for control and monitoring purposes of product streams that do not have an impact on money transfer between Oil & Gas Operators or Oil & Gas Operators and MoO.

1.8 EXISTING ORGANISATIONAL STRUCTURE FOR MINISTRY OF OIL DIRECTORATES & AGENCIES

I MoO Head Office

1. Administrative and Legal department
2. Directorate of Finance and Economics
3. Technical Department
4. Directorate of Reservoir and Oil Field development
5. Directorate of Studies, planning and follow-up
6. Inspector General Bureau
7. Directorate of Internal Audit
8. Directorate of National Manufacturing & Manpower development
9. Directorate of Contracts & Licenses

II Extraction activity (Upstream)

1. North Oil Company
2. South Oil Company
3. Iraqi drilling Company
4. Oil Exploration Company

III Transformation Activity (Downstream)

1. North Refinery Company
2. South Refinery Company
3. Middle Refinery Company
4. Northern Gas Company
5. Southern Gas company

IV Distribution Activity

1. Oil products Distribution Company
2. Gas Filling Company
3. Pipeline Company

V Other departments and Agencies

1. Oil marketing Company (formerly SOMO)
2. Oil projects Company
3. Iraqi Oil tankers Company
4. Oil training Institute of Baghdad
5. Oil training Institute of Kirkuk
6. Oil training Institute of Beji
7. Oil training Institute of Basrah

VI Department for Measurement & Calibration

Newly established department responsible for the implementation of this measurement code.

2.0 MEASUREMENT STANDARDS & GUIDELINES

It is the MoO policy that Fiscal / Custody transfer measurements shall be in accordance with applicable published standards such as API & ISO. There shall be a consistent implementation of the same issue of International Standards and their related calculations especially where different Oil & Gas Operator's measurement installations use a common transportation / pipeline system.
Where similar standards are published such as OIML and Energy Institute (formerly IP) and are equivalent these are also acceptable.

HIERACHY OF STANDARDS

Government (local legislation) law
Metering code
Industry Standards

This section includes the Measurement Standards, Recommendations and Practices (Measurement Guidelines) that shall be used as an integral part of this code. Recognised International Industry Standards, Recommended practices and codes relating to Fiscal / Custody transfer meter design, operation, calibration and maintenance are listed in this section.

International Measurement Standards

Oil & Gas Operators shall make use of the ISO, API or other applicable published Industry Standards (latest version) listed below when considering the design, construction and operation of all Fiscal / Custody transfer measurement systems.

Technical Papers

Technical papers are referred to in the text by the first-named author, e.g. [*Smith*]. The paper details are presented at the end of each section.

Energy Institute (formerly Institute of Petroleum)
61 New Cavendish Street,
London W1M 8AR,
United Kingdom.

www.petroleum.co.uk

Petroleum Measurement Manual

Part	Content
VI	Sampling.
VII	Density
X	Meter Proving
XIII	Fidelity and Security of Measurement Data Systems
XV	Metering System. Section 1 A Guide to Liquid Metering Systems
X	Background, Development and Computer Documentation

Petroleum Measurement Tables IP 200 (API 2540; ASTM D1250)

Publication	Content
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
Petroleum Measurement Paper No. 2	Guidelines for Users of the Petroleum Measurement Tables (API Std 2540; (IP200); ANSI/ASTM D 1250)

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

www.API.ORG

Manual of Petroleum Measurement Standards	
Chapter	**Content**
1	Vocabulary
2	Tank Calibration
3	Tank Gauging
4	Proving Systems.
5	Liquid Metering.
6	Metering Assemblies.
7	Temperature Determination
8	Sampling.
9	Density Determination
10	Sediment and Water.
11.2.1	Compressibility Factors for Hydrocarbons, 600 to 1074 kg/m³
11.2.1M	Compressibility Factors for Hydrocarbons, 350 to 637 kg/m³
12	Calculation of Petroleum quantities
13	Statistical aspects of measuring and Sampling
14	Natural gas fluids measurement
15	Guidelines for Use of the International System of Units (SI) in the Petroleum and Allied Industries
16	Measurement of Hydrocarbon Fluids by Weight or Mass
17	Marine Measurement
18	Custody Transfer
19	Evaporative Loss Measurement
20	Allocation of oil and gas measurements
21	Flow measurement using electronic metering Systems

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

www.iso.org

ISO	Content
1000	SI units and recommendations for the use of their multiples and of certain other units.
10790	Measurement of fluid flow In closed conduits – Guidance to the selection, installation and use of Coriolis meters (mass flow, density and volume flow measurements)
2714	Liquid Hydrocarbons - Volumetric measurement by displacement meter systems other than dispensing pumps.
2715	Liquid Hydrocarbons - Volumetric measurement by turbine meter systems.
3170	Petroleum Liquids - Manual sampling.
3171	Petroleum Liquids - Automatic pipeline sampling.
3675	Crude Petroleum and Liquid Petroleum Products -Laboratory determination of density or relative density Hydrometer method.
3735	Crude Petroleum and Fuel Oils - Determination of sediment extraction method.
4006	Measurement of Fluid Flow in Closed Conduits - Vocabulary and symbols.
4124	Liquid Hydrocarbons - Dynamic measurement; Statistical control of volumetric metering systems.
5167-1	Measurement of Fluid Flow by Means of Pressure Differential Devices; Orifice Plates, Nozzles and Venturi Tubes Inserted in Circular Cross-section Conduits Running Full. *(Current Revision)*
6551	Petroleum Liquids and Gases - Fidelity and security of dynamic measurement cabled transmission of electric and/or electronic pulsed data.
6976	Natural Gas - Calculation of calorific values, density, relative density and Wobbe index from composition.
7278	Liquid Hydrocarbons - Dynamic measurement; Proving systems for volumetric meters.
9951	Natural Gas -Turbine meters used for the measurement of gas flow in closed circuits.
10723	Natural Gas – Performance evaluation for on-line analytical systems.
12213	Natural Gas - Calculation of compression factor.
13443	Natural Gas - Standard reference conditions.
GUM 1	Guide to the Expression of Uncertainty in Measurement.
TR 12765:1998	Measurement of fluid flow in closed conduits – Methods using transit-time ultrasonic flow meters
TR 15377: 1998	Measurement of fluid flow by pressure-differential devices – Guidelines to the effect of departure from the specifications and operating conditions given in ISO-5167-1
TR 3313: 1998	Measurement of fluid flow in closed conduits – Guidelines on the effect of flow pulsations on flow measurement instruments.

When the new documents are adopted as full ISO standards they shall be included in this list of standards.

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

www.bsi-global.com
http://bsonline.techindex.co.uk

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. 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	Content
1042	Measurement of fluid flow in closed conduits; pressure differential devices.
1904	Industrial Platinum Resistance Elements. (adopted as dual or triple numbered CEN and national standards with identical text)
7405	Guide to the selection and application of flow meters for measurement of fluid flow in closed conduits
7965	The selection, installation, operation and calibration of diagonal path transit time ultrasonic flow meters for industrial gas measurement

American Gas Association
400 N. Capitol Street, N.W.
Washington, DC 20001
U.S.A.

www.aga.org

Report	Content
No. 8	Compressibility and super compressibility for natural gas and other hydrocarbon gases.
No. 9	Measurement of Gas by Multipath Ultrasonic Meters
No.10	Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases

Gas Processors Association
6526 E 60th Street
Tulsa, OK 74145
U.S.A.

www.gasprocessors.com

Report	Content
GPA 2165, 1995	Standard for analysis of natural gas liquids mixtures by gas chromatography.

3.0 TERMS & DEFINITIONS

List of abbreviations

API	American Petroleum Institute
AGA	American Gas Association
ASTM	American Society for Testing and Materials
BS&W	Basic Sediment & Water
CAPEX	Capital Expenditures
OPEX	Operational Expenditures
Custody Transfer	API MPMS Chapter 1 (Vocabulary) Provide quantity and quality information used for the physical and fiscal documentation of a change in ownership and/or a change in responsibility for hydrocarbons. Gives quality and quantity information in the change of ownership of products
EI	Energy Institute, formally called Institute of Petroleum
GPA	Gas Processors Association
Fiscal measurement	“Fiscal” literally means ‘concerned with government finance/regulation
ISO	International Organisation for Standardisation
Oil & Gas Operator	Any company National or International operating in Iraq in the hydrocarbon upstream, mid-stream or downstream sector
Meter Factor	A dimensionless term which is obtained by dividing the volume that passes through a meter (determined by a prover) by the indicted volume flowing through the related meter.
OIML	International Organization of Legal Metrology
Proving	Establish a meter factor using a prover
RASCI Chart	Chart for identifying Organisational Roles & Responsibilities
Third Party	A surveying organisation that is an independent from the MoO & Operators
Traceability	Property of a result of a measurement whereby it can be related to appropriate standards, generally international or national standards, through an unbroken chain of comparisons.

Expanded Uncertainty	Quantity defining an interval about the result of a measurement that may be expected to encompass a large fraction of values that reasonably be attributed to the property to be measured.
Water draw	The term applied to the technique of calibrating a pipe prover by displacement of liquid, normally water, from the prover into a volumetric or gravimetric tank.

4.0 GENERAL REQUIREMENTS

4.1 MEASUREMENT APPROACHES

This section includes the measurement approach for various measuring systems and calibration equipment required for Fiscal / Custody Transfer flow measurement. Various metering run configurations are described with general and specific installation data. The equipment selected to achieve the overall uncertainty required shall vary according to the circumstances. The overall objective shall be to ensure that the measurement technique, related uncertainty and operating procedures are appropriate for the fluid service in question.

It also deals with defining the measurement approach for Fiscal / Custody Transfer at metering stations at border crossings. The selection of the primary measurement device is discussed and checked with the related metering uncertainty that shall be required.

Reference shall also be made to the section 9.0 Appendix - Typical applications for measurement systems.

4.2 TERMS OF REFERENCE

This section is intended as a high-level overview of typical measurement options at the early stages of a facility.

The decision as to which measurement solution is appropriate for a particular operation is arrived at following discussion between the Oil & Gas operator and the MoO. A measurement approach for the facility shall be stipulated, taking into account the technical and economic features of the proposed application.

This section is not intended to be exhaustive or prescriptive, but rather to:

Outline the typical scenarios in which each of the measurement approaches is appropriate.

Describe the typical characteristics of each measurement approach and the typical uncertainties that are potentially achievable with each.

Further guidance on the design, installation and reverification for each Approach are given in section 7.0 of the measurement code.

4.3 NEW SYSTEMS – DESIGN CONSIDERATIONS

INTRODUCTION

This section is intended to provide a 'high-level' overview of important points that shall be considered by Oil & Gas Operators when reviewing potential solutions to measurement applications.

APPLICATION OF SUITABLE TECHNOLOGY

It is the responsibility of the Oil & Gas Operator to ensure that the chosen measurement technology is appropriate to the desired application.

This is a vitally important point. On more than one occasion, meters totally inappropriate to the in-service flow conditions have been commissioned and installed. The costs involved in retro-

fitting replacement meters are likely to be very high – not to mention the potential cost to the Oil & Gas Operator of systematic under-measurement resulting from the use of the meter in conditions for which it was not designed.
Discussion with the MoO is required at as early a stage as possible in the project. Guidance in this area is also available in BS7405.

Nature of Fluids

The measurement system design shall be suitable for the fluid characteristics in question. Careful consideration shall always be given to the nature of the fluid or fluids being measured. In particular:

- Is the fluid likely to be single phase, two-phase (e.g. wet gas), or multiphase?
- Is liquid Newtonian or non-Newtonian?
- If dealing with gas, is the fluid likely to be at or near its dew-point?
- If dealing with liquid, is gas break out likely to occur?
- Are contaminants such as scale, wax, sand and solids likely to occur?

The answers to these and other questions can have a critical bearing on the appropriate choice of meter for a given application.

Flow ranges to be Measured

Certain types of meter have higher flow range capacities than others for the same bore of meter tube. The choice of a meter may therefore impact on the required number of meter runs.
Oil & Gas Operators shall consider the expected flow rates that are likely to occur throughout the life of a facility. Some meters have higher turn-down characteristics than others.

Life of Facility / Field costs

While the MoO recognises the demands to minimise CAPEX costs, the operational life cost of the measurement station shall be taken into account by the Oil & Gas Operator.
Selection of robust high-quality primary and secondary instrumentation can have a critical role to play in reducing life-of-field costs.

Reliability of Instrumentation

The use of high-quality instrumentation is likely to reduce OPEX costs associated with the mean time between failure in service of critical elements of the measurement station.

Maintenance Costs

High-quality instrumentation, though more expensive, is likely to be more stable than its lower-cost counterpart. However, this CAPEX cost is likely to be more than offset through reduced OPEX maintenance costs. The MoO is always ready to agree to reductions in the required calibration frequencies of instrumentation, subject to the demonstration of satisfactory performance and stability.

Reverification Procedures

The cost of reverification of a system shall be considered at the conceptual design stage and.
the MoO informed during the liaison procedure. Refer to the flow chart “Conceptual design discussions with the MoO” section 1.0.

Physical Location of the metering skid

Oil & Gas Operators are asked to consider the physical location of the overall metering skid and the MoO to be informed during the “Conceptual design discussions with the MoO”.

Process Pipework

The piping arrangement before and after the metering skid shall be given careful consideration as this can have a considerable impact on the operation of the system components.
As an example the siting of a metering station at the bottom of a 'U' in the process pipework is not conducive to effective measurement in the long term, particularly in wet gas applications.
The type and location of control valves also requires careful consideration, particularly where ultrasonic meters are to be used. If in doubt, the meter manufacturers shall be also consulted for advice.

- **Gas systems** shall be piped to eliminate liquid contamination e.g. offtake from high points in piping.
- **Liquid systems** shall be piped to minimize gas contamination, e.g. offtake at low points.

Effect of Ambient Conditions

The MoO has experience of metering skids being sited in some of the most exposed locations possible on desert or offshore installations. These have occasionally been in open, rather than closed modules.
While the MoO accepts that there may be safety considerations involved in the use of open, rather than closed, modules, Oil & Gas Operators are reminded that extremes in ambient conditions can have a practical effect on measurement integrity, particularly in areas where assumed values of temperature are used, e.g. gas density measurement.
Oil & Gas Operators shall consider the siting of metering skids, where possible, so that their exposure to extreme ambient conditions is minimised. Lagging and insulation requirements shall thereby be minimised. The use of shelters and sun shields is encouraged for all equipment.

Safety Considerations

Oil & Gas Operators shall consider the ease of access to metering skids, particularly to those areas that require routine maintenance and calibration.
Safety regulations shall be adhered to.

4.3.1 SELECTION OF MEASUREMENT APPROACH

Discussion with MoO

For new projects, Oil & Gas Operators ***shall*** contact the MoO so that a consultation may be arranged in order to discuss the appropriate measurement approach.
It is in the Oil & Gas Operator's own best interest that this meeting takes place as early a stage of the project as possible.
The overall goal is for the measurement technique, uncertainty and operating procedures to be appropriate for the fluid and service in question. The available measurement options may be severely limited by the nature of the fluid measured.
Rather than 'fitting' a measurement approach to a particular project, it is more appropriate to consider at the design stage the economics of the facility and the standard of measurement that shall thereby be supported. Essentially this reduces to whether or not the project economics shall support separation and dedicated processing of fluids prior to their measurement and export. Once the likely fluid characteristics are clear (e.g. 'single phase', 'wet gas') it shall then be clear which of the measurement approaches are realistically achievable.
Fluid characteristics may change throughout the facility life. For example, production from a dry gas field may become wet due to falling reservoir pressure, or the water cut of an oil field may increase to the extent that the measurement solution can no longer be considered a 'single phase' application. Here it may be necessary to establish review dates at which the agreed method of measurement shall have to be reconsidered.
The MoO shall require Oil & Gas Operators for the best standard of measurement consistent with these economic considerations. The Oil & Gas Operator is then expected to ensure that appropriate design and operating procedures are followed.

Once the appropriate measurement approach for a particular development has been agreed, this shall be regarded as no more than a ‘first step’. Whatever the class of measurement system, the target uncertainty shall only be met if adequate supporting measures are taken. The fact that a liquid measurement system has been designed, to, for example, Fiscal / Custody Transfer standards does not in itself imply that its measurement shall meet its design uncertainty of ±0.25%. Rather, that this is the level of uncertainty that such a system may achieve, if operated and maintained correctly.
The appropriate level of maintenance for a measurement system shall of course depend on the measurement approach selected. The overall aim of any maintenance programme is to maintain the measurement system within its target design uncertainty. Fiscal / Custody Transfer systems shall generally require the highest degree of attention.

Economic Exposure

At the facility development stage, the economic ‘exposure’, both to the Oil & Gas Operator and the MoO (where ‘taxable’ petroleum is involved) can be calculated from the product of the following projected parameters:

- Throughput of the metering system (taking into account expected life of facility)
- Uncertainty of the measurement system

This is a useful parameter when determining the appropriate measurement solution. By investing more money in a higher-quality measurement system, it may be possible to reduce the uncertainty and hence the exposure, although to some extent a law of ‘diminishing returns’ may apply. This calculation shall normally form a central part of the preliminary discussions with the MoO.

‘Fiscal’ Measurement - Clarification

‘Fiscal’ means ‘concerned with government finance.

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Measurement Approaches & Typical Metering overall Uncertainties

The following Measurement Approaches are typical:

Approach	Typical total Uncertainty in Quantity Flow Rate Measurement (%)	
	Liquid	Gas
Fiscal / Custody Transfer	0.25	1.0
Allocation	0.5 – 2.0	2 - 5
Well Test	10	

Of these uncertainty limits, only those of Fiscal / Custody Transfer are clearly defined by Industry consensus. The remainder are approximations, reflected by the relatively wide ranges quoted here.
The characteristics of these approaches are discussed in turn in section 4.0. Design, operation and reverification considerations are covered in detail in section 7.0.of this measurement code.

Fuel and Utilities Gas (own use)

Fuel and utilities own gas measurement systems shall normally be designed and operated to meet Allocation uncertainty levels.

4.3.2 "BY DIFFERENCE" MEASUREMENT

Factors affecting uncertainty

The uncertainty of a quantity measured 'By Difference' depends on the following factors:

- The measurement uncertainty of each of the other elements of the allocation system.
- The relative proportion of the 'by difference' quantity to total allocation system throughput.

This uncertainty is therefore not a static value, as the second of these, in particular, is subject to change.

New Measurement Systems

Oil & Gas Operators of facilities where measurement 'By Difference' is proposed are expected to provide details of the anticipated uncertainty throughout facility life, taking into account the factors listed above.

Existing Measurement Systems

Oil & Gas Operators of facilities where 'By Difference' measurement is already in place are expected to place the uncertainty of their measurement under continuous review, for example by means of 'dynamic modelling' using Monte Carlo simulation methods.
There are measurement systems in Iraq that would by normal standards be Custody Transfer quality but where 'By Difference' Measurement has been agreed. The MoO shall be contacted if measurement uncertainty exceeds the levels defined above (i.e. 0.25% for liquid mass, 1.0% for gas mass).
Where the Government's financial exposure becomes unacceptably high, the Oil & Gas Operator shall be required / instructed to retrofit 'direct' measurement techniques.

Use of Statistical Uncertainty Models

There is considerable scope for the use of statistical uncertainty models in this area. These are potentially very powerful tools, enabling both MoO and Oil & Gas Operator to determine where maintenance shall be targeted in order to gain the maximum return in improved measurement uncertainty.

4.3.3 SELECTION OF PRIMARY MEASUREMENT DEVICE

Introduction

The selection of an appropriate primary measurement device is a critical step in any measurement approach. BS 7405 provides useful guidance in this area.

Liquid Hydrocarbons

The most commonly used primary device for Fiscal and Custody Transfer levels of measurement of liquid hydrocarbons is the turbine meter, normally with a facility for in-situ verification with a pipe or compact prover. The use of master meters for verification purposes may also be suitable for smaller-scale applications.
Coriolis meters are also widely used for liquid hydrocarbon flow measurement, both as primary devices and as 'master meters'. They are particularly suitable for the measurement of LPG or stabilised condensate.
The use of positive displacement meters shall be considered for flow measurement of highly viscous and non-Newtonian fluids.
The use of multi-path 'spool-piece'-type ultrasonic meters for Fiscal / Custody Transfer applications is now well established.
Where single-phase clean service flow cannot be guaranteed (for example, in separator metering applications) measurement challenges become significantly more pronounced. The correct choice of meter shall be influenced by process flow considerations. Gas breakout and high water cut can have significant adverse effects on the operation of meters. Separator design can often be enhanced to minimise the impact of either or both of these factors.

Gaseous Hydrocarbons

For dry gas applications the orifice plate is still the most widely-used meter for Fiscal / Custody Transfer measurement of large volumes of high-pressure gas. However, their effective operation is critically dependent on the rigorous application of the provisions of AP 14.3 or ISO 5167. In particular, the flow shall be single phase if an uncertainty of 1.0% or less is required. The Oil & Gas operator shall also be able to demonstrate that the orifice plate and meter tubes are in an acceptable condition and the need for regular inspection of these shall always be accommodated.

Multi-path ultrasonic meters have been in use for a number of years now and have gradually gained acceptance for use in Fiscal / Custody Transfer and Allocation applications. A large amount of data has been collated on these devices and the first standards have been published and are currently under review.

Coriolis meters are now widely accepted as being capable of performing at Fiscal / Custody Transfer uncertainty levels in gas applications.

Turbine meters have traditionally been used for low pressure and smaller volumes of gas. More recently, with the facility to calibrate at higher pressures, turbine meters have also been used for high pressure and higher volume clean gas applications. However, these meters remain particularly susceptible to damage by any liquids present in the gas and they are not therefore regarded as suitable for use in fiscal metering applications.

Wet Gas and Multiphase Hydrocarbons

Orifice plate meters, Venturi meters, V-cone meters and, to a lesser extent, ultrasonic meters, have been widely used in wet gas applications.

When an orifice plate is used in applications where a significant amount of liquid is present (for example, in separator metering applications) the use of a plate installed in a vertical run with flow downward is strongly recommended. Drain holes in orifice plates installed in horizontal pipe have also been tried and the additional uncertainty introduced is likely to be small compared with that which would be introduced by a build-up of liquid upstream of the plate. Recent independent tests have shown that the V-cone meter may be particularly suited to wet gas metering applications. A new generation of 'hybrid' meters is presently under development.

3 phase application

For 3-phase applications where oil, gas and water are to be measured simultaneously, the optimum choice of meter is very much application-dependent.

New Technology

The MoO encourages Oil & Gas Operators to continue to develop and deploy new technology, consistent with the retention of a satisfactory degree of measurement integrity.

Where the Oil & Gas Operator wishes to use a relatively new technology or to deploy existing technology in a novel setting, the MoO may:

- Require that the Oil & Gas Operator establishes an evaluation programme
- Wish to be involved in the design, implementation and evaluation of the findings of any such programme.

4.3.4 FISCAL / CUSTODY TRANSFER MEASUREMENT

Fiscal / Custody Transfer Measurement Scenario

Economic considerations aside, Fiscal / Custody Transfer uncertainty levels for a new project shall be generally regarded as appropriate when either of the following conditions applies:

1. Hydrocarbons from the facility are subject to a Revenue Tax ?
2. Hydrocarbons from the facility are part of an allocation system containing hydrocarbons from other sources that are subject to Revenue Tax.

There may be commercial factors (e.g. pipeline agreements) that dictate the need for Fiscal / Custody Transfer uncertainty levels.

Fiscal / Custody Transfer uncertainty levels shall generally only be achieved by the implementation of the highest quality design, installation and operating practices. It can be expensive to achieve, but offers the benefit of reducing financial exposure to potentially prolonged and undetectable systematic mismeasurement.

Guidance on the installation, operation and verification of such systems is presented in detail in Section 7.0 Measuring & Calibration Equipment of this measurement code, for liquid and gas systems respectively.

However, there are some high-level features common to both, which are dealt with here.

System Design

Fiscal / Custody Transfer measurement systems shall employ tried-and-tested measurement techniques designed and installed to recognised industry standards, where these exist.

Where the Oil & Gas Operator wishes to employ ‘new’ technology in such an application due regard shall be given to section 4.3.3 above.

Maintenance and Operation

The correct maintenance and operation of a Fiscal / Custody Transfer measurement system plays a critical part in helping the system achieve its uncertainty target. This will normally require dedicated, on site measurement staff to achieve an acceptable level of measurement integrity.

Appropriate day-to-day operation of a measurement station is the critical factor.

The lack of full-time, on-site, presence of dedicated metering personnel is only acceptable for Fiscal / Custody Transfer applications provided the following concerns have been addressed fully:

Responsibilities

The responsibilities for the day-to-day operation of the measurement station shall be clearly defined, and the relevant personnel trained to an acceptable level. The MoO may require evidence of the training received by these personnel, and details of any independent competence assessment involved. For hydrocarbon liquid metering systems reliant on meter proving, particular attention shall be given to the theory and practice of proving, and the correct practice to be followed with regard to the acceptance of the results of meter proves (section 7.9 of this measurement code refers).

Operational Procedures

These procedures shall be readily available at all times. Particular attention shall be paid to alarm-handling; both in terms of responsibilities for checking alarms, and the procedures to be followed in the event that they are found to be active.

Remote Metering Support.

When active alarms or other measurement issues are encountered, there shall be available at all times an expert point of contact for the on-site operating personnel.

The acceptability to the MoO of these strategies may depend on the provision of a remote monitoring capability.

In general, maintenance schedules for the reverification of primary and secondary instrumentation shall initially be as frequent as economically justifiable. If a ‘calibration’, rather than ‘health-checking’ regime is proposed, initial recalibration frequencies shall typically be monthly. These may subsequently be relaxed once confidence in the system has been demonstrated.

4.3.5 ALLOCATION MEASUREMENT

Allocation measurement refers to *continuous* measurement by which a quantity of hydrocarbon, measured to Fiscal / Custody Transfer standard, is attributed to different sources.
For the measurement of a field's hydrocarbons to achieve allocation levels of uncertainty, dedicated processing facilities for that facility shall be required.
The best levels of allocation metering may approach Fiscal / Custody Transfer standards. The worst cases may have uncertainty levels only marginally lower than optimal Well-Test systems.
The wide range of uncertainties that may result from this general class of metering is a reflection of the fact that there are no established standards for its deployment, and that there is therefore considerable scope for variation in system design and operation.

Allocation Measurement Scenario

Allocation measurement may be appropriate when the facility economics are not sufficient to support Fiscal / Custody Transfer standards of measurement but are nevertheless able to support dedicated separation and process trains with continuous measurement.

Minimising Measurement Uncertainty

The measurement uncertainty of an Allocation system shall be minimised by the following steps:

- A regular programme of routine calibration for all primary and secondary instrumentation. Particular attention shall be paid to the condition of primary measurement devices, particularly orifice plates if used.
- The installation of a water-in-oil meter in the oil take-off line, although attention is required to obtain the best possible results with these devices.

4.3.6 TANK MEASUREMENTS – FISCAL / CUSTODY TRANSFER

GENERAL

This section covers the minimum requirements for the Fiscal / Custody Transfer measurement of fluids in bulk storage tanks and vessels. Two methods are recognized:

1. A volume based tank gauging system based on level and temperature.
2. Mass based tank gauging system based on hydraulic pressure of the liquid column.

Tank Gauging Techniques

- Manual gauging
- Float and tape Gauges
- Servo Gauges
- Radar Gauges
- Hydrostatic Tank gauging
- Hybrid inventory

Tank Calibration

A custodian shall be appointed by the Oil & Gas Operator company to establish all Inventory gains and losses.
Tank calibrations shall be performed by an accredited 3rd party calibration / surveying company in accordance with the applicable **API or ISO** measurement standards.
The recommended period for re-calibration of tanks (> 10,000 BBL) used for Fiscal / Custody Transfer purposes shall be every 10 years or less. Tanks with a volume less than 10,000 BBL shall be re-calibrated within the period stated in the internal policy of the Oil & Gas Operator.
Tanks shall be always calibrated before being put into service, by an accredited calibration company employing specially trained personnel. Re-calibration shall be required if the tank is modified in any way.
Calibration of tanks shall use one or more of the following methods to obtain the data necessary to prepare a calibration table.

- Tank Strapping
- Liquid calibration
- Optical vertical reference line method
- Optical triangulation method
- Electro optical distance ranging method

Calibration Documentation

Tank calibration table documentation shall be kept at a controlled storage location and shall include as a minimum:

- Calibration date
- ID / Tank Number
- Name of the accredited calibration company
- Standard procedure used for calibration
- Observed density of the liquid in the tank
- Gauge reference point height
- The units of measure used in the table
- Reference temperature of the table
- Floating roof corrections if applicable
- Gauging table in specified increments e.g. feet, inches, 0.25 inches or metre, millimetre,0.1 millimetre

Standards for Tank Calibration

API MPMS

Chapter 2 Tank Calibration
Chapter 3 Tank Gauging

ISO

Petroleum and liquid petroleum products

Standard 4269 Tank calibration by liquid measurement – Incremental method using volumetric meters
Standard 12917-1 Part 1 – Manual methods
Standard 12917-2 Part 2 – Internal electro-optical distance-ranging method

Calibration of vertical cylindrical tanks
Standard 7507-1 Part 1 – Strapping method
Standard 7507-2 Part 2 – Optical-reference-line method
Standard 7507-3 Part 3 – Optical-triangulation method
Standard 7507-4 Part 4 – Internal electro-optical distance ranging method
Standard 7507-5 Part 5 – External electro-optical distance ranging method
Standard 7507-6 Part 6 – Recommendations for monitoring, checking and verification of tank calibration and capacity table

5.0 MANAGEMENT RESPONSIBILITY

Oil & Gas Operators Roles & Responsibilities

The management of the Oil & Gas Operating Company shall ensure that their metrological department has the necessary experienced / trained personnel and related resources to establish and maintain the measurement code. The Oil & Gas Operating Company measurement policy shall be available for MoO review and include statements relating to

improving measurement philosophies, periodic evaluation of auditing procedures and encouraging the improvement of all measurement procedures. The MoO can review or witness any meter provings.
The management of the metrological department and its functioning shall establish, document and maintain the measurement management system (reference ISO 10012) and continually improve its effectiveness.
The metrological department shall identify roles with formal job descriptions and clearly defined tasks such as the calibration of metering equipment. This includes documenting and maintaining the measurement manual with clear definitions of procedures, roles and responsibilities required for the operating, maintaining and calibration of the Fiscal / Custody Transfer and related measurement systems.
A RASCI chart should be used to assist in understanding the relationships of various functions and their role in the measurement-related processes.
A RASCI chart can be an effective way of indicating the involvement of several departments for defined tasks. It illustrates which role each department or person is expected to participate in and helps assist in defining tasks to be included in Role and Responsibility descriptions.
Typical roles which have related measurement responsibilities for compliance with the company standards are:

- Measurement Coordinator (custodian)
- Production Accountant
- Laboratory Manager
- Operations (Instrument technicians)
- Maintenance

Customer Focus

The management of the metrological organization shall ensure that:
Oil & Gas Operators measurement requirements are determined in accordance with the measurement code requirements,

QUALITY OF METERING PROCESS

The management shall define their measurement policy. Measurable quality objectives which support the objectives of the measurement code with technical and administrative guidelines for the supervision and auditing of product movements shall be established.

Examples of the objective performance criteria and procedures for the measurement processes and their control are listed below.

1. Off-spec products shall not be accepted.
2. Incorrect measurements shall be reported within a period of 24 hours.
3. All audits shall be completed by the agreed times by operator to MoO.
4. All Records shall be legible.
5. All training programmes shall be completed per the established schedule.
6. The time for measuring equipment that is out of operation shall be recorded.
7. All periodic maintenance inspections and testing of metering equipment are completed within the specified schedules.
8. Measurements performed by others shall be witnessed regularly by independent inspectors.

Crude Oil international exports

Ship / shore measurement quantity differences shall be specified in the sales contract. Crude oil export loading shall be disputed due to incorrect quantity or quality measurements.

Oil Products

Receipts / deliveries shall be measured to level of uncertainty specified in the sales contract.

Natural Gas

Receipts / deliveries shall be measured to level of uncertainty specified in the sales contract.

General

90 % of all metrological confirmations shall be completed by the agreed times.
Technical training programmes shall be completed by the established schedule.

MoO Management Review

The MoO Management shall ensure at least every two years that the measurement code is kept up-to-date and relevant by regular reviews / improvements. The following items need to be considered as part of this review.

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- Regular and orderly reviews of the measurement code at planned intervals to ensure its continual adequacy, effectiveness and suitability.
- That the necessary resources are available to review the measurement code.
- The results of the management review shall be used to modify the measurement code as necessary, including improving measurement processes. The results of all reviews and all actions taken shall be recorded.

6.0 RESOURCE MANAGEMENT

Responsibilities of metering personnel

The operator management shall define and document the responsibilities of all personnel assigned to the measurement management system.
Personnel responsibilities shall be defined in organization charts, job descriptions and work instructions or procedures including specialist personnel.
This shall include:

- Metering organisation charts
- Metering job descriptions
- Metering personnel instructions / procedures

The **Metering Custodian** shall assume responsibility for the complete coordination of all internal and external liaison of metering matters, management approved changes of metering polices, updating and modifications to internal procedures and regulations.

Competence and Training of personnel

The operator management shall ensure that personnel involved in the measurement management system have demonstrated their ability to perform their assigned tasks. Any specialized skills required shall be specified.
The operator shall ensure that:

- Training is provided
- Needs are identified, evaluated and recorded
- Records of training activities are maintained
- Personnel are made aware of their responsibilities and accountability
- Personnel are made aware of the impact of their activities on the effectiveness of the measurement management system.

Note: Example
Competence may be achieved through education, training / on the job experience and demonstrated by testing or observed performance performed by a competent observer.

- List of the required metering competences
- Training records of metering staff

6.1 PROCEDURES & WORK INSTRUCTIONS

INTRODUCTION

This section is intended to provide Oil & Gas Operators with guidance as to the documentation that the MoO expects to be maintained in connection with Fiscal / Custody Transfer Quality Measurement Stations, both Oil and Gas, as defined in Section 7.0 of the measurement code.
The same principles apply to lower-quality measurement systems, though there shall be less stringent requirements in these cases.
This list is not intended to be exhaustive but rather to provide guidance on the maintenance of a satisfactory degree of traceability in measurement stations. This is to satisfy the interests of MoO Regulator and the Oil & Gas Operators themselves. For example, the ability to calculate the magnitude of a mismeasured quantity, and potentially recover revenue that would otherwise be lost, may depend critically on the ability to identify exactly when a problem arose.
These guidelines have been formulated with the need to avoid duplication in recording data in mind. Proposals to further reduce duplication shall be viewed sympathetically by the MoO provided they do not unduly jeopardise traceability.

SYSTEM DESIGN AND OPERATIONAL DOCUMENTATION

The following documentation shall be maintained at the measurement station:

(i) The latest version of the system's Functional Design Specification

(ii) A full set of up-to-date Operation and Reverification Procedures

All documents shall be kept for a period of 10 years and the MoO has the right to inspect all operator records on request.

STATION METERING LOGBOOKS

Logbooks shall be maintained at the measurement station.

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Electronic archiving

Logbooks have traditionally been of the 'hard copy' type, in a dedicated notebook with numbered pages to demonstrate that no entries have been destroyed. While the MoO has no objection to use of such logbooks, Oil & Gas Operators should consider the use of 'electronic' logbooks, provided that these are suitably secure. This offers a number of advantages – principally, it allows the logbooks to be reviewed remotely. A well-designed electronic logbook would allow a 'filter' to be applied to entries to allow the reviewer to search by category.

Logbook Format

Entries shall be clear and concise at all times, and shall be signed, timed and dated.

The Oil & Gas Operator shall maintain a separate logbook for each metering station.

The Oil & Gas Operator shall consider the use of a 'common equipment' logbook in which to maintain records of work done on equipment or instrumentation that is not specific to any one stream – for example, the sampling system.

For liquid measurement systems using a prover loop, a prover log shall be maintained. This shall contain details of all prover calibrations, sphere detector serial numbers and any maintenance work carried out on the prover and its associated instrumentation.

Meter proving records shall also be maintained. The important parameters that shall be recorded are given in Section 7.0 of this measurement code.

Significant Events

These logbooks shall contain details of all significant events in the operation of the measurement station. A well-maintained logbook shall permit the precise timing of any mismeasurement to be identified retrospectively. It shall allow the observer, e.g. an independent auditor, to establish to what extent the measurement station is able to run 'smoothly', without upset.

Examples of 'significant' events include:

- Any removal of the flow meter, for whatever reason.
- The totaliser readings at the removal from, or introduction of, the stream into service.
- Any 'non-routine' events, such as the failure of any items of instrumentation and any remedial action taken.

Note that this list is not intended to be exhaustive – the Oil & Gas Operator is expected to be able to decide what constitutes a 'significant' event in the operation of a measurement station.

A list of currently-operating dispensations shall be readily available for inspection at all times.

Oil & Gas Operators shall notify the MoO before any major maintenance or recalibration work on the metering system. The Oil & Gas Operator shall seek dispensation from the MoO if they cannot comply with the agreed calibration schedule of a primary element, or in the event of the failure of a flow computer or database.

MISMEASUREMENT REPORTS

Reporting to MoO .

The MoO shall be notified, preferably by E-mail, when any abnormal situation or measurement error occurs which could require significant adjustments to the totalised meter throughputs.

When corrections to meter totalised figures are required due to known metering errors, a formal report shall be prepared. This report shall be sent, preferably by E-mail, to the MoO, and shall contain the following details of the mismeasurement:

- Its start and finish time.
- Totaliser readings at its start and finish.
- The method used to determine its magnitude.
- The reasons for its occurrence.

Records to be maintained

Operational metering records shall also be maintained, 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.

A set of these readings shall 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 % BS&W content, shall be otherwise recorded at agreed intervals if not already included in the automatic log.

All above records shall be available at all reasonable times for inspection by the MoO. Electronic or hard copies are acceptable. Records for the preceding 12 months shall be retained at the metering station.

Records and reporting requirements

To maintain historical data (archives) / records of measurement results

Historical records containing information required for the operation and re-verification of the measurement management system shall be maintained in data archives in a safe controlled location for a minimum of 10 years. Their protection, retrieval methods and retention times shall be established.

Examples of historical records are:

- Meter Proving and measurement results.
- Calibration and verification reports
- Purchasing, operational data
- Non conformance data, customer complaints
- Training, qualifications and historical data supporting the measurement processes.
- Non-conformance reports
- Customer complaints
- Incident reports

FLOW COMPUTER CONFIGURATION RECORDS

Configuration listings for each stream flow computer shall be maintained at the measurement station. Back-up copies of instrument configuration files and calculation software shall be kept to safeguard programming and to provide the level of traceability necessary.

These listings may be of critical importance in the retrospective calculation of any mismeasurement. Any manual change of a normally-fixed parameter shall be recorded in a Controlled Document, giving details of:

- The date and time of the change.
- The previous value of the parameter.

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

An example of a change in flow computer configuration that would need to be reflected in the configuration listing is the change in calibration constants following the annual recalibration of a densitometer.

CALIBRATION CERTIFICATES

The Oil & Gas Operator shall have readily available at the metering station calibration certificates for the following:

- All current test equipment – All calibration equipment shall be traceable to a National Standard and that test equipment has been calibrated at a laboratory accredited by UKAS, or an equivalent authority.
- Elements of the metering system that have been calibrated remotely (for example, orifice plate/meter tubes, differential pressure cells, densitometers).

These certificates shall be either maintained in 'hard-copy' or electronic form.

ROUTINE CALIBRATION RECORDS

Routine calibration records shall be maintained at a metering station. Copies of all calibration reports shall be sent to the MoO on a monthly schedule. These records shall allow the auditor to readily establish:

- That planned maintenance routines have been carried out at the agreed frequency
- The degree of reliability of the secondary test equipment under calibration

The Oil & Gas Operator is encouraged to make these records available. Copies for at least the last 2 years shall be retained. The procedure of reviewing them can be time-consuming and this activity can be profitably pursued before any inspection.
Oil & Gas Operators are strongly encouraged to use an electronic means of maintaining routine calibration records. This may be in the form of one of several commercially-available packages, or it may be developed 'in-house'. However, it shall have the facility to readily summarise the details required in this section
As well as helping to reduce the time spent on these tasks by auditors, a well-designed system can also be of significant help to the Oil & Gas Operator as it significantly facilitates the task of collation of calibrationn records prior to their submission to the MoO in application for the extension of agreed calibration intervals.
This section shall describe the organization that shall oversee and regulate the Fiscal / Custody Transfer installations.
The Oil & Gas Operator shall ensure the availability of sufficient administrative and technical personnel resources to ensure compliance with the measurement code.
Any new Oil & Gas Operator shall submit their metrological organisation and describe their functions to the MoO before operations begin.

- Head Office
- Technical dept
- Admin dept

6.2 PROCEDURES REQUIRED

The Oil & Gas Operators shall be required to maintain documented procedures covering all aspects of the Measurement Management activities. Some examples that the MoO might request during an audit the examination are the examination of the applicable operator's measurement procedures.

1. Metering manuals per system / location
2. Calibration procedures
3. Sampling procedures
4. Equipment verification and certification procedures
5. Report non-conformances
6. Actions taken when seals or safeguards are found damaged, broken, bypassed or missing.
7. List of equipment to be sealed and methods of sealing
8. Prove a liquid meter
9. Verify a gas meter
10. Verify a tank gauge
11. Install a meter
12. Commission a meter
13. Commission a tank gauge
14. Start-up and shut-down meters
15. Maintain a meter
16. Verification frequency
17. Witnessing frequency
18. Responsibilities
19. Turbine linearity / Prover Loop Systems (Master Meter method)
20. Prover re-calibration (Bi-directional / small volume)
21. Temperature and Pressure validation

Environmental conditions for measurement equipment

The environmental conditions required for the accurate / reliable operation of the measurement equipment shall be documented.
Any environmental conditions affecting measurements shall be monitored and recorded. Corrections based on the environmental conditions shall be recorded and applied to measurement results, including uncertainty calculations.

Environmental conditions affecting measurement results can include:

- Temperature and rate of change of temperature
- Humidity and Barometric pressure
- Electromagnetic interference
- Vibration
- Sunlight / UV exposure
- Solids and water ingress

Reference shall be made to equipment manufacturer's specifications giving ranges and limitations of environmental conditions for the correct use of the equipment.
Examples listed below

Field equipment

Meters, provers, transmitters, gauges, tanks, all instruments and equipment utilized in the measurement system components.

Test / Calibration equipment

Dead Weight testers, voltmeters, calibrated volumes, calibration gases all instruments and equipment utilized in the measurement system components.

6.3 OUTSIDE SUPPLIERS OF PRODUCTS AND SERVICES

Criteria for selecting suppliers

The MoO shall set high level equipment selection guidelines and initiate new metering technology test programmes

The Operators shall define an evaluation procedure to ensure outside suppliers possess technical competence to supply measurement systems to MoO standards.
Additionally the operator management shall define and document the requirements for products and services to be provided by outside suppliers for the measurement systems.

Examples:

- **Outside suppliers** shall be evaluated by the operator and selected based on their ability to meet the documented requirements, demonstrate technical competence and possess an internationally recognized Quality control and assurance system.
- **Criteria** for selection, monitoring and evaluation shall be defined and documented
- **Evaluation** results shall be recorded.
- **Records** shall be maintained of the products or services provided by outside suppliers.

7.0 MEASURING & CALIBRATION EQUIPMENT

This Section describes the requirements for measuring and calibration equipment for Fiscal / Custody Transfer measurement of hydrocarbon fluid.

7.1 LIQUID PETROLEUM MEASUREMENT “TERMS OF REFERENCE”

This section of the measurement code is intended for use with liquid petroleum that is sufficiently above its vapour pressure that there is no significant risk of gas break-out at the meter. Where this condition is not met, Oil & Gas Operators are strongly advised to exercise caution in applying the principles and advice provided here.
This module deals with ‘Custody-Transfer’ standard liquid hydrocarbon flow measurement. By industry consensus, this is defined as dry mass flow measurement with an overall uncertainty of ±0.25% or better. The overall uncertainty is derived from an appropriate statistical combination of the component uncertainties in the measurement system.
The equipment used to achieve this level of performance shall vary according to the particular circumstances of each new development or existing facility
A substantial proportion of the metering stations covered by this measurement code are based on ‘conventional’ turbine meter and bi-directional prover loop systems with associated on-line density measurement and automatic sampling. However, an increasing number of Fiscal / Custody Transfer metering systems are making use of alternative technologies, such as ultrasonic meters, for flow measurement. There may be very sound technical reasons for doing so.

7.2 MODE OF MEASUREMENT

Volume or Mass Measurement

Hydrocarbon measurements may be either in volumetric or mass units. The choice of measurement shall be discussed with the MoO.
Volume shall normally be used for stand-alone tanker loading operations. Depending on the system requirements, volume or mass may be utilized for multi-facility pipeline or offshore pipeline with an allocation requirement.

Where the measurement is in volume units, these shall be referred to standard reference conditions such as 60°F temperature. The metering system shall compute referred volumes by means of individual meter temperature compensation and totalisers.
Mass measurement and reporting shall be achieved either by :

a) Measurement of volume flow rate (for example, by turbine or ultrasonic meter) and fluid density
b) Direct mass measurement by Coriolis meter

If the method a) is preferred, the density shall if necessary be compensated to the volume flow meter inlet conditions. Mass flow rate shall then be computed as the product of this density and the measured volume.

7.3 FLOW COMPUTERS

Guidelines for Manufacturers/Operators

TERMS OF REFERENCE

This section is intended to provide manufacturers and Operators with some guidance on points to consider in the design and operation of flow computers for use with Fiscal / Custody Transfer or fiscal oil and gas measurement systems.
These features are generally common to oil and gas systems. Where items are specific to either oil or gas this is indicated.
This is not intended to be an exhaustive list, as this would be beyond the scope of this document. Refer also to API 21.1 & 2 Flow Measurement using Electronic metering Systems.

DESIGN CONSIDERATIONS

Redundancy

Either of the following scenarios are regarded as satisfactorily addressing redundancy concerns in connection with high-quality metering systems:

- a dedicated flow computer may be provided for each meter run;
- multiple meter runs may be computed by one central flow computer, in which case a standby instrument shall be provided so that maintenance or replacement may be carried out without interruption of flow.

Storage of Constants

All computer and compensating functions, other than data input conversions, shall be made by digital methods. All calculation constants shall be securely stored within the computer and shall also be easily available for inspection at the appropriate resolution.
Computer equipment shall be designed such that constants can be adjusted only by authorised personnel. Where it is necessary to use manual data inputs within the computer, for such functions as defaults, establishing fallback values and setting alarm limits, the use of this data shall be automatically logged.
Flow computers and databases shall be designed so that measurement accuracy is not compromised by inadequate resolution on the display of critical constants.
Lack of resolution on the computers' displays can create difficulties in establishing whether the correct values of constants have been entered.

Totalisers

Totalisers on individual and station summators shall have sufficient digits to prevent rollover more frequently than once every two months. The resolution of the totalisers shall be such as to comply with this rollover criterion. Totalisers shall provide resolution sufficient to permit totalisation checks to be completed within a reasonably short time frame.
Totalisers and summators shall be non-resettable and shall be provided with battery-driven back-up or non-volatile memories where they are of the non-mechanical type.
Where external totalisers or summators are not installed, the resolution of the flow computer totalisers shall be such as to comply not only with this rollover criterion, but also allow totalisation tests to be performed to the required tolerance. These totalisers shall also be non-resettable. If the resolution of the totalisers cannot meet both the rollover and totalisation test requirements, consideration shall be given to the provision of a totalisation test function within the flow or database computer.

Flow computer manufacturers shall consider the provision of a separate 'maintenance' totalisation register for use during totalisation checks.

Remote Access

The facility for remote access to a database and flow computers is becoming common. This is a potentially extremely useful feature and its use is strongly encouraged provided adequate data security is provided..

Correction Algorithms

Where multiple meter factors are used in conjunction with approved algorithms to calculate instantaneous flow correction factors, the calculations shall be performed by the flow computer and not within the meter electronics unit.
This applies particularly to the use of calibration 'offsets' applied to ultrasonic meters.

Software Changes

The MoO shall be informed of any proposed changes to the flow computer or database software.
A software version number or configuration certificate shall be accessible to enable changes in software to be identified.
A full set of calculations and input tests shall be carried out when the software is installed in the flow computer.

Alarms

Any alarms used within the flow computer shall be accessible to suitably authorised persons and not 'hard-coded' within the operating software. This shall allow appropriate alarms to be enabled or disabled for use and suitable values to be set for their initiation.
The use of alarms shall be carefully controlled. They provide an important means of drawing attention to potential mismeasurements, especially on systems where metering personnel are not present full-time.

7.4 GENERAL DESIGN & INSTALLATION CRITERIA

Metering stations shall 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.

Meter Runs

A sufficient number of parallel meter streams shall be provided to ensure that, at the nominal maximum design production rate, at least one standby meter shall be made available.

Isolation Valving

Adequate valving shall be provided such that individual meter runs may be safely removed from service without necessitating the shut-down of the entire system.
The Operator shall be able to demonstrate the integrity of all vent and drains systems, particularly those downstream of the meter. For example, the use of 'double-block and bleed' valves, or sight-glasses, or 'spades' shall be considered.

Recirculation Facilities
The MoO 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 details of recirculation and any other non-export flows through the meters shall be recorded. The bypass piping in this section shall have appropriate security, locking and sealing of such.

Sampling System
Fiscal / Custody transfer quality crude oil metering systems shall be provided with automatic flow-proportional sampling systems for the determination of average water content, average density and for analysis purposes.
Sampling systems shall be broadly in accordance with ISO or API Standards. Due attention shall be paid to the recommendations of the IP Petroleum Measurement Manual, Part VI ('Sampling').
Analysis of the samples obtained shall ultimately be used to apportion production to the field from which the liquid hydrocarbons are being measured. They may also form the basis for any Crude Oil Valuation Procedures.
The sampling system is therefore a critical part of any Fiscal / Custody transfer quality measurement system. Any errors introduced through sampling error shall generally have a direct, linear effect on the overall measurement.
As with any sampling system, it is important that properly-designed sampling probes are used and positioned in such a way as to ensure representative sampling.
Sampling flow rates shall be 'isokinetic', as defined by ISO 3171. Sample lines shall be provided with flow indicators to help demonstrate that this condition is met.

Temperature and Pressure Measurement
Temperature and pressure measurement points shall be representative of conditions at the meter inlet and situated as close to the meter as possible without infringing the requirements of the API Measurement Manual. In practice, this means approximately 5 diameters downstream of the meter location.
Temperature measurements that affect the accuracy of the metering system shall have an overall loop accuracy of 0.5°C or better, and the corresponding readout shall have a resolution of 0.2°C or better - this is equivalent to an uncertainty of approximately 0.05% in C_{TL}.
Thermowells shall be provided adjacent to the temperature transmitters to allow temperature checks by means of certified thermometers.
Pressure measurements that affect the accuracy of the metering system shall have an overall loop accuracy of 0.5 bar or better and the corresponding readout shall have a resolution of 0.1 bar or better.

Densitometer Installation
Due attention shall be paid to the recommendations of the Part VII of IP Petroleum Measurement Manual ('Density').
Dual densitometers shall normally be used and shall feature a density discrepancy alarm system (typically 1.0kg/m^3). Where single-densitometer systems are used, high and low set point alarms shall be used.
Provision shall be made for solvent flushing on systems where wax deposition may be a problem.
Densitometers shall be installed to the manufacturer's specification and as close to the volume meters as possible. They shall be provided with thermowells and pressure indicators so that it may be demonstrated that there is no significant difference from the volume meters' inlet conditions. If this is not the case, temperature and pressure compensation shall be applied.

7.5 DESIGN & INSTALLATION CRITERIA TURBINE METER / PROVER

Pulse Counting

The metering signals shall 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.
A pulse comparator shall 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 shall be adjustable, and when an alarm occurs it shall 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 shall 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.

Turbine flow meters

Turbine flow meters shall be provided with backpressure controls, or other means shall be provided to prevent damage by over speed during start up.
For tanker loading applications, flow controls shall be provided to enable automatic ramping up and down of loading flow rates.
All turbine meter applications shall be calibrated for a Reynolds Number range which represent the actual fluid flow.
Calibration curves shall be provided for each turbine meter. Flows shall range from the maximum meter design flow to the minimum flow rate at which the stated accuracy is required.

Prover Loop Design

Prover loops shall preferably be of the bi-directional type to eliminate possible directional bias. The prover loop swept volume shall have a suitable internal lining. The flanged joints within the calibrated volume shall have metal-to-metal contact and there shall be continuity within the bore.
Connections shall 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.
Provers shall be constructed according to the following criteria:

- Unless ‘pulse-interpolation’ techniques are to be used, the number of meter pulses generated over the swept volume shall be at least 20,000 pulses. (This is equivalent to 10,000 pulses between detectors on bi-directional provers.)
- The resolution of the detector/displacer system shall be compatible with the above requirement.
- The displacer velocity shall not normally exceed 3m/s to avoid slippage past the displacer but higher velocities may be acceptable 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 MoO requires the manufacturer to demonstrate an acceptable repeatability during calibration of the prover, such that a minimum of (3) three or more consecutive round trips the range of volumes does not exceed ±0.02% of the mean volume. Alternatively, a statistically equivalent repeatability criterion for small volume provers or meter pulse gating systems may be used.

7.6 DESIGN & INSTALLATION CRITERIA PD METER / PROVER

Pulse Counting

The metering signals shall 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.
A pulse comparator shall 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 shall be adjustable, and when an alarm occurs it shall 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 shall 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.
A separate integral electronic pulse counter shall be mounted on the PD meter as back-up.

Prover Loop Design

Prover loops shall preferably be of the bi-directional type to eliminate possible directional bias. The prover loop swept volume shall have a suitable internal coating. The flanged joints within the calibrated volume shall have metal-to-metal contact and there shall be continuity within the bore.
Connections shall 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.
Provers shall be constructed according to the following criteria:

- Unless ‘pulse-interpolation’ techniques are to be used, the number of meter pulses generated over the swept volume shall be at least 20,000 pulses. (This is equivalent to 10,000 pulses between detectors on bi-directional provers.)
- The resolution of the detector/displacer system shall be compatible with the above requirement.
- The displacer velocity shall not normally exceed 3 meters per second to avoid slippage past the displacer but higher velocities may be acceptable 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 MoO requires the manufacturer to demonstrate an acceptable repeatability during calibration of the prover, such that on (3) three or more consecutive round trips the range of volumes does not exceed ±0.02% of the mean volume. Alternatively, a statistically equivalent repeatability criterion for small volume provers or meter pulse gating systems may be used.

7.7 DESIGN & INSTALLATION CRITERIA ULTRASONIC METERS

For Fiscal / Custody Transfer applications, only transit time multi-path ultrasonic meters shall be used.

Meter Diagnostics

Multi-path ultrasonic flow meters incorporate a variety of functions that can either individually or collectively be employed for ‘health care’ monitoring. Provision for data acquisition shall be made at the design phase, so that this information may be used for ‘foot printing’ and monitoring meter performance.

Meter Reverification

The need to periodically re-verify the meter shall be considered at the design stage.
The use of meter diagnostics alone is not presently regarded as sufficient in this respect. An additional means of meter reverification is necessary. Essentially there is the choice between:

a) The use of a master meter.
b) Removal of the meter for calibration at a recognised test facility.
c) Comparison of the meter with a pipe prover.

Use of Master Meter in By-Pass Line

Shall option a) be preferred, the master meter shall be placed in a by-pass line, with the facility to flow simultaneously through the ‘duty’ and ‘master’ meters for comparison purposes. The master meter shall preferably be a meter operating on a different physical principle (e.g. a helical-bladed turbine meter). However, there may be practical advantages (e.g. the provision of a meter that could potentially be used as a spare) in the use of a second ultrasonic meter. Periodic comparison of the ‘duty’ and ‘master’ meters would immediately reveal the presence of contamination, since the ‘master’ meter shall not have been exposed to the same degree of contamination.
Provision of suitable pressure and temperature measurement points is required at both the ‘duty’ and ‘standby’ stations in order that the appropriate correction volume factors may be applied when comparing the two meters.

Upstream and Downstream Pipework

The straight pipe sections located immediately upstream and downstream of the meter shall be selected, fabricated and installed to ensure minimum impact on the performance of the metering station or the specified measurement uncertainty.
Meter manufacturers shall be consulted regarding the minimum number of straight lengths required upstream and downstream of the meter.

Flow Conditioners

The use of flow conditioners removes one of the principal operational advantages offered by ultrasonic meters, i.e. the absence in the flow line of any flow restriction. However, their use may be necessary in order to address what may be quite serious concerns over possible installation effects.
If flow conditioners are proposed as part of the system design then the type and location of these devices shall be discussed with the meter manufacturer prior to installation. Calibration of the meter shall take place with the flow conditioner and pipe spools in place.

7.8 DESIGN & INSTALLATION CRITERIA CORIOLIS METERS

This section of the measurement code highlights the principal points that shall be borne in mind when designing and installing Coriolis metering systems. ISO 10790 shall be consulted for more detailed guidance in this area.

Flow Profile

Coriolis meter performance is not affected to any significant extent by the presence of a ‘non-ideal’ flow profile at the meter. Coriolis meters are also relatively unaffected by changes in flow profile. These features of the Coriolis meter have the following implications:

a) The configuration of the upstream & downstream pipework is of relatively minor importance
b) There is no need to consider the use of flow conditioners.
c) If the meter is to be removed for recalibration, it is not necessary to ensure that the flow profile at the test facility is representative of that experienced by the meter ‘in service’.

Pressure Drop Across Meter

The pressure drop across Coriolis meters is relatively high. To minimise the potential for 'flashing' of lighter hydrocarbons (with consequent degradation of meter performance) any flow control valves in series with the meter shall be placed downstream of it.

Plant Vibration

Mechanical vibration has the potential to degrade Coriolis meter performance. If the meter is to be installed in an area with high levels of plan vibration, it may therefore be necessary to clamp or mount the meter in order to minimise this effect.

Temperature Effects

Large differentials between the ambient temperature and the temperature of the oscillating tubes of the Coriolis meter may lead to increased error in the temperature compensation routine used to correct the results of the meter's flow calibration to its 'in service' conditions. Where the operating temperature is expected to differ significantly from ambient, the meter shall therefore be lagged in order to minimise this effect.

Meter Orientation

U-tube devices shall be installed with the 'U' vertical to prevent the build-up of gas within the meter body.

7.9 OPERATING & RE-VERIFICATION – TURBINE METER / PROVERS

Turbine Meter K-Factor

The correct operation of these systems is critically dependent on the determination of representative k-factors for the turbine meter. The k-factor used by the stream flow computer (normally that determined at the most recent meter prove) shall at all times be within a predefined value, δ, of the 'true' k-factor being generated by the turbine meter in its current operating conditions.

The value of δ is defined by the Operator at the system design stage. Its value is constrained by the need to retain the overall dry mass uncertainty within ±0.25%, and is typically 0.1%.

Meter Factor

Another factor called a meter factor shall also be established each time the meter is calibrated. By always knowing the k factor, meter performance may be easily monitored by the use of control charts to track meter drift over time.

Turbine Meter Linearity

For new or modified meters that are to be operated over a wide flow range covering flow rates below 50% of maximum, a characteristic 'Performance Curve' of meter factor versus flow rate shall be determined for each meter. This allows the Operator to determine the variation in flow rate that would cause a shift in k-factor of greater than the value of δ referred to in 3.7.1 – essentially this is one of the 're-prove alarm limits'.

These curves shall cover a range from 10% to 100% of maximum flow rate, subject to any system restriction on flow rate. It is recommended that a number of proves (typically 5) are completed at each of these nominal flow rate points, between which intervals of 10% are suggested.

Turbine meters used for fiscal / custody transfer quality measurement of oil are expected to demonstrate a good degree of linearity in their performance curves. The MoO typically expects the linearity of meters to be within ±0.15% across the expected operating range of flow rates.

If the variation in k-factor of a turbine meter under normal operating conditions is significantly greater than the value of δ referred to in this section there shall be an increase in the requirement to re-prove the meter due to excursions the re-prove alarm limits. The resultant

increased wear on the prover system shall inevitably have an adverse effect on the duration of its life in service.
Operators are therefore strongly encouraged to use turbine meters with a high degree of linearity. Any extra expense incurred in their purchase is likely to be more than offset by a reduced requirement to reprove the meters during the lifetime of the installation. The use of flow computer meter factor linearization may also be considered as a viable option in certain cases.

Proving Regime

The requirements governing the intervals between turbine meter proving in a continuous production system (as distinct from tanker loading or batch export systems) are:

- For a newly commissioned metering station, for a new meter, or for a meter which is being returned to service after repair, meters shall be proved three times per week, at approximately equal intervals between proving, for the first month of operation.
- Provided the meter factor performance for this month is acceptable to the MoO, this frequency may be reduced to twice per week for the second month of operation.
- If meter factor performance for this second month is still acceptable, proving frequency may be reduced to a lesser frequency but shall depend on the volume throughput.

After the initial ‘settling in’ period, the appropriate proving frequency is determined by the proportion of k-factor shifts in excess of the value δ referred to in this section (typically 0.1%).
The maximum interval between successive proves shall be no more than 7 days for a stream in continuous operation. Subject to this condition, the proving frequency shall be adjusted so that no more than 5% of proves indicate a k-factor shift in excess of δ.
A meter shall also be reproved

- When the flow rate through the meter changes by an amount sufficient to cause a change in meter factor greater than 0.1%. This amount shall be dependent on the turbine meter’s linearity.
  If the change in flow rate is a scheduled long-term change then the meter shall be reproved at the first opportunity. If the flow rate change is unscheduled then the meter shall be reproved if the estimated duration of the changed flow rate is 6 hours or more.
- 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. These values can be determined by a ‘regression analysis’ of the turbine meters’ response to changes in each of these parameters. In typical production systems practical values of these limits are of the order of 5°C temperature, 10 bara pressure and 2% density.

For tanker loading or batch export systems, the frequency of proving shall depend on the loading operation scheme including use of dedicated ramping meter runs. Depending on the duration of export this may require several meter factors covering ‘ramp up’, ‘load’ and ‘ramp down’ export rates as well as shifts in fluid temperature.
The frequency of proving shall therefore be subject to the approval of the MoO on a case-by-case basis.

Determination of Meter-factors

For normal operating conditions:

- Meter factors shall normally be based on the average of at least five proof runs.
- The meter factor calculated for each of the consecutive five proof runs shall lie within ±0.025% of the mean value of all five.

If it proves problematic to satisfy the above condition, for example due to the continual process instability common on some older installations, then an equivalent statistical method may be agreed with the MoO.

It shall always be borne in mind that the goal is not simply to satisfy the requirement but rather to obtain a representative meter-factor for use until the next meter prove is carried out. Oil & Gas Operators are encouraged to be flexible rather than adhere slavishly to the 'traditional' approach.

The following points shall be considered when devising a strategy for statistical proving:

- If it is not possible to achieve the repeatability criteria within 10 runs, then it may be the case that attempts to obtain a representative m-factor shall be unsuccessful even if many more runs are completed.
- Under these circumstances it is recommended that a simple arithmetic average of a large number of runs is calculated. The number of runs required shall depend on the specific circumstances.
- The poor repeatability may be caused by process instability. If this instability is in some way 'cyclical' then the number of runs shall be sufficient to cover a complete 'cycle', even if this number is relatively large. Alternatively, if the instability is not regular, a smaller number of runs would probably be sufficient.
- A large number of runs may be impractical in certain circumstances, especially those where, due to the large size of the prover or the low prevailing flow rates, the time taken to complete all the proves would be unacceptably high.
- Where the number of averaged prove runs is less than 20, a statistical analysis shall be performed on them in order that 'outliers' can be rejected. This can also be performed when the number of runs exceeds 20, although there the larger total provides some insurance against the undue influence of individual 'rogue' proves.

Data to be Recorded

Full details of the proof runs shall be entered in the record of meter proves, together with the following information:

- Date and time of prove.
- Fluid temperature.
- Fluid pressure.
- Fluid density.
- Fluid water cut.
- K-factor shift from previous meter prove.

This information may be extremely useful as supporting data shall it become necessary to predict m-factors, for example in the event of the failure of a critical element of the meter prover.

Meter-factor Acceptance Criteria

Any unexplained shift in m-factor in excess of 0.1% shall be reverified by a repeat run prior to its acceptance.

The performance of a turbine meter shall be monitored throughout its service in order to detect any short or long-term change in its characteristics. This is normally achieved by the use of a 'Control Chart', which is essentially a graph of the turbine meter's meter-factor history.

Statistical methods may then be employed to assist the operator in deciding whether the result of a meter prove shall be accepted. The IP Petroleum Measurement Manual, Part X (' Meter Proving') shall be consulted for guidance in this area.

Good proving practice is fundamental to the correct operation of any turbine meter/prover loop system, and as such Operators' strategies shall be subject to continuous review by the MoO.

Prover Failure

In the event of the failure of any critical element of the prover the MoO shall be contacted so that an appropriate strategy for the reverification of the turbine meters may be agreed.

In the absence of an effective operational prover, it may be necessary to calculate meter factors.

This may be possible using a combination of flow rate (or meter pulse output frequency), meter temperature, meter pressure, water cut, and meter density, using constants which have been generated on the basis of the historical data for that particular turbine meter by use of standard mathematical 'curve-fitting' or 'regression' techniques.
The use of ‘calculated’ m-factors requires prior authorisation from the MoO. For such a method to be acceptable to the MoO, it is important to ensure that:

- No part of the meter has been modified or replaced since the historical data were gathered.
- Although the range of operating conditions whose data are used shall be as broad as possible, non-typical data ('outliers'), identified according to standard statistical techniques, have not been included in the regression calculation.
- Current operating parameters can be shown to fall within the spread of the historical data to be used.
- The set of historical data, the regression calculations used, and the coefficients calculated for each meter are all recorded for possible scrutiny or verification by the MoO.
- Sufficient computer facilities and manpower are available to process the large number of calculations involved in a timely manner.

Operators shall be aware that where turbine meter performance has been affected by contamination of the meters (e.g. by scale formation on the meter blades), regression analysis may not be appropriate.

Spare Prover Sphere

A spare prover sphere of the appropriate size and material type shall always be available.
This sphere shall be stored such that it does not deform under its own weight. Practical solutions to this problem typically involve the storage of the sphere on a bed of polystyrene beads, or the hanging of the sphere in a sack or mesh sling, (but not a rope cargo net, as the sphere may extrude and deform).

Use of Equipment Outside its Design Capacity

The MoO strongly encourages Operators to keep the suitability of their measurement systems under continuous review, and to replace unsuitable equipment as required. As an example it is recognised that the turbine meters and provers installed on some older installations may now be over-sized with respect to current production rates.
Given the characteristic operating curve of a turbine meter, with a particularly steep slope and ‘hump’ at the lower part of the flow range, this may lead to inaccurate measurement unless the proving frequency is increased.
Quite apart from the increased wear on the prover that this would entail, it may in practice be extremely problematic. If significant flow instability is present, it may become difficult or impossible to prove at all. Alternatively, flow energy may be insufficient to drive the sphere through the prover smoothly or reliably. In such low or unstable flow conditions, temperature, pressure, density, and water content may also fluctuate. As viscosity, which may be affected by each of these parameters, is also a dominant influence in turbine meter operation, meter proving may be especially unreliable.
In such circumstances the Operator is encouraged to consider replacing the meters, employ the alternative proving methods discussed above or the use of a ‘master meter.

7.10 PROVER CALIBRATION

The calibration of the prover is probably the most significant single event in the operation of any measurement station that relies on proving for the reverification of its flow meters. Any error introduced at this stage shall persist until the prover is recalibrated – this may be a year or more later – and all flow meter calibrations in the interim shall be subject to this error.
Inadequate preparation on the part of the Oil & Gas Operator has the potential to lead to delays in the completion of the calibration process. It is in the Oil & Gas Operators own interest that the

calibration is completed without any unnecessary delays (consistent with the correct calibration procedures being followed). The cost of the calibration, direct and indirect, shall thereby be minimised, as the Calibrating Authority is normally paid on a daily rate, and any deferment of production caused by the calibration procedure shall be minimised.
Section 7.14 contains some important guidance for Oil & Gas Operators to help ensure that the prover calibration proceeds as smoothly as possible.
Prover loops shall be calibrated at the manufacturer's works by methods described in **API, 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 shall be sent to the MoO.
These certificates shall contain the following information:

- Prover identification number with witnessed signatures in the supporting documentation.
- All certified volumes between each set of detector switches at reference temperature & pressure
- The reference numbers of the sphere detectors and detector seals used in the calibration
- Prover internal diameter and wall thickness
- Prover steel expansion coefficients
- The value of Young's modulus for the prover steel.
- Details of the traceability to national standards of the calibration equipment

The values of these constants shall not change from year-to-year without the prior approval of the MoO.
The MoO shall be given at least 21 days notice of all prover loop calibrations so that arrangements for possible witnessing can be made.
Any maintenance work on the prover that could affect the swept volume (for example, changes of sphere detectors and switches) shall not be undertaken without prior notification of the MoO. The MoO shall advise if a recalibration is required.
Inspection of all critical valves and instrumentation along with the sphere, checking of sphere size, sphericity, etc. shall take place prior to calibration. After calibration the sphere detectors and all vents and drains shall be sealed.

Recalibration Frequency

While a metering station is in service, prover loops shall normally be calibrated at a frequency of not less than once per year. There are certain circumstances under which the MoO may permit the interval between successive prover calibrations to be extended to 5 years, on the basis of historic stability and low production rates. Further details of these conditions are given in section 7.13
Where the agreed interval between successive calibrations has to be extended for operational or weather reasons, a two-month 'period of grace' shall be allowed. Operation beyond this period requires dispensation from the MoO. Any agreed delay shall not be carried forward to the next calibration. For example, if an annual calibration is delayed by 2 months, the next calibration shall be due in 10 months' time.

Acceptance of Results of Prover Calibration

For a prover base volume calibration to be acceptable, it shall be based on 3 (three) consecutive round trips where the range of volumes is within ±0.02% of the mean of these volumes.
The MoO expects the values of base volumes obtained to agree to within ±0.02% from year to year. There is a degree of flexibility in the interpretation of this limit, depending on the ease with which the initial repeatability criterion is met - i.e. it may be interpreted as meaning ±0.02% rather than ±0.020%.
For example, a result with a shift of 0.024% from the previous year's value would not be acceptable as a first attempt, but would perhaps be acceptable if it was obtained after several

days of previously unsuccessful attempts to obtain 3 runs which agree to within ±0.01% of the mean.
Any shift of >0.025% shall certainly be verified by a repeat calibration at a different flow rate. The difference in flow rate shall be at least 25%, if operating conditions permit.
The Oil & Gas Operators shall seek approval from the MoO before any shift in excess of 0.02% is accepted.

Calibration using Water as the Process Medium

The MoO prefers that calibrations are carried out using water. However, under certain circumstances the use of process fluid at line conditions may be justified using the master meter method.
If the levels of stability referred to can't realistically be achieved then the use of water, rather than the process fluid, shall be seriously considered by the Oil & Gas Operators.
There are number of reasons why calibration on water may be desirable. For example:

- Calibration of the prover on product may result in the deferment of production.
- There may be concerns that the required level of process stability may not be realistically achievable.
- The calibration may be completed more rapidly using water, given the better levels of temperature stability achievable, and this may result in a cost saving for the Oil & Gas Operators.
- There may be environmental or safety concerns over the use of hydrocarbon as the flowing medium.

Where the Oil & Gas Operators is considering the use of water then prior consultation with the MoO is required.
At the moment there is no evidence to suggest that the use of water introduces significant additional uncertainty to the calibration procedure. However, shall such evidence come to light then the MoO may wish to review its non-objection to the use of water as the calibration medium.

7.11 MASTER METER IN-SITU RE-VERIFICATION OF TURBINE METERS

Where the problems with proving are encountered, or where it can be shown that flow rates on the installation concerned have declined to the extent that the existing prover is now over-sized, the MoO may be prepared to consider meter proving by use of a suitable master meter.
The proposed master meter shall be appropriate for the nature of the fluids concerned.

Common-Mode Error

One of the arguments against the use of a master meter is the possibility of 'common-mode' errors. These may be caused by:

1) A change in the fluid's characteristics that affects equally the response of the 'duty' and the 'master' meter.
2) A long-term 'drift' in the response of both the 'duty' and 'master' meter caused by their continued use.

In order to guard against the first of these, it has until recently been thought to be a necessary condition that the master meter shall be based on a different operating principle from that of the meters being proved.
While this is perhaps still advisable, recent experience with helical-bladed turbine meters suggests that they may be sufficiently insensitive to changes in the process fluid to make the first of these sources of common-mode error unlikely.
In order to guard against the second source of common-mode error, the 'master' meter shall be by-passed and isolated when not in use so that any long-term drift would be detectable when the 'duty' meter is compared with the 'master' meter.

Note:
It is not required for the master meter to be permanently installed although in this location it may be advisable

Installation Considerations

A master meter installation shall include:

- Sufficient upstream filtering of the fluid to protect the master meter from damage.
- Sufficient uninterrupted straight lengths of pipe upstream of the master meter to ensure unbiased flow at the meter.
- Sufficient valving to allow the master meter to be removed for inspection and calibration without disturbing normal flow.
- A dedicated master meter flow computer capable of determining master meter flow, temperature, pressure, and density to a level of accuracy equal to that of the flow computer used with the meter being proved. Such a master meter flow computer shall ideally be programmed to control proving sequences and to calculate meter factors.

Recalibration of Master Meter

The master meter shall normally be recalibrated at intervals not exceeding 3 (three) months, or whenever its operation is thought to be suspect. The meter shall be calibrated as a complete working unit – combined spool and internals, along with any dedicated interface electronics as required.
The master meter shall be calibrated on the in-service fluid, where possible, across at least the range of flow rates commonly met in operation. Use of any other calibration fluid shall be discussed with the MoO well in advance. Alternative calibration fluids shall, if possible, be of the same viscosity range as the service fluids likely to be encountered during the master meter's service.
A spare calibrated master meter shall be held at the metering station, ready to be placed in service during periods when the other master meter is being calibrated or inspected.
The MoO may require to witness calibrations of master meters, and shall be given at least 21 days notice of such calibrations.

7.12 OPERATING & RE-VERIFICATION PROCEDURES – ULTRASONIC METERS

Initial Calibration

Meters shall under all circumstances be flow calibrated at a recognised laboratory prior to their use in service. This applies equally to master meters, where their use is proposed.
The meter shall be calibrated over as much of the full anticipated flow range as possible, with particular attention paid to the expected operating flow rate. The meter shall normally be calibrated at least six 'nominal' flow rates evenly-spaced within the range, with interpolation of the calibration offset for flow rates not directly covered. To maintain traceability, the calibration data and interpolation calculations shall be stored within the flow computer rather than the meter electronics.
While it is recognised that meters may have built-in viscosity correction features, the dependence on these factors shall be minimised by calibrating the meter on a fluid that resembles, as closely as possible, the in-service process fluid.
It is recognised that this may be a potential barrier to the use of ultrasonic meters for metering installations with high export flow rates, as suitable calibration facilities may not exist. There may be scope to use onshore terminal facilities as calibration sites. Metering stations equipped with turbine meter and prover loop designed for 'batch' export may be particularly suitable for this purpose.
In addition, the flow profile at the calibration shall be representative of that predicted at the 'in-service' meter conditions. If this condition cannot be met then the use of flow conditioners may be necessary.

In-Service Reverification

It is recognised that the inherent diagnostic features of ultrasonic meters are a potentially very powerful tool. These potentially offer the user the ability to extend the 'health care monitoring' strategy to the extent that either meter removal and recalibration, or an alternative in-situ reverification (such as meter proving) become unnecessary.
However, it has not been demonstrated to the MoO's satisfaction that there is sufficient quantitative information contained within the diagnostics for such a scenario to be acceptable. The information offered by the diagnostics is qualitative rather than quantitative, and as such cannot be relied upon to demonstrate that meter performance has changed by a pre-determined amount that would necessitate meter removal and recalibration.
Therefore, as indicated in Section 7, there shall be essentially 3 methods for reverification of ultrasonic meters. These are:

- The use of a master meter.
- Removal of the meter for calibration at a recognised test facility.
- Comparison of the meter with a pipe prover.

Master Meters

The 'duty' meter shall be compared with the 'master' meter at a frequency agreed with the MoO. This shall typically be weekly at first, with the possibility to extend the interval between successive calibrations subject to satisfactory meter performance.
Flow rate shall be integrated over an interval agreed with the MoO so that the 'flowed' volumes calculated by the two meters may be compared, taking account of the necessary volume correction factors. The extent of the calibration interval shall depend on the flow rates concerned, but shall typically be in the order of 1 hour.
To guard against the possible 'drift' of both 'master' and 'duty' meters, the master meter shall be periodically removed and calibrated at a recognised facility.
The interval between successive recalibrations of the master meter shall take place at intervals agreed with the MoO.

Meter Removal / Recalibration

The comments on the initial flow calibration, above apply equally to subsequent re-calibrations of the meter.
The interval between successive recalibrations shall be determined on a case-by-case basis following discussions, including the presentation of operating data between the Oil & Gas Operators and the MoO.

Proving

The use of pipe provers to calibrate ultrasonic meters has been tried in practice, but with limited success. Ultrasonic meters do not have the inherent inertia of turbine meters, with the result that instantaneous fluctuations in flow rate, which are to some extent 'damped' by turbine meters, are generally detected by their ultrasonic equivalents. As a result, repeatability may not be sufficient for meaningful comparisons to be made. This problem is even more pronounced with small volume provers.
There is considerable scope, however, for the use of statistical methods in interpreting the results from pipe provers (see, for example, *Folkestad*) although these have yet to be adopted in practice.

7.13 OPERATING & RE-VERIFICATION PROCEDURES–CORIOLIS METERS

Meter Calibration

The Coriolis meter shall be flow calibrated prior to installation.
Since the Coriolis meter is a direct mass meter, calibration against a similar mass flow rate standard is preferred. Where the Coriolis meter is calibrated against a volume flow rate

standard, the uncertainty in the density of the test fluid (at meter conditions) shall be considered when interpreting the calibration results.
The calibration conditions shall generally be as similar as practically possible to the anticipated 'in service' conditions.
This requirement does not extend to the upstream pipe configuration, since Coriolis meters are relatively insensitive to flow profile.
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Zero Flow Check

The following parameters:

- Stresses on the meter from the surrounding pipework
- Fluid and ambient temperature
- Fluid pressure
- Fluid density

may differ substantially from 'calibration' to 'installation'. The effect of each of these differences shall be a shift in the meter's output at zero flow.
Therefore, once the meter is installed, the net impact of these installation effects shall be quantified by performing a zero-flow check.
To check or adjust the zero-flow output, the meter shall be 'full' and all flow stopped.
Zero adjustment, if necessary, shall only be made under process conditions of fluid temperature, pressure and density.

Meter Reverification

The meter may be reverified by

- Periodic comparison with a prover
- Removal and recalibration at a recognised test facility

7.14 PRE-CONDITIONS FOR 2-YEARLY PROVER CALIBRATION

The MoO may consider the case for extending to 2 years the interval between successive recalibrations of a prover provided that the following conditions are met:

1. The nominal production rate through the meters routinely calibrated by the prover shall not exceed 50,000 barrels/day.
2. Considering the 5 most recent prover calibrations, for each prover volume to be used:
3. The calibrated volume has remained within a range of ±0.02% of its mean.
4. The shift between the 1st and the 5th prover calibrations is no greater than ±0.02%.

Oil & Gas Operators wishing to pursue the possibility of 2-yearly prover calibration, and whose systems meet the above criteria, shall contact the MoO in order that the matter may be discussed more fully.

7.15 PROVER RECALIBRATION – A GUIDE FOR OIL & GAS OPERATORS

To ensure that the process of prover recalibration proceeds as smoothly as possible, Oil & Gas Operators shall take account of the following guidance.
The calibration of the prover shall normally be carried out by an independent third party, referred to here as the 'Calibrating Authority'.

Prior to the Prover Calibration

Prior to arrival of the calibration rig:

1. The Oil & Gas Operators shall appoint a member of site personnel to liaise with the Calibrating Authority's calibration engineer.

2. Site management responsible for production shall when possible plan the prover calibration work so that it fits into a period of stable process conditions.
(This does not apply when the calibration takes place using fluids other than the process fluids as the calibration medium)

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

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

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

6. The installation Management shall ensure that all relevant site staff have been briefed in advance of their roles and responsibilities so that disruption during the proving process is minimised.

7. Immediately in advance of the arrival of the calibration rig, the Oil & Gas Operators shall ensure that:
- The prover's 4-way valve is not leaking.
- All relevant isolation valves are leak free, and a means of testing or proving their integrity established.
- All relevant thermowells have been cleaned out and filled with thermally-conducting oil.

8. As a minimum, the following spares shall be held:
- 4-way valve slips
- Prover door seals
- One complete set of prover detector switches; these shall have been checked for correct operation and for correct insertion depth.
- Prover sphere valves.

9. The Oil & Gas Operators shall check that a spare prover sphere of the correct size, material, and condition is available, as well as all necessary sphere tools and a sphere pump. A readily available supply of glycol shall also be provided.

10. The Oil & Gas Operators shall contact the Calibration Authority to determine which specific site services are necessary, and then ensure that that these are provided. For example, the provision of the following may need to be considered:
- Power supplies (440Vac, 240Vac or 110Vac) with suitable connections.
- Potable water for flushing the master prover at the end of the calibration.
- Dry white spot nitrogen at 1000 psi.

11. The Oil & Gas Operators shall have available a suitable pump for hydro-testing or leak-testing the hook-up of the site prover to the calibration rig.

During the Prover Calibration

12 During prover calibration, the Oil & Gas Operators shall strive to maintain, as far as possible, steady flow through the metering station, and remain attentive to the requirements of the calibration, as determined by the Calibration authority's engineers.

13 The decision as to whether or not the calibration has been completed satisfactorily ultimately rests with the MoO. However, the accredited Calibrating Authority shall normally be competent to decide whether or not the relevant criteria have been met.

After the Prover Calibration

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

15 Once the master prover has been put back in its container, the Oil & Gas Operators shall make every effort to ensure that the master prover container is removed from site as soon as possible, in order not to create any 'knock-on' delays at the site of the next prover calibration.

7.16 REFERENCES / TECHNICAL PAPERS

FOLKESTAD, T. Testing a 12" Krohne 5-path Altosonic V Ultrasonic Liquid Flow meter on Oseberg Crude Oil and on Heavy Crude Oil. North Sea Flow Measurement Workshop, Kristiansand, Norway 2001.

COUSINS.T, AUGENSTEIN.D Proving of Multipath Liquid Ultrasonic Flow Meters. North Sea Flow Measurement Workshop, St Andrews, Scotland 2002.

7.17 GASEOUS PETROLEUM MEASUREMENT "TERMS OF REFERENCE"

These notes are intended to provide the Oil & Gas Operators with guidance on high-quality flow measurement of petroleum in the gaseous phase.

This section of the MoO measurement code is intended for use exclusively with single-phase gas. Where liquids or other contaminants are thought to be present, Oil & Gas Operators are strongly advised to exercise caution in applying the principles and advice provided here.

This section deals with Custody-Transfer standard gas flow measurement. By industry consensus, this is defined as flow measurement with an overall uncertainty of ±1.0% or better. The overall uncertainty is derived from an appropriate statistical combination of the component uncertainties in the measurement system.

Primary Measurement Device

The equipment used to achieve this level of performance shall vary according to the particular circumstances of each facility. Almost all of the gas metering stations covered by this measurement code make use of either orifice plate or ultrasonic meters. These notes deal principally with these two types of system.

Coriolis meters are beginning to be accepted for Fiscal / Custody Transfer gas applications, but there is relatively little experience in this area. The MoO is of course open to proposals for their use.

Whichever method of measurement is adopted, there are certain common principles that shall be adhered to; these are covered in the following sections of this code.

7.18 MODE OF MEASUREMENT

Volume or Mass Units

All measurement shall be made on single-phase gas streams.

Hydrocarbon measurements may be in either volumetric or mass units. The choice of measurement shall however be agreed with the MoO..

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

Sampling

Suitable facilities shall be provided for the purpose of obtaining representative samples. The type of instrumentation incorporated within the measuring system may influence this specific requirement.

Gas Density

Gas density at the meter may be determined either by:

a) *continuous direct measurement*, by on-line densitometer

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

Both methods may be used simultaneously, and the comparison of their respective results may provide additional confidence in the accuracy of each method. This method is discussed in more detail below.

Where measurement is reported in volume, the continuous determination of gas relative density and hence density at standard reference conditions is preferred. However, the standard reference density of the gas being metered may, under certain circumstances, be calculated using a recognised equation of state together with measurements of the gas temperature, pressure and composition.

7.19 DESIGN & INSTALLATION CRITERIA FOR GAS METER STATIONS

Avoidance of Liquid Carry-Over

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

Secondary Instrumentation

Secondary instrumentation shall generally be required for the measurement and recording of the following parameters:

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

The position of the instrumentation within the system shall be such that, as far as possible, representative measurement is ensured.

Consideration shall be given during the design of a measurement system for the provision of back-up instrumentation to cover the failure of normal instrumentation, and also for the provision of suitable facilities for the on-site verification of secondary metering equipment.

Density Measurement

Gas density is normally measured in a ‘by-pass’ line to avoid introducing flow profile disturbances. Useful guidance on correct design is provided by the IP Petroleum Measurement Manual, Part VII (‘Density’).

It is important that the gas entering the densitometer is representative of the gas in the line, in respect of composition, temperature, and pressure. This becomes critically important if, as is generally the case, the pressure and temperature are not measured directly at the densitometer. In the MoO’s experience, failure to take account of this factor in the design of densitometer installations is one of the principal causes of significant mismeasurement in ‘real’ applications.

Oil & Gas Operators may therefore consider the use of densitometers fitted with temperature elements, although the reverification of these temperature elements may itself be problematic. No standard facility presently exists to measure temperature directly at the densitometer.
Therefore, unless the temperature is measured directly at the densitometer, installations *shall* be designed to so that

- The effect of ambient conditions (normally a cooling one) on the temperature of the gas sample is minimised. This may mean keeping the densitometer inlet line in close thermal contact with the meter tube; ideally it shall be placed under any lagging. In extreme cases it may be necessary to heat-trace the line; in this case care shall be taken not to over-heat the sample.
- There is no pressure drop between the densitometer and the point in the system where pressure is normally measured. Therefore all isolation valves between the densitometer and the pressure measurement point shall be of the full-bore type.

In systems where gas density is also calculated, the comparison of the 'measured' and 'calculated' values shall provide a valuable means of demonstrating confidence in the measured value..
Densitometer installations shall be designed so that, as well as meeting the above criteria, they also offer the facility for easy and efficient removal of densitometers and, preferably, the facility to readily view their Serial Numbers for auditing purposes.

Gas Chromatographs

Where it is planned to use gas chromatographs, these shall be installed at 'high-points' in the system whenever possible, in order to reduce the probability of liquid contamination.
The distance of the chromatograph from sample take-off points (from both the meter streams and the calibration cylinders) shall be minimised. Sample lines shall be lagged and heat traced to maintain the temperature of the gas above its dew-point.
A low temperature shut-off valve shall be installed on the sample inlet to the pressure let-down system to prevent any liquid drop-out being transmitted to the gas chromatograph.
Calibration gas cylinders shall be prepared by recognised laboratories following procedures accredited by UKAS or equivalent overseas accreditation bodies.
These cylinders shall be maintained at a temperature above the 'minimum storage temperature' stated on their calibration certificates. Either the cylinders shall be stored in a heated enclosure, or the mixtures shall be certified to have a dew point of -10ºC or lower.
When a cylinder has been stored at temperatures below this minimum temperature (for example, during transportation offshore) it shall be 'heated' prior to its use in order to homogenise, as far as possible, the cylinder contents. If this is not done, or if the cylinder is used while stored below its minimum temperature, it is likely that the lighter components may be preferentially sampled during chromatograph calibration. This effectively invalidates the calibration gas cylinder's certification.
Pressure let-down systems for use with gas chromatographs shall, under normal circumstances, be designed so that the ratio of absolute pressures across each pressure reduction stage is constant.
With the possible exception of the final stage let-down valve, pressure let-down valves shall be heated to prevent any liquid drop-out caused by Joule-Thompson cooling of the gas as it expands. In practice this normally means that valves shall be 'hot to the touch'.

Flow computers and/or databases shall be set with alarm limits on each of the components downloaded from the gas chromatograph in order to prevent the acceptance of a spurious composition in the event of system failure.

Choice of Primary Measurement Device

Where metering systems other than orifice plate or ultrasonic metering are to be deployed, these systems together with their flow compensating devices (if applicable) shall be of the types agreed by the MoO.

If it is proposed to use new technology then details of the proposed equipment, layout and verification procedures shall be discussed with the MoO at the earliest opportunity.

Consistency within Systems

In a gas gathering system, the Oil & Gas Operators shall ensure that the basic metering data, flow formulae and computational techniques are compatible throughout all the facilities connected to the gathering system. Independent validation of the calculations shall be performed.

Requirement for Notification of MoO

The MoO shall require adequate notice (normally at least 21 days – depending on the location this may need to be extended) 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.

7.20 DESIGN & INSTALLATION CRITERIA FOR ORIFICE METER SYSTEMS

Application of ISO 5167 or API 14.3

For new measurement systems the design, installation and operation shall normally be expected to comply with the principles of ISO 5167. Any proposed departure from the most recent revision of this ISO standard shall be discussed with the MoO prior to implementation.

For existing metering systems, proposals to implement new or modified requirements contained within the current revision of ISO 5167, either partially or in full, shall be discussed with the MoO prior to implementation.

Discharge Coefficient Equation

In 1998 the Reader-Harris/Gallagher equation replaced the Stoltz equation for the determination of orifice plate discharge coefficient in ISO 5167. The effect of this change, for typical applications, is that the reported mass flow is decreased by a systematic factor in the region of 0.1-0.2%.

It is of course desirable in principle that the latest version of the discharge coefficient equation shall be used wherever possible. However, the following points shall be considered:

a) Where there is more than one entrant to a pipeline allocation system using exclusively orifice plate measurement systems, uniformity in the use of discharge coefficient equation at pipeline entry points is paramount, in order to avoid the introduction of a systematic bias. This consideration over-rides the desire to use the latest version of the discharge coefficient equation.

b) Terminal measurement systems shall wherever possible use the latest version of the discharge coefficient equation, as no systematic bias is introduced as a result.

For allocation systems involving ultrasonic meters as well as orifice plates, the use of the Reader-Harris/Gallagher equation is preferred for all new developments, as these are more likely to be consistent with the ultrasonic meter measurements. Every opportunity shall be made to upgrade older orifice plate systems from the Stoltz equation to the Reader-Harris/Gallagher equation.

Design Considerations

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

a) Maximum Reynolds number shall not exceed 3.3×10^7
b) The total deformation including static and elastic deformation of the orifice plate at maximum differential pressure shall be less than 1%
c) The uncertainty in flow measurement caused by the total deformation of the orifice plate shall be less than 0.1%
d) The location of the differential pressure tappings with respect to the orifice plate shall remain within the tolerances given in ISO 5167 over the full operating ranges of the differential pressure transmitters. Where plate carriers utilise resilient seals, care shall be taken to ensure that the load on the plate caused by the maximum differential pressure does not move the plate out of the pressure tapping tolerance
e) If the maximum differential pressure across the orifice exceeds 500mbar bar, it shall be demonstrated that the conditions of b), c) and d) are met
The latest version of ISO 5167 provides increased scope for the use of ß-ratios higher than 0.6. Higher ß-ratios may be used, provided the overall uncertainty remains below 1.0%.

Meter Runs

Sufficient meter runs shall be provided to ensure that, at the maximum design production rate of the facility, at least one stand-by meter is available.
The Oil & Gas Operators shall normally be expected to provide an adequate level of isolation valving so that individual orifice plates and runs may be removed from service without the need to shut down the entire metering or process system. Such requirements may, under certain circumstances, be waived if suitable alternative fallback options are formulated and agreed in advance with the MoO.

Flow Pulsations

The orifice metering station shall be located such that pulsations in the flowing gas are avoided. Where these are unavoidable, the uncertainty in flow due to any such effects shall be kept below 0.1%.
Useful guidance in such situations may be found in ISO Technical Report 3313.

Upstream and Downstream Pipework

The metering station shall be positioned within a process facility such that the effects of fittings and pipework, both upstream and downstream of the orifice meters, do not impact on the minimum straight length requirements given in ISO 5167.
If flow conditioners are proposed as part of the design, the type and location of these devices shall be discussed with MoO. In addition, provision shall be made to periodically inspect these devices, ideally in situ.

7.21 DESIGN & INSTALLATION CRITERIA ULTRASONIC METER SYSTEMS

For Fiscal / Custody Transfer USM standard applications, only transit time multi-path ultrasonic meters shall be used.

Application of Standards

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

Meter Redundancy

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

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

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

Isolation Valving

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

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

Meter Diagnostics

Multi-path ultrasonic flow meters incorporate a variety of diagnostic tools that are either individually or collectively be employed for 'health care' monitoring. The use of data acquisition features that permit this information to be logged (and perhaps accessed remotely in real time) is strongly recommended, as it may eventually be possible to use this information to justify an extension to the interval between meter recalibrations. Section 4.6 provides further Guidance in this area.

Presence of CO2

The presence in high levels of some components, such as CO2, in the gas can influence and possibly even inhibit the operation of the meter. The Manufacturer shall be consulted on this issue if CO2 levels are expected to approach 8% or if the meter is operating near the critical gas density.

Upstream and Downstream Pipework

When assessing the potential impact of pipe geometry on the performance of the meter, the manufacturer shall be consulted and the following factors considered:

- The general configuration of the pipework and fittings upstream and downstream of the metering system.
- The presence of any self-compensating features associated with the ultrasonic meter.

The metering station shall not be installed where vibration or noise levels can interfere with the performance of the meter. In particular, ultrasonic noise from the so-called 'quiet' control valves can interfere with the operation of ultrasonic meters, as can the close proximity of pressure reduction devices.

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

The step between the ultrasonic meter and the upstream spool shall meet the requirements of both 'in-service' and at the calibration facility.

If flow conditioners are proposed as part of the system design then the type and location of these devices shall be discussed with the meter manufacturer prior to installation. In particular, care shall be taken to ensure that these devices do not generate ultrasonic noise or interact with

self-compensating features built into some types of meter. If flow conditioners are installed then provision shall be made to periodically inspect these devices, ideally in situ.

Density Measurement

Due to their linear, rather than square-root, relationship with density, flow rates determined using ultrasonic meters are more sensitive to density error than those based on orifice plate meters. Special care shall therefore be taken to ensure the location of secondary instrumentation is both representative and accurate. This is particularly important when density is calculated.

7.22 OPERATING & RE-CERTIFICATION PROCEDURES FOR FISCAL / CUSTODY TRANSFER GAS METERING STATIONS

Isolation of Secondary Instrumentation

Secondary instrumentation, which may be susceptible to damage or malfunction if exposed to foreign matter, shall be isolated from the process for the first 24 to 48 hours after start-up. Instruments most likely to be affected are densitometers, relative density analysers and gas chromatographs. During this period the flow computers shall preferably use a default gas composition to calculate the gas density at operating and reference conditions or where appropriate, ‘keypad’ values may be manually entered. The computer shall be returned to ‘live input’ density (line and standard reference) as soon as the process clean-up is complete.

Recalibration of Secondary Instrumentation

Detailed procedures for the verification of secondary instrumentation, such as that used to monitor and record differential pressure, pressure, temperature, gas composition, density and relative density shall be prepared for review by the MoO.
The re-calibration frequency for each component in the measurement system (primary and secondary instrumentation) shall be included within the recertification procedure document. Initially, the re-certification frequency for most components shall be monthly. As a history of equipment stability is built up it may be appropriate to increase the intervals between recalibrations. Prior permission to relax these calibration frequencies shall be sought from the MoO. In order to support such an application it shall be necessary to show that the instruments remain within tolerance on a number of successive re-calibrations and are returned to service in the ‘as found’ condition.

Test equipment used for the calibration of secondary instrumentation shall be calibrated following procedures by an Internationally accredited body such as UKAS (or an equivalent overseas body) whenever possible.
This test equipment shall be dedicated to the metering systems and shall be stored securely.

The tolerances used when re-calibrating secondary instrumentation shall be set at a level which, while not being so tight as to make their achievement under field conditions extremely difficult, shall not be so lax as to risk compromising the overall target uncertainty of the measurement system.
The MoO may consider a re-calibration 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 shall be supplied if an Oil & Gas Operators wishes to adopt such procedures. This shall include an analysis of the impact such procedures would have on the overall uncertainty of the metering system.
Where other methods of measurement are employed such as turbine meters or PD meters, either singly or in combination, the appropriate operating procedure and also procedures for periodic verification shall be discussed at the design stage with the MoO.

Use of 'Calculated' Gas Density

When density is calculated, 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 weight	1%	1.6

Measured/Calculated Gas Density Discrepancy

In view of the absence of any possible 'common-mode' error, where both 'measured' and 'calculated' density is in place, the discrepancy between these parameters shall be monitored continuously as a means of demonstrating the reliability of each measurement.
The system shall incorporate an 'alarm limit' to highlight the occurrence of a higher-than-normal discrepancy. This alarm limit shall not normally exceed 2% of the value of the density being measured.
In the MoO's experience, gas density discrepancy is more often caused by error in the 'measured' quantity. Provided that the reliability of the 'calculated' density has been demonstrated, the system shall be set up so that the 'calculated' mode becomes the primary measurement whenever this alarm limit is exceeded.

Gas Chromatographs

Gas chromatographs used in high-quality gas measurement applications normally feature a 'self-calibration' facility.
Calibration reports shall feature a value for the 'un-normalised' component total. This value shall be monitored, as it demonstrates the reliability of the chromatograph's 'response factors'. Under normal circumstances, it shall lie within the range 100 ± 2%. For 'sales gas' measurement stations this tolerance shall normally be tighter – typically 100 ± 1%.

7.23 OPERATING & REVERIFICATION PROCEDURES – ORIFICE METERING

Pre-Commissioning

The Oil & Gas Operators shall prepare a schedule of pre-commissioning tests to demonstrate the operability of salient aspects of the flow measurement metrology as detailed within ISO 5167. In particular, the interior of the meter tubes and of the orifice bores shall be examined to ensure they conform to the relevant provisions of the Standard.

Start-up Plates

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

Inspection of Orifice Plates and Meter Tubes

The interval between successive orifice plate inspections shall initially be one month.
Once it has been established that plate contamination is not likely, this interval may be extended after consultation with the MoO. A typical inspection sequence, assuming that the condition of the plates is satisfactory on each occasion, might be:

- 6 plate inspections at 1-month intervals.
- 2 plate inspections at 3-month intervals.
- 2 plate inspections at 6-monthly intervals.
- Annual plate inspection.

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

When carrying out an examination of an orifice plate in the field it is not necessary to conduct a full gauging examination to the provisions of ISO 5167 [30]. The main points of focus for an orifice plate field inspection are:

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

ISO 5167 allows an edge roughness of up to 0.0004d (where d is the orifice diameter).
However, ISO TR 15377 indicates that there is a more or less linear relationship between edge roughness and overestimation of discharge coefficient, Cd. On the tolerance limit (0.0004d), systematic overestimation of Cd by 0.1% can be expected.
The cost involved in re-machining the straight edge is likely to be insignificant compared with the costs involved in systematic mismeasurement of mass flow rate by up to –0.1%. Therefore if any damage to the upstream straight edge has occurred, it shall always be re-machined prior to re-use.

It may be necessary from time to time to examine the condition of the meter tubes, to ensure that corrosion, erosion or contamination has not occurred to an extent likely to affect the accuracy of the meter. These examinations may be necessary if periodic plate inspections show persistent contamination. Particular attention shall be paid to the bore of the pipe section extending 2 pipe-diameters upstream of the orifice plate and also to the condition of the upstream and downstream pressure tappings at their respective points of breakthrough into the meter tube wall. If flow conditioners are used, these shall also be examined for contamination and any obvious surface damage at the same frequency as the orifice plates are themselves inspected.
It is recommended that boroscopes are used for inspection purposes, and video recording facility shall be utilised where possible in order to provide a traceable record of the inspection.

Differential Pressure Measurement

For metering stations, differential pressure transmitters shall be calibrated at high static pressure representative of the normal operating pressure for the instrument.
An exception can be made where measurement is for ‘allocation’ rather than ‘sales’ purposes, where the use of ‘footprinted’ transmitters may be permissible.

For metering stations, high static calibrations shall be performed at a suitable calibration facility and subsequently ‘footprinted’ at atmospheric pressure for use in periodic verifications. The high-static pressure shall be representative of that likely to be encountered under normal operating conditions.
Recent years have seen significant advances in differential pressure measurement and calibration techniques. Consequently, in the event of a differential pressure cell failing its ‘footprint’ check, once liquid contamination, adverse pressure shocks etc. have been ruled out as possible reasons for the failure, adjustment at zero static pressure may now be considered. The following conditions apply:

a) The static shift exhibited by the differential pressure cell at its onshore calibration is less than 0.05% per 100 bar.
b) The differential pressure transmitter has a proven history of static shift stability, i.e. at least two successive ‘footprints’ demonstrating compliance with the criteria.
c) The differential pressure transmitter damping factor is less than ≈1s (this gives a ≈5s response time to a step-change in differential pressure).
d) The uncertainty of the calibration standard is an order of magnitude lower than the operating tolerance of the transmitter under calibration.

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

If an Oil & Gas Operators wishes to pursue this strategy, supporting data shall be made available to the MoO, who may then agree to the atmospheric calibration of differential pressure transmitters on an instrument-by-instrument basis.

In order to guard against long-term drift of the differential pressure transmitter, it shall be returned for calibration after 12 months in service, irrespective of its performance in periodic reverification.

Differential pressure transmitters used in offshore applications shall be introduced into service no more than 12 months after the date of their onshore calibration. Their period in service shall then not exceed 12 months.

Densitometer Recalibration

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

7.24 OPERATING & REVERIFICATION PROCEDURES ULTRASONIC METERS

Recalibration Strategy

It is now approximately 7 years since multi-path ultrasonic meters first became generally accepted as being suitable for use in Custody-Transfer applications in the upstream sector. Throughout this period it has been the policy of both the MoO and commercial pipeline regulators to insist on the periodic removal of the meters for calibration at a recognised test facility. The period between recalibrations varies from application to application, generally depending on calibration history and meter throughput, but as a rule it ranges from 12 months to six years.

Multi-path ultrasonic meters offer a number of inherent diagnostic capabilities that can be used to give at least a qualitative indication that the meter has not shown any drift in its operating characteristic.

Shall these self-diagnostic facilities become sufficiently well understood, it may be possible to extend the interval between meter calibrations beyond the current 12 month horizon; it may even ultimately be possible to abandon the strategy of removal and recalibration altogether, in favour of a continuous ‘health-checking’ regime. This is in fact the ultimate goal of the MoO, Oil & Gas Operators and meter manufacturers.

A ‘health-checking’ regime, as permitted by currently-available technology, offers the following advantages relative to a ‘removal and recalibration’ strategy:

a) Operating costs may be reduced.
b) Shifts in meter performance could potentially be detected (at least qualitatively) when they occur, rather than at the next meter calibration.
c) Shift in meter characteristic caused by physical shock during removal and transport to and from the calibration facility would be prevented.
d) The introduction of a systematic shift due to faulty procedures at the recalibration facility (for example, failure to install a flow conditioner) would be prevented.

However, it also has the following disadvantages:

e) The diagnostic facilities are presently qualitative, rather than quantitative
f) The Oil & Gas Operators could be exposed to mismeasurement for longer than 12 months, unless the source of measurement was detectable by the meter diagnostics.

The meter diagnostics may indicate that a shift in meter characteristic has occurred. However, it has not been demonstrated to the MoO’s satisfaction that the level of shift in meter diagnostics can be related quantitatively to a shift in meter performance. It is therefore currently impossible

to determine whether a pre-defined ‘trigger level’ of meter shift, necessitating meter removal and recalibration, has occurred.

Consequently, the requirement to remove and recalibrate ultrasonic meters remains in place.

The disadvantages referred to can to some extent be mitigated by the adoption of a ‘combined’ strategy. For example, very significant change in meter diagnostics (an extreme example of which is chord failure) can be taken as an indication that meter removal is necessary; these may occur in the normal course of the meter’s service or they may be evidence that the meter has been ‘shocked’ in some way between the recalibration facility and the metering station. Sources of systematic shift from recalibration facilities are now better understood and can be minimised or eliminated altogether by the adoption of the practices referred to below.

Flow Profile

The Oil & Gas Operator shall ensure that the flow profile during meter calibrations matches, as far as possible, the predicted ‘in-service’ flow profile.
If the meter is to be installed with a flow conditioner, it shall be calibrated with the same design of flow conditioner, in the same orientation and position within the meter run. Upstream meter run pipe shall be included in the flow calibration loop along with flow conditioner and meter.

Initial Flow Calibration

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

Recalibration of Ultrasonic Meters

The MoO Department currently requires ultrasonic meters to be periodically removed and recalibrated. The recalibration, in common with the initial flow calibration, shall take place at a recognised, accredited, test facility.
The MoO recognises that there have been cases of unexplained systematic offsets between some of the principal European calibration facilities; the recent ‘harmonisation’ between facilities in Germany and the Netherlands may be cited as an example.
In order to minimise the cumulative effect of any such systematic bias, the MoO therefore advises Oil & Gas Operators to return meters to the same facility throughout the meters’ life in service.
Intervals between successive calibrations shall be agreed with the MoO on a case-by-case basis. In common with the MoO’s approach in other areas, the economics of the particular field development shall be taken into account when assessing the appropriate recalibration period.
When determining the intervals between successive recalibrations, the MoO may also consider the availability and relevance of ‘health-check’ procedures that utilise the diagnostic facilities available via the ultrasonic meter electronics..

The meter shall preferably be calibrated on a representative fluid, although recent work (Hall) suggests that the results of a meter calibration on, for example, air or nitrogen is transferable to a natural gas application.
Recent work (Hall) suggests that there is no significant ‘pressure effect’ for ultrasonic meters, i.e. the meter may be calibrated at one pressure and operated at another with no significant shift in meter response as a result. However, until this is proved definitively, it does make sense to calibrate meters at conditions as close as possible the anticipated operating conditions.
Meters shall normally be calibrated in their ‘as found’ state so that any shift in meter performance from the previous calibration can be quantified.
Experience with ultrasonic meters over the past 7 years has shown that meters are likely to show the greatest shifts in the first 6 months of operation. It appears that the meter bore become ‘conditioned’ in-service during this period. Cleaning of the meter bore may therefore be counter-productive and is not recommended.

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

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

Oil & Gas Operators shall retain this information for each meter (preferably in a dedicated dossier). The relevant information shall be available for inspection at all times.
Industry standard practice at present (May 2003) is for at least 3 runs to be performed at least 6 different flow rates, spaced more or less evenly between the minimum and maximum design flow rates for the meter.
Statistical interpretation of any data from ultrasonic meter calibrations shall take into account the number of test runs at each flow rate. Following the principle of the '1/√N' law, the calibration uncertainty reduces with an increasing number of test runs (provided of course, that the test flow rate remains constant).
It is recognised that the practical possibility of increasing the number of test runs at each flow rate may be subject to financial and/or time constraints. Oil & Gas Operators may therefore wish to consider whether increased attention shall be paid to the expected operational flow rate, if necessary at the expense of other, less 'representative' flow rates. Such an approach has the potential to reduce the meter's operational uncertainty.
Replacement of the ultrasonic meter transducers/detectors or electronics shall normally necessitate recalibration of the meter, unless the effect of these actions has been quantitatively determined at the meter calibration and found to be insignificant.
Oil & Gas Operators may wish to consider this requirement when planning recalibration strategy. Time thus spent at the meter recalibration may prove to have been well spent shall any critical components fail in service.

Implementation of Calibration Data

Correction routines employed to compensate for process and environmental effects on the performance of the meter shall, as far as possible, be undertaken within the flow computer and not the USM electronics. Similarly, routines adopted to generate instantaneous flow rate corrections based on multi-point calibration data shall also be performed within the flow computer.
The preferred option is point-to-point linear interpolation. A single point flow-weighted average may be applied if all calibration points lie within ±0.1% of their average value.

Inspection of Meter Spool and Associated Pipework

It may be necessary from time to time to examine the condition of the meter spool and associated straight pipe sections, to ensure that corrosion, erosion or particulate contamination has not occurred to an extent likely to affect the accuracy of the meter. Particular attention shall be paid to the bore of the meter and the transducer/detector ports and, where appropriate, the condition of the pressure tapping at the point of breakthrough into the meter wall. If flow conditioners are used, these shall also be examined for contamination and any obvious surface damage.

Reference Standards

Adequate verification or, where appropriate, calibration equipment shall be provided to enable the performance of meters, transducers, computers, totalisers, etc. to be assessed. Reference or transfer standards shall be certified by a laboratory with recognised traceability to National or International Standards.

Minimum Operating Pressure

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

7.25 CALCULATION OF UNCERTAINTIES IN FLOW MEASUREMENT SYSTEMS EMPLOYING ORIFICE PLATE METERS ISO 5167 & ULTRASONIC METERS BS 7965

Orifice Metering Stations

For an orifice metering station, the uncertainty in the measurement of a mass flow rate shall be calculated using the simplified formula presented in ISO 5167. ISO 5168 offers further guidance in this area.

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 operational turndown of the system and also on the setting of the change over point(s) for metering systems incorporating both high and low range transmitters.

Ultrasonic Metering Stations

For an ultrasonic metering station, the uncertainty in the measurement of a mass flow rate may be calculated using the method presented in Annex A of BS 7965.

Alternative methods may be employed for the determination of uncertainty budgets for the measurement of mass flow rate; the choice shall however be discussed with the MoO prior to implementation.

Uncertainties of Secondary Instrumentation

When calculating the overall uncertainty budgets for metering installations, Oil & Gas Operators shall use realistic ‘field’ values for the uncertainties of the secondary instrumentation rather than the Manufacturers’ claimed values. The uncertainties claimed by Manufacturers for their equipment is usually the best that the equipment is able to deliver under ideal conditions.

Monte Carlo Simulation

Uncertainty calculations using Monte Carlo Simulation can be used as an alternative. Further Guidance in this area shall be published shortly.

8.0 MEASUREMENT MANAGEMENT SYSTEM ANALYSIS & IMPROVEMENT

8.1 GENERAL

This section focuses on identifying roles and responsibilities together with measurement procedures that shall lead to implementing a successful measurement management system analysis and improvement that conforms to the International Standard ISO 10012.

Measurement policy

MoO requires the Operating company to have an internal measurement policy statement regarding procedures /guidelines document pertaining to the (containing) the following as a minimum.

- Compliance with legal requirements, laws regulations by Governmental organisations (MoO)
- Operating company policies and procedures
- Fiscal / Custody Transfer for quantity and quality measurement standards

Measurement Manual

- Compliance with measurement manual procedures
- Witnessing of measurements test and calibrations
- Safety
- Record keeping
- Security

8.2 AUDITING & MONITORING

To ensure suitability and effectiveness of the measurement code the MoO shall use auditing, monitoring and other techniques, as appropriate, to determine the suitability and effectiveness of the measurement code.

This measurement system shall be continually improved through means of audits carried out in the following order of priority by.

1. MoO
2. Oil & Gas Operators (Internal audit mandatory)
3. *3rd party (optional)

* On request of the MoO a 3rd party accredited external auditing measurement Service Company shall be used to carry out some of the following typical activities.

- Metering audits
- Witness / Calibrating a prover
- Gas meter Calibrations,
- Gas / liquid sampling and lab analysis,
- Witness / Proving of liquid meters.

The MoO shall be informed of all measurement audit reports. Failure to comply with any of the requirements contained in this measurement code shall result in the following actions taken by the MoO:

1. An official warning
2. Grace period
3. Escalating fines
4. Withdrawal of operating licence

8.3 MEASUREMENT MANAGEMENT SYSTEM AUDIT

The MoO shall plan and conduct audits carried out by third party personnel to ensure that the measurement code implementation and compliance with the specified requirements is being carried out. Audit results shall be reported to affected parties within the organization's management.

The results of all audits of the measurement management system, and all changes to the system, shall be recorded. The MoO shall ensure that actions are taken without undue delay to eliminate detected nonconformities and their causes.

8.4 CONTROL OF NON-CONFORMITIES

Nonconforming measurement management systems

The MoO shall ensure the detection of any non-conformities, and shall take immediate action.

Interim actions (e.g. workaround plans) may be used until the corrective actions have been implemented

Nonconforming measurement processes

Any measurement process known to give, or suspected of producing incorrect measurement results shall be suitably identified and shall not be used until appropriate actions have been taken.

Nonconforming measuring equipment

The following list shall be considered applicable to measuring equipment that is considered as non-conforming:

- Damaged or overloaded
- Malfunction in such a way that may invalidate its intended use,
- Produce incorrect measurement results,
- Certification validity expires
- Damaged or broken seal or safeguard,
- Exposed to influencing quantities that can adversely affect its intended use (e.g. electromagnetic field, dust, heat),

8.5 IMPROVEMENT

Continual improvement system shall be based on the results of the audits, management reviews.

Corrective action

The criteria for taking corrective action shall be documented

Preventative action

- To eliminate the causes of potential measurement or confirmation nonconformities in order to prevent their occurrence.
- A documented procedure shall be established to define requirements.

9.0 APPENDIX - TYPICAL APPLICATIONS MEASUREMENT SYSTEMS

Typical applications for Fiscal / Custody Transfer and Allocation measurement systems for Crude Oil, Natural Gas and Hydrocarbon products have been described in this section.

UNCERTAINTY

The uncertainty levels referred to in Appendices 9.1 to 9.9 are for general guidance on expected quantity measurement performance only. This shall in no way indicate a specification of the required performance of measurement systems, which shall be subject to consideration to any legislation requirements for quantity and quality on a case-by-case basis including the use of uncertainty analysis / calculations.

9.1 Crude Oil - Fiscal Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Oil measurement with impact on state income, e.g. tax or royalty or sales at export stations.	Turbine, PD meter, Coriolis, Ultra-Sonic	±0.25%	Oil Density BS&W Sulphur Pour Point Salt	Meter Prover - Each loading (tanks) or weekly (pipeline) Density - Quarterly Flow Proportional Sampling - Annually Laboratory Equipment - Annually Pressure/Temperature equipment - Quarterly

9.2 Crude Oil - Custody Transfer Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Oil export terminal, Pipeline export, Transfer between companies, e.g. from producer to refinery	Turbine, PD meter, Coriolis, Ultra-Sonic	±0.25%	Oil Density BS&W Sulphur Pour Point Salt	Meter Prover - Each loading (tanks) or weekly (pipeline) Density - Quarterly Flow Proportional Sampling - Annually Laboratory Equipment - Annually Pressure/Temperature equipment - Quarterly

9.3 Crude Oil - Allocation Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Sharing pipelines or facilities between different companies.	Turbine, Coriolis, Ultra-Sonic, Orifice, PD meter	±0.50 - 2.00%	Oil Density BS&W	Meter Prover - Each loading (tanks) or weekly (pipeline) Density - Quarterly

9.4 Natural Gas - Fiscal Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Gas measurement with tax/royalty impact.	Turbine, Ultra-Sonic, Orifice,	±1.00%	Gas - Chromatograph Relative Density Hydrocarbon dew-point	Meter – monthly DP, Press & temp. transmitters - monthly

9.5 Natural Gas-Custody Transfer Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Gas transfer between different companies	Turbine, Ultra-Sonic, Orifice	±1.00%	Gas - Chromatograph Relative Density Hydrocarbon dew-point	Meter – monthly DP, Press & temp. transmitters - monthly

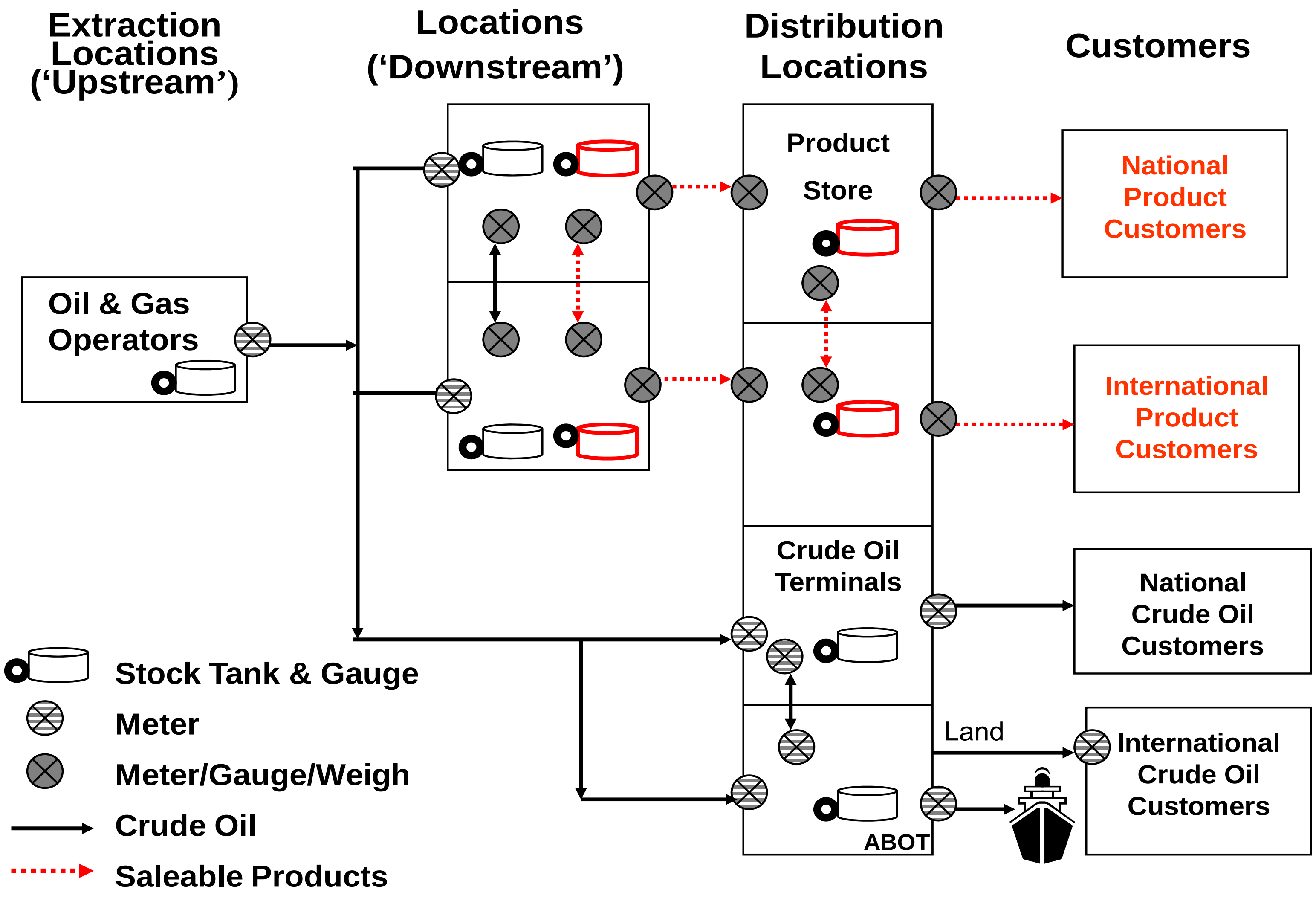
9.6 Natural Gas - Allocation Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Sharing pipelines or facilities between different companies.	Turbine, Coriolis, Ultra-Sonic, Orifice	± 2.00 - 5.00%	Gas - Chromatograph Relative Density Hydrocarbon dew-point	Meter – Quarterly DP, Press & temp. transmitters - monthly

9.7 Hydrocarbon Products - Fiscal Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Measurement with tax/royalty impact.	Turbine, Coriolis, Ultra-Sonic, PD- meter,	± 0.25%	Per contract / specification	Meter Prover - Each loading (tanks) or weekly (pipeline) Density - Quarterly Flow Proportional Sampling - Annually Laboratory Equipment - Annually Pressure/Temperature equipment - Quarterly

9.8 Hydrocarbon Products - Custody Transfer Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Product transfer between different companies, e.g. from refinery to pipeline company	Turbine, Coriolis, PD-meter Ultra-Sonic,	±0.25%	Per contract / specification	Meter Prover - Each loading (tanks) or weekly (pipeline) Density - Quarterly Flow Proportional Sampling - Annually Laboratory Equipment - Annually Pressure/Temperature equipment - Quarterly

9.9 Hydrocarbon Products - Allocation Measurement				
Typical Applications	**Meter Type**	**Uncertainty**	**Quality**	**Checking / Validation**
Sharing pipelines or facilities between different companies.	Turbine, Coriolis, PD-meter Ultra-Sonic, Orifice	±2.00 - 5.00%	Per contract / specification	Meter Prover - Each loading (tanks) or weekly (pipeline) Density - Quarterly Flow Proportional Sampling - Annually Laboratory Equipment - Annually Pressure/Temperature equipment - Quarterly

Crude Oil & Saleable Products



Natural Gas & Saleable Products