

Use of Subsea Wet-gas Flowmeters in Allocation Measurement Systems

API RECOMMENDED PRACTICE 85
FIRST EDITION, AUGUST 2003

REAFFIRMED, OCTOBER 2013



AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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FOREWORD

This Recommended Practice is under the jurisdiction of the API Executive Committee on Drilling and Production Operations. It is intended to advise the user on various aspects of the use of subsea wet-gas flowmeters in allocation measurement systems. Marinization, operation, abnormal operation, and meter testing are important topics included here, but, foremost, this document proposes novel techniques to be used in the allocation of total production to individual contributing streams.

Deepwater oil and gas prospects often employ a form of development known as a subsea tie-back. In these applications, wells are completed subsea, and production flows to host facilities for processing, generally in shallower waters, and then on to export markets. In many cases, the host infrastructure already exists, although facilities modifications may be required. Certain of these developments require commingling flow from multiple wells, possibly from multiple fields and an assortment of owners. In order to allocate production in these cases, measurement of the full wellstream fluids may be required.

Add to this the greater uncertainty of, and lack of recognized standards for, multi-phase measurement, then place the meters subsea in deep water, and one quickly enters uncharted waters.

Key to the use of multi-phase and wet-gas meters (subsea or topside) is the ability of an allocation system to account for the differential uncertainty of all the metering devices in the system. Even with established standards and practices, the process of reaching agreement on single-phase measurement allocation methodology involving multiple leases and owners is difficult. It is important to understand that subsea wet-gas meters, or any metering system in such a remote and isolated environment, are very likely to experience a higher level of uncertainty, and will probably be exposed to longer periods of undetected, uncorrected bias errors than conventional topside metering systems. When these systems are placed in a commingled operation where they provide input for an allocation of production, the financial risk to the parties involved will be greater than is normally experienced with single-phase, accessible measurement systems. This RP presupposes that these risks are recognized, and that they have been accepted by the affected parties.

This RP presents a recommended allocation methodology that is technically defensible and mathematically optimized to best fit the application, and that equitably accommodates variances in the uncertainty level between meters in the system.

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Suggested revisions are invited and should be submitted to the standardization manager, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. As it is intended for this RP to be updated within approximately one year, comments on this edition will be very much welcomed.

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Use of Subsea Wet-gas Flowmeters in Allocation Measurement Systems

1 Scope

1.1 WET GAS DEFINITION AND CLASSIFICATIONS

Defining *wet gas* is not an easy task. Historically multiphase flow where gas volume fractions (GVF) have exceeded 90% or 95% has been called wet gas. However, GVF is based on volumetric flow rates at actual conditions in the pipe, and doesn't account for relative differences in the gas and liquid densities. Since many successful devices used for wet gas measurement employ differential methods that are strongly affected by the densities of the gas and liquid relative to one another, the Lockhart-Martinelli parameter is often utilized in defining the boundary between wet gas and other multiphase flow. The Lockhart-Martinelli parameter is defined as

$$X = \frac{Q_l}{Q_g} \sqrt{\frac{\rho_g}{\rho_l}}$$

where Q_l and Q_g are the liquid and gas mass flow rates, and are the densities of liquid and gas at meter conditions. Since mass flow is volumetric flow multiplied by density, we can also define the Lockhart-Martinelli parameter of the wet gas flow in terms of actual volumetric flow rates Q_l^v and Q_g^v .

$$X = \frac{Q_l^v}{Q_g^v} \sqrt{\frac{\rho_l}{\rho_g}}$$

Based on experience gained in flow loop tests, it has been suggested that when the Lockhart-Martinelli parameter for a fluid remains below about 0.35, its behavior is such that many common methods employed for wet gas flow measurement work as they have been designed. Above this boundary these methods may begin to break down and cannot be counted on to yield reliable answers.

The magnitude of the effort that a producer should expend to estimate liquid hydrocarbon production should reflect its importance relative to the produced gas based on its mass flow rate. There will be a class of wet gas where the mass flow of liquid hydrocarbons is insignificant relative to that of the hydrocarbon gas. This shall be called Category 1 wet gas. There will also be a class of wet gas in which the liquid hydrocarbon mass flow is of sufficient magnitude to warrant its careful measurement and recovery. This shall be called Category 2 wet gas. The boundary between the two will normally be at a point where the mass flow rate of the hydrocarbon liquid is 5% of that of the gas.

1.2 LIQUID HYDROCARBON MEASUREMENT

A central problem that must be addressed for those using wet gas meters is the determination of the *liquid hydrocarbon* flow rates of a well stream. A key issue is that water and hydrocarbon liquids co-exist in the liquid phase of the stream. Furthermore, the liquid measured by the wet gas meter may contain injected chemicals (hydrate inhibitor, corrosion inhibitor, etc.), in addition to the condensate, oil, and/or water. In either case discussed below, the volume of injected chemicals flowing through the wet gas meter must be known and input to the computations.

Dependent on whether the wet gas that a particular well is expected to produce is Category 1 or Category 2, the effort to estimate liquid hydrocarbon flow rates will range from very little to very much. The general procedure will be as follows:

1. Determine if there is an online method of measuring water volume fraction available that can be used in the application.
2. Obtain and analyze a sample of the reservoir fluids for each well prior to the onset of normal production. Determine the gas-oil ratio (GOR) of each.
3. For Category 1 Wet Gas, an average GOR may be utilized across all producing wells in the system.
4. Using the GOR derived from these samples and adjusted to each allocation meter's conditions, apply these factors to the gas production for each well to obtain the liquid hydrocarbon production for each.
5. For Category 2 Wet Gas, if the liquid hydrocarbon imbalance grows beyond a predetermined threshold, one of two avenues must be pursued:
 - a. Actions must be taken to remedy the imbalance. This could involve acquiring a new sample from a well or all wells in the system, or re-estimating the GOR from secondary data sources. Strategies for doing this are considered in Chapter 7 on Abnormal Operations,or
 - b. A justification acceptable to all interested parties must be made to explain why choosing (a) is not appropriate.

In the general case, a project will consist of a combination of Category 1 and Category 2 wells, therefore the plans for production must account for this.

1.3 SCOPE SUMMARY

Until a better alternative is found, liquid hydrocarbon measurement will be accomplished by utilizing whatever sampling information is available to determine the well's water volume fraction and GOR. Dependent on the degree of difficulty in obtaining the sample and on the importance of the liquid hydrocarbon production, repeating this activity to

obtain new information on the fluid properties may be done infrequently. Although an operator will certainly have a production sample acquired from each well at its startup (i.e., from a wireline sample-taking tool, or from the flow back to the completion rig) unless the system falls out of balance, there is no requirement to take further samples.

Another problem that must be addressed is the fact that the conditions at the subsea meter will be quite different from those at the reference measurement point at the host processing facility. PVT analyses must be applied to account for phase changes incurred due to the tieback flowline length and differential water depth, as well as any other changes in pressure and temperature that might alter the phase state of the fluid. This will affect both the liquid and gas measurements, and will increase the difficulty of the task. This whole subject of mass transfer between phases and its effect on measurement uncertainty is addressed in Appendix A.

2 Referenced Publications

API

RP 17A *Design and Operation of Subsea Production Systems*
Manual of Petroleum Measurement Standards (MPMS),
 Chapter 20 "Allocation Measurement"

ISO¹

Guide to the Expression of Uncertainty in Measurement

Basil, M. and A.W. Jamieson, Uncertainty of Complex Systems Using the Monte Carlo Techniques, North Sea Flow Measurement Workshop, Gleneagles, Scotland, October 1998.

3 Definitions and Nomenclature

3.1 DEFINITIONS

3.1.1 allocation: The (mathematical) process of assigning portions of a commingled production stream to the sources, typically wells, which contributed to the total flow.

3.1.2 allocation meter: A flow measurement device used for the specific purpose of measuring the flow rates from a single well or input flowline; not to be confused with the reference meter.

3.1.3 commingle: To combine the hydrocarbon streams from two or more wells or production facilities into common tanks or pipelines.

3.1.4 Equations of State (EOS): Equations which relate the compositions, pressures, temperatures, and various other physical properties of gases and liquids to one another, and are used to predict the transformation of physical state when conditions change (see PVT Analysis).

3.1.5 error: The difference between the result of a measurement and the true value of the measurand.

3.1.6 estimate: A measurement which has been corrected to remove the effects of influence factors.

3.1.7 gas-oil ratio (GOR): The ratio of produced gas flow rate to the liquid hydrocarbon flow rate at any point, measured in standard cubic feet per barrel (SCF/BBL) or standard cubic meters of gas per cubic meter of liquid hydrocarbon (m³/m³).

3.1.8 gas (liquid) volume fraction, GVF (LVF): The fraction of the total volumetric flow at actual conditions in the pipe which is attributable to gas (liquid) flow.

$$GVF = Q_g^v / (Q_g^v + Q_l^v) \quad LVF = Q_l^v / (Q_l^v + Q_g^v)$$

3.1.9 imbalance upper/lower control limit: A limit on System Balance that is established for the purpose of maintaining control of the overall process.

3.1.10 individual allocated quantity (A_i): A contributing meter's share of the master quantity (Q_z) that incorporates a calculated share of the system imbalance (I), so that the sum of all the allocated quantities (ΣA_i) equals the master quantity (Q_z).

3.1.11 individual quantity (I_{Q_i}): The quantity determined by an individual contributing meter or measurement point.

3.1.12 individual theoretical quantity (Q_i): The quantity represented by an individual contributing meter or measurement point after conversion to a theoretical value by applying an Equation of State (EOS) or other correction factor, usually done in order to adjust the measured quantity for comparison at the same pressure and temperature base as the Master Quantity (Q_z).

3.1.13 influence factor: A quantity which is not the measurand, but which will affect the result of measurement.

3.1.14 Lockhart-Martinelli Parameter: A parameter (usually shown in equations as X) used to indicate the degree of "wetness" of a wet gas, defined as

$$X = \frac{Q_l}{Q_g} \cdot \sqrt{\frac{\rho_g}{\rho_l}}$$

3.1.15 master quantity (Q_z): The quantity measured by the reference meter(s) after commingling the individual streams.

Note: Ordinarily, measurements of this quantity exhibit a distinctively lower relative uncertainty than do the individual measurement points, since the master quantity measurements are made after sepa-

¹International Standards Organization, 11 West 42nd Street, New York, New York 10036, www.iso.ch.

ration processing, and under pressure and temperature conditions that ensure single-phase conditions.

3.1.16 mean value: The result one would obtain if a measurement were made an infinite number of times and the arithmetic average of the measurements were calculated; an estimate of the mean value based on averaging n samples is given by:

$$\bar{z} = \frac{1}{n} \cdot \sum_{i=1}^n z_i$$

3.1.17 measurand: The particular quantity subject to measurement.

3.1.18 multiphase flow: Flow of a composite fluid which includes natural gas, hydrocarbon liquids, water, and injected fluids, or any combination of these.

3.1.19 pressure-volume-temperature (PVT) relationship: Application of Equations of State (EOS) to a composite fluid to calculate the change in properties in going from one set of conditions (P and T) to another.

3.1.20 random error: The error which deviates about the mean value of the measurement in an unpredictable, bipolar fashion.

3.1.21 reference meter: A flow meter used for the specific purpose of measuring the flow rates of one phase of the commingled stream, (e.g., the liquid hydrocarbon flow rate).

3.1.22 repeatability: The closeness of the agreement between results of successive measurements of the same measurand carried out under the same conditions of measurement.

3.1.23 reproducibility: The closeness of agreement of measurement results of the same measurand carried out under changed conditions of measurement, such as different location, time, reference standard, etc.

3.1.24 sample (experimental) standard deviation: An estimate of the standard deviation based on n samples of the random variable; the square root of the sample variance.

$$\sigma_z = \sqrt{\frac{1}{n-1} \cdot \sum_{i=1}^n (z_i - \bar{z})^2}$$

3.1.25 sample (experimental) variance: An estimate of the variance based on n samples of the random variable,

$$\sigma_z^2 = \frac{1}{n-1} \cdot \sum_{i=1}^n (z_i - \bar{z})^2$$

3.1.26 specified imbalance limit: A limit on System Balance which is established for the purpose of satisfying contractual obligations and/or regulatory requirements.

3.1.27 standard deviation: The square root of the variance of a random variable.

3.1.28 system imbalance (I): The difference between the measured Master Quantity (Q_z) and the sum of the Individual Theoretical Quantities ($\sum Q_i$), sometimes referred to as the System Balance.

3.1.29 systematic error: The difference between the mean value of a measurement and its true value, generally a constant or near-constant value.

3.1.30 true value: The underlying characteristic of the measurand which would be recorded if the measurement were perfect, (i.e., there were no random or systematic measurement errors).

3.1.31 uncertainty (of measurement): A parameter associated with the result of a measurement that characterizes the dispersion of the values that could be reasonably be attributed to the measurand, often expressed in terms of its variance or standard deviation.

3.1.32 uncertainty-based allocation: A method of hydrocarbon allocation in which the relative uncertainties of the measurements are taken into consideration, including measurements made by each of the allocation meters, by the reference meters, and by any other instrumentation, the readings from which affect hydrocarbon flow measurement.

3.1.33 uncertainty of allocation meter: The uncertainty of an Individual Theoretical Quantity relative to the flowing conditions experienced by the meter, which includes the uncertainty of the meter, any uncertainty in EOS application, and the uncertainties due to errors of ancillary devices such as pressure and temperature.

3.1.34 uncertainty of reference meter: The uncertainty of the Master Quantity relative to the flowing conditions experienced by the meter.

3.1.35 variance: The expected value of the square of the difference between the measurement and its mean value.

3.1.36 watercut (water-liquid ratio): The volumetric fraction of water in a liquid stream composed of water, liquid hydrocarbons, and perhaps other liquids.

3.1.37 water volume fraction: The volumetric percentage of water in a total fluid stream composed of water, liquid hydrocarbons, other liquids, and gas.

3.1.38 wet gas: A particular form of multiphase flow in which the dominant fluid is gas and in which there is a presence of free-flowing liquid.

Note: There are several ways of more precisely defining wet gas, as discussed in 1.1.

3.2 NOMENCLATURE AND SYMBOLS

Symbol	Meaning
α_i	Allocation Factor used for Assigning Imbalance to the i^{th} Meter
α_i	Fraction of Liquid Converted to Gas in Transport from Subsea to Platform
A_i	Individual Allocated Quantity
β_i	Fraction of Gas Converted to Liquid in Transport from Subsea to Platform
EOS	Equation(s) of State
GOR	Gas-Oil Ratio
GVF	Gas Volume Fraction
I	System Imbalance
IQ_i	Individual Quantity
LVF	Liquid Volume Fraction
M	Murdock Coefficient
m_g	Gas Mass
m_l	Liquid Mass
MW_g	Average Molecular Weight of a Gas Mixture
MW_l	Average Molecular Weight of a Liquid Mixture
MW_i	Molecular Weight of the i^{th} Component of a Mixture
n_g	Number of Moles in a Gas Mixture
n_l	Number of Moles in a Liquid Mixture
n_g^i	Number of Moles of the i^{th} Component of a Gas Mixture
\dot{n}	Total Molar Flow Rate (Gas Plus Liquid)
\dot{n}_g	Gas Molar Flow Rate
\dot{n}_l	Liquid Molar Flow Rate
P_p, T_p	(Platform) Pressure and Temperature
P_s, T_s	(Subsea) Pressure and Temperature
PVT	Pressure-Volume-Temperature
Q_i	Individual Theoretical Quantity
Q_g	Gas Mass Flow Rate
Q_{gi}	Indicated Gas Mass Flow Rate
Q_g^v	Gas Volume Flow Rate
Q_{gs}	(Subsea) Gas Mass Flow Rate
Q_{gp}	(Platform) Gas Mass Flow Rate
Q_l	Liquid Mass Flow Rate
Q_l^v	Liquid Volume Flow Rate
Q_{ls}	(Subsea) Liquid Mass Flow Rate
Q_{lp}	(Platform) Liquid Mass Flow Rate
Q_z	Master Quantity
ρ_g	Gas Density
ρ_l	Liquid Density
σ	Standard Deviation of a Random Variable
σ^2	Variance of a Random Variable
T_l	Imbalance Limit
X	Lockhart-Martinelli parameter

x	Gas Mass Fraction
x_g^i	Mole Fraction of the i^{th} Component of a Gas Mixture
x_l^i	Mole Fraction of the i^{th} Component of a Liquid Mixture

4 Subsea Meter Calibration and Testing

4.1 GENERAL

This section addresses testing and calibration of meters that is performed for the purpose of qualification, prior to installation for actual field operation.

The status of multiphase measurement for wet gas service is immature. Accepted calibration practice uses test and production separation techniques, which rely on separation and metering of each individual phase to known standards by traditional methods and metering equipment.

Further complicating the situation is the subsea location of these meters when in service. This means that not only are they unavailable for removal and verification of their performance, but that even routine test and inspection of sensors and other components is extremely difficult.

The following describes what reference loop testing is required prior to a meter's being declared qualified for subsea wet-gas service, what these reference facilities must possess in order to be certified as fit for the task, and what a successful calibration test should entail.

4.2 TESTING REQUIREMENTS

The nature of multiphase flows is complex. It is much more difficult to assure the reproducibility of fluid flow behavior at flow measurement sections—at different installation locations and through service life—than is the case for single phase flow. This results in a significantly higher degree of uncertainty in meter calibration for multiphase applications.

4.2.1 Meter Calibration Testing

Each flow meter design used for a specific wet gas application shall be qualified prior to use. A meter in an application may be exempted if it has already been qualified for the same application. Qualification testing should subject the actual meter design to the full range of conditions expected. This includes phase flow rates, pressures, temperatures, and fluid properties, using test fluids exhibiting similar properties and phase mass transfer behavior to the in-situ application process fluids. The meter under test shall be installed in a piping configuration similar to that of the intended service installation configuration, to demonstrate that it meets the uncertainty requirements over the range of flow conditions specified for the application. Reference meters used in this testing should meet the requirements of 4.3.1.

Some of the parameters which should be considered are the following.

4.2.1.1 Installation Pipework. Depending on the technique of multiphase flow measurement and the type of sensor technology used, the meter's response may be influenced by geometrical details of the surrounding pipework. To the maximum degree possible, the meter installation at the flow facility should be made to mimic that which will be implemented in the application.

4.2.1.2 Meter Size. Bulk flow rates requiring a previously unqualified meter size (both nominal diameter and meter opening) may necessitate testing of the specific proposed meter type of that size. Depending on the technique of multiphase flow measurement and the type of sensor technology used, meter response may be influenced by geometrical, dimensional and material specifications. The extent of the testing will be dependent on the meter's performance during testing as compared with previously qualified similar meters of a different size.

4.2.1.3 Fluid Properties. Meter response also depends on how sensors respond to changes in fluid properties such as salinity (conductivity), viscosity, density, etc. Consideration must be given to how closely the test facility can replicate the fluid properties expected. Furthermore, this and the pipework discussed above are the determining factors of flow regime. It must be demonstrated that the flow regimes tested are representative of those which are expected to be encountered in practice.

4.2.1.4 Operating Range. The proposed test facility should, to the maximum extent possible, operate over a similar range of phase flow rates, pressures, and temperatures to that expected in the application. It is recommended that testing be performed extending the operating range into anticipated transient start-up temperatures and pressures.

4.2.2 Meter Component Calibration Testing

Although the focus of this discussion has been the flow calibration testing of the wet gas meters themselves, it is of great importance to test individual components as well. Some of these tests are discussed below.

4.2.2.1 Sensor Testing. All sensors which are to be used in the meter shall be tested and calibrated under conditions which replicate the application environment as closely as possible. To the maximum extent possible, tests should replicate the anticipated production flow meter design for sensors and sense tubes, so as to increase the likelihood of identifying any unexpected or unintended affects.

4.2.2.2 Electronics Testing. Even though it is unlikely that electronics will be directly exposed to either subsea or well fluids, it is likely to experience thermal and possibly pressure stresses, therefore a test program to demonstrate its survival in the conditions of the application is mandatory.

4.2.2.3 Pressure Testing. All meter parts which are subject to either internal or external pressures, or both, as well as the complete meter itself, must be tested in as realistic a manner as is possible.

4.2.3 Factory Acceptance Testing (FAT)

It is recommended that at the factory of the supplier, or at another location agreed to by the parties, each meter, meter component, and the complete meter system be operationally tested.

Testing of individual meters or components should be conducted under as realistic conditions as possible over a reasonable range of input conditions, noting any deviations from specification.

In testing the complete metering system, it should be connected as it will be when installed subsea. This may or may not require an actual flow test, but should demonstrate the complete suite of functionality which will be employed when the metering system is in actual operation.

In this activity all aspects of the meters, meter components, and metering system operation should be simulated, and the response of the system observed. Any errors or anomalies should be noted, and either corrected or explained prior to the system's deployment.

4.3 FLOW TEST FACILITIES

Flow testing shall be carried out at a flow laboratory which is capable of matching the requirements of the application as detailed in 4.2.1. These flow test facilities may be specially built reference facilities, or may be part of a hydrocarbon production or transportation facility. The flow test facilities shall provide for witness testing, for traceability and calibration documentation, and for all pertinent facility and test data records. Test program management protocols shall assure the interests of all investing parties, and shall impose and enforce an agreed demarcation on what test data constitute calibration, validation and repeat test points respectively.

4.3.1 Reference Measurement

The quantities of each individual phase of the multiphase fluid to be tested shall be measured in a separated state on the test facility. Either closed-loop (circulating) or open-loop (pass-through) flow facilities may be used. Each single phase shall be measured as follows for use as the reference measurement in the meter calibration calculations.

4.3.1.1 Traceability. Flow test facilities shall employ reference measurement systems which have been calibrated against recognized traceable national standards. Where the practicalities of a particular test facility do not allow full traceability (e.g., producing oil or gas field), the reference measurements may be used where it can be demonstrated that

good flow process design and measurement practice have been applied.

4.3.1.2 Instrumentation. Reference measurement instruments shall be of a suitable type as used to determine the flow rate and quality of flow streams to high accuracy. The reference measurement uncertainty requirement shall be based on the uncertainty specification of the specific wet-gas meter under test. The reference measurement uncertainty shall be no more than 10% of the uncertainty specified for the meter under test, for each phase at application pressure and temperature.

4.3.1.3 Measurement Correction. The reference phase flow rate measurements shall be corrected to values corresponding to the process pressure and temperature at the meter under test for each test point condition. Industry-accepted EOS algorithms shall be applied using pressure and temperature measurements at the reference meter tubes and at the meter under test. An estimate of the uncertainties introduced by this conversion process shall be incorporated into the overall uncertainty analysis.

4.3.2 Test Facilities

The operation of the qualification test facility shall incorporate process efficiency monitoring measures and reporting. This shall identify and include all necessary instrumentation to assure flow process efficiency. Measures shall be taken to assure a minimum level of un-measured phase cross-contamination through the reference measurement systems. Typical examples of phase cross-contamination in reference measurement systems are the carry-over of liquid into the gas off-take, gas carry-under into the liquid leg, or water carry-over into the oil leg of phase separation measurement systems.

4.3.3 Test Period

Test period selection shall insure that the test data flow readings and computations are recorded only when the flow conditions—phase flow rates, pressures and temperatures—are stable (i.e., all transducer signals are statistically stationary). Computation of average flow quantities shall extend over time periods sufficient to render negligible any statistical uncertainty due to flow and signal fluctuations.

4.3.4 Test Fluids

The qualification test fluids shall exhibit properties, such as density, viscosity, surface and interfacial tension, conductivity, and dielectric constant, representative of the in-situ process fluids at the metering station during its service life. This shall account for the influence of injection chemicals to be used upstream of the measurement station during operations. The test fluids shall exhibit phase change mass transfer characteristics similar to the application fluid system, unless there is strong evidence from previous test and operation to show

that phase change through the multiphase meter measurement section has a negligible influence

4.4 CALIBRATION TEST PROGRAM

4.4.1 Test Matrix

The test matrix shall cover a range of the phase flow rates, pressures, temperatures, and fluid property conditions, which adequately represent the operating envelopes of the duty meter through its service life. In most cases, it is recommended to test beyond the operating range specified in the application, especially with respect to anticipated start-up conditions. It is recommended that the test envelope shall extend beyond this range to the extent necessary to permit the fitting of calibration algorithms. Extension of the test envelope, where possible, should insure that the calibration algorithm also covers operating conditions just outside the predicted range.

4.4.2 Extrapolation of Test Points

Where the practical limits of the fluid flow operating envelope of the qualification test facility cannot fully cover the fluid flow envelope of the application, calibration and performance validation may be determined by extrapolation. Any such extrapolation shall be supported by analysis of the fluid flow conditions and the impact of these on the calibration uncertainty for the meter under test within the extrapolation zone. This analysis shall account for the influence of fluid dynamic behavior and instrument response within the zone of extrapolation. It must be supported by other substantive recognized test and analytical or theoretical evidence.

4.4.3 Determination of Test Point Conditions

An analysis shall be made of the predominant influence factors of the meter under test to determine the major and minor variables influencing meter response, as well as the respective resolution and number of test points required for each variable. The selection of test point conditions shall also account for the relative operational impact of measurement uncertainty within the duty envelope and populate matrix data accordingly. This shall include as a minimum variation in pressure, gas flow rates, and liquid flow rates.

4.4.4 Test Execution

A description of the planned test with respect to parameters such as fluids to be used, pressure, temperature, etc. shall be prepared prior to the onset of testing. During the execution of the test all sensed parameters shall be acquired and recorded. Acquisition of data points should occur only after complete stabilization of all parameters.

The following types of test points shall be used throughout the test matrix. All are required for determining the calibra-

tion parameters and evaluating the performance of the test meter and test facility.

4.4.4.1 Calibration. Test points where the reference phase measurements are used specifically to determine the calibration curve.

4.4.4.2 Validation. Test points where the output from the test meter is used (via the calibration curve) to predict the gas and liquid flows. These values are then compared to the reference phase measurements to determine test meter performance.

4.4.4.3 Repeat. Selected points covering the flow operating envelope should be subject to repeat testing. It is recommended that 20% – 40% of the test points in the calibration and validation matrix be repeated.

Distribution of calibration and validation points should be approximately 50:50. Outliers must be reported. A reasonable attempt to investigate and explain outlying measurements must be made.

4.4.5 Allowance for Spare Test Time

The test program should include spare capacity within the schedule to allow for unforeseen system faults such as:

- a. changes or additions to the number of test point conditions in order to adequately examine unforeseen phenomena or previously unidentified meter characteristics,
- b. troubleshooting of test facility or meter performance, or
- c. investigation of outliers, including repeat runs of these test points as necessary.

Test loop and test meter performance should be continuously evaluated during the test program to assure optimum operation and allow for matrix modifications if needed to improve the meter calibration.

4.4.6 Other Evidence

Published data and analyses concerning wet gas multiphase metering may be used to help determine the needs, scope and detail of the qualification test program. Such references may further be consulted during and after the completion of the test program to support analysis, results, conclusions and statements.

4.5 CALIBRATION DELIVERABLES

4.5.1 Meter Calibration

The qualification test and analysis program shall produce the calibration results of the meter under test, applicable to the range of fluid flow start-up and operating conditions, and the corresponding statement of uncertainty.

4.5.2 Uncertainty Analysis

The uncertainty analysis shall account for uncertainties added by changes made in hardware and software between the qualification test system and the installed application measurement and production reporting system. (This shall include but not be limited to, differences with respect to signal transmission fidelity, resolution, accuracy, repeatability and timing, data storage and flow rate computation and reporting accuracy and format).

For fiscal allocation, the full uncertainty chain, from national or international reference standards through field-installed calibrated measurement system to production reporting, shall be analyzed, by recognized metrological means of analysis, to estimate the overall measurement uncertainty.

5 Allocation Methodology

5.1 INTRODUCTION

Allocation methods involve the distribution of revenue. Central to the use of wet gas meters in the subsea environment is the allocation philosophy and methodology that accounts for differences in the relative measurement uncertainty of various meters within a given allocation system.

Allocation of the so-called *imbalance* between one set of high-accuracy meters and a set of lower-accuracy meters, the flows from which are commingled, is normally done in a pro-rata method using relative throughput as a basis. This is the method dictated in the API Standard for conventional allocation, API *MPMS*, Chapter 20, Section 1. An example of its use might be allocation of the readings of a sales gas meter back to meters located downstream of the separator vessels. While this is very effective for many measurement systems, it assumes equal uncertainty among all the lower-accuracy meters. This straightforward approach must be modified to accommodate systems where there may be wide variation in the accuracy of individual allocation meters, which is often the case with subsea measurement, or instances where the production through subsea meters is commingled with that flowing through topside meters. If no accommodation is made for this discrepancy, the allocation among producers is almost guaranteed to be unfair. The methodology which has been developed to address the equitable distribution of the system imbalance is called *Uncertainty-based Allocation*, and will be described in the paragraphs which follow.

5.2 PRINCIPLE

An allocation methodology must be used which incorporates the random uncertainty of each meter within the set of meters, relative to the uncertainty of the whole set. This will thereby effectively and fairly assign the system imbalance to those meters or processes most likely to have caused the difference.

The resulting imbalance between the contributing meter quantities and the master quantity can then be assigned to each individual meter on a basis of the throughput and the meter's uncertainty relative to the uncertainty of other meters in the set. By applying this method only to the portion of the system imbalance created by the random uncertainty, the resulting imbalance can be equitably assigned to each contributing meter. Therefore, it is reasoned that a meter with a large throughput ratio and an uncertainty level well above the average will likely be assigned the largest portion of the imbalance.

It should be noted that the techniques described here are applicable not just at the beginning of a project, or with existing measurement systems, but are particularly useful when one or more meters are being added to a system already in place, as in the case of tie-backs. In these cases a new set of calculations like those shown below will need to be made.

Subsea flowmeters will normally be installed for an indefinite (often long) period of time. Within a set of meters of a common design changes to meter accuracy (creep) due to erosion or other reasons over time will be assumed to be the same for all meters within this meter set unless specific information to the contrary becomes available.

5.3 VALIDATION OF PERFORMANCE AND APPLICABILITY

While the allocated quantities may be calculated per the algorithms listed herein, one must realize that the process is dependent upon the principle that the entire system imbalance is created in a random fashion, and thus directly related to the uncertainty of the individual contributing meters. Other measurement errors (i.e., non-random, or systematic) need to be eliminated before performing the uncertainty-based allocation. Thus, a process of validating the system performance needs to accompany the uncertainty-based allocation in order to ensure that the allocation is equitable within an acceptable level.

Systematic measurement errors, which affect the contributing meters in a like manner, create an on-going, repeatable imbalance. Since the magnitude of these errors for a given meter is constant on a relative percentage basis, their effect should be corrected on a purely pro rata throughput basis, without consideration for random uncertainty. Normally, pre-deployment flow tests are conducted on the metering systems in order to calibrate the meters and thus eliminate the majority of the systematic errors. However, systematic errors determined after deployment through analyzing and trending the system balance performance, should also be quantified and rectified through use of generalized meter factors. Further, any measurement errors determined after the fact within the Master Quantity determination should be assigned under a purely throughput pro rata basis given that the effect would not be related to the relative uncertainty of the individual contributing meters.

Another consideration which must be made when applying these methods is that readings from all flow meters must be brought to a common set of conditions. Methods for doing this are referred to as *PVT Analysis*, or the application of *Equations of State*. Appendix A explains how these kinds of methods should be applied when using this Uncertainty-based Allocation Methodology.

5.4 DERIVATION OF ALLOCATION FACTORS AND ALLOCATED QUANTITIES

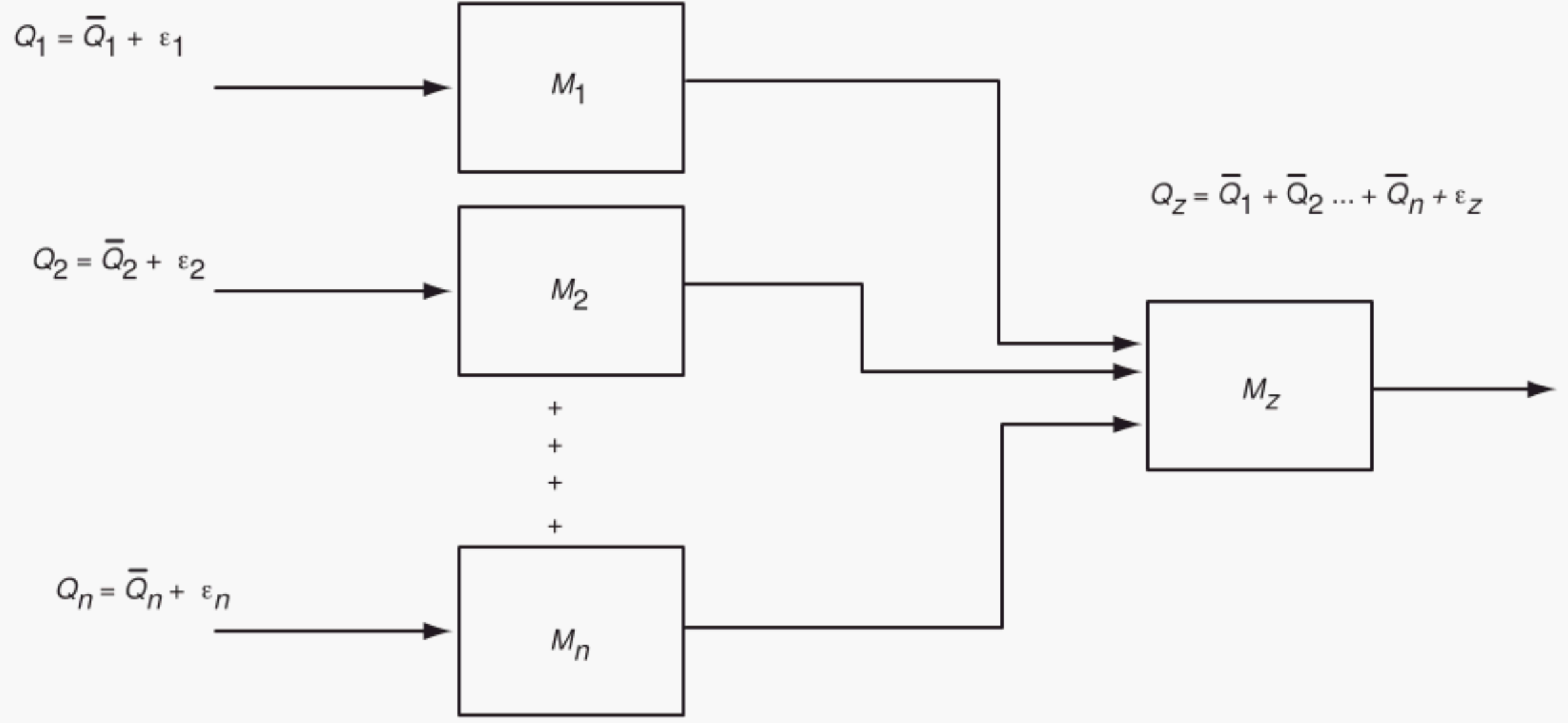
The principle of uncertainty-based allocation is illustrated by the accompanying Figure 1. The reading of the high-accuracy meter M_z which measures the commingled streams is the Master Quantity Q_z , while the readings from the lower-accuracy meters of individual streams through the meters M_i , transformed to the phase conditions of M_z , are the Individual Theoretical Quantities Q_i also known as each meter's throughput. Though the meter M_z is generally of high accuracy and the meters M_i of lower accuracy, the methods developed here do not depend on this condition, and can be applied in cases where these conditions are not met.

The difference between the master quantity and the sum of the of the individual theoretical quantities is defined as the System Imbalance I , where

$$I = Q_z - \sum_1^n Q_i$$

In pursuit of an equitable means of allocating the system imbalance, it is argued that this difference should be allocated to the individual contributing wells based in some way on the relative magnitudes of their throughput Q_i and their measurement uncertainties. Each stream would be assigned an *allocation factor* α_i which would identify the fraction of the imbalance which it would be required to accept. Since all the imbalance must be assigned to the contributing meters, the sum of the allocation factors must be unity. The goal then is to choose the allocation factors α_i so that in a *stochastic* sense the error made is minimized.

Implicit in this discussion is that the uncertainty of each meter's readings can be characterized in a quantitative fashion. While this might be a straightforward task for single-phase meters, clearly it is a nontrivial exercise for users of wet gas meters. Essentially the meters must be tested in a calibration facility capable of replicating the conditions which will be encountered in normal operation, and the uncertainty must be measured at each of these conditions. From these data an uncertainty model must be constructed over the entire operational range. More information on uncertainty can be found in the ISO publication on the subject, *Guide to the Expression of Uncertainty in Measurement*.

Figure 1—Commingling n Production Streams Q_i to Form Stream Q_z

Returning to the allocation example shown in Figure 1, consider the case where n streams are commingled. The streams through the meters $M_1, M_2 \dots M_n$ are commingled and subsequently measured by a high-accuracy meter M_z . We can write each of the measurements as the sum of a true value (denoted by an over-bar) and an error term,

$$Q_1 = \bar{Q}_1 + \varepsilon_1$$

$$Q_2 = \bar{Q}_2 + \varepsilon_2$$

⋮

$$Q_n = \bar{Q}_n + \varepsilon_n$$

$$Q_z = \bar{Q}_z + \varepsilon_z = \bar{Q}_1 + \bar{Q}_2 + \dots + \bar{Q}_n + \varepsilon_z$$

$$I = Q_z - \sum_{i=1}^n Q_i$$

Here we make the assumption that any systematic errors have been eliminated during the calibration of the meters, so that the *errors* in Q_1, Q_2, \dots, Q_n and Q_z are *zero-mean* random variables with (measured) characteristic variance $\sigma_1^2, \sigma_2^2, \dots, \sigma_n^2$ and σ_z^2 . Furthermore, we assume that the error in measurement of each of the streams is stochastically independent from that in any other stream, (i.e., a measurement error in M_1 is unrelated to a measurement error in M_2, \dots, M_n), and none is related to a measurement error in meter M_z .

We propose the following allocation factor be used to distribute the imbalance between the streams:

$$\alpha_i = \frac{\sigma_i^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} + \frac{Q_i}{\sum_{j=1}^n Q_j} \cdot \frac{\sigma_z^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} \quad (1)$$

The factor shown can be interpreted as allocating the imbalance based on the relative uncertainties of the individual meters and that of the reference meter. In the first term it can be seen that the factor is the ratio of the uncertainty of the i^{th} allocation meter, expressed as its variance σ_i^2 , to the sum of the uncertainties of all the meters in the system. The second term in the factor distributes a portion of the imbalance over all the streams based on the reference meter uncertainty, σ_z^2 . This distribution is based on the throughput of each stream relative to that of the others. Note that the sum of the factors is unity, as it should be.

In Appendix E it is shown that the assignment of allocation factors shown above is very nearly optimal in the sense that it minimizes the expected value of the allocation error.

One last issue to be addressed is the way in which uncertainties are accounted for in the measurement of gas diverted for other purposes, such as flare or fuel. Since the measured gas output on the platform is the sum of the measurements or estimates of gas flowing through the sales meter plus any other lines, we can write an equation for the output sum Q_z as

$$Q_z = Q_{\text{sales}} + Q_{\text{fuel}} + Q_{\text{flare}} + \dots \quad (2)$$

Incorporating the true values of sales, fuel, flare, and any other flow rates, and then recognizing the stochastic independence of the individual measurement errors on these quantities, the variance of the error in measuring Q_z can be written as

$$E\{(Q_z - \bar{Q}_z)^2\} = E\{(Q_{\text{sales}} - \bar{Q}_{\text{sales}})^2 + (Q_{\text{fuel}} - \bar{Q}_{\text{fuel}})^2 + (Q_{\text{flare}} - \bar{Q}_{\text{flare}})^2 + \dots\} \quad (3)$$

$$\sigma_z^2 = \sigma_{\text{sales}}^2 + \sigma_{\text{fuel}}^2 + \sigma_{\text{flare}}^2 + \dots \quad (4)$$

Simply substituting the values for the variances on the sales gas measurement and those of the flare and fuel measurements (or estimates) into the appropriate places in Equation (1) yields the correct allocation factors for the gas part of the system which incorporate the effects of all these uncertainties. There may be other specific instances like these where a portion of the collected hydrocarbons are directed elsewhere, such as gas lift, circulation of pigs, etc. For these cases, the user should develop a simple extension to the techniques shown here.

5.5 APPLICATION OF THE ALLOCATION EQUATIONS

In order to apply the equations developed here to allocate the System Imbalance back to the individual production streams, the uncertainties in gas and liquid flow should be known at reference meter conditions. Appendix A discusses how this can be done.

It should be noted that with knowledge of composition at both the allocation and reference meters, measurements of gas and liquid mass flow rates and uncertainties can be converted to component flow rates and uncertainties. These can then be used to allocate the constituent totals back to the individual streams in the general case where the stream compositions differ.

It is anticipated that normally the computation of System Imbalance for both gas and liquid flows will be in units of mass. This is not absolutely essential, however, as the calculations can be made on a volumetric basis as long as it can be shown that this is being done properly. However, the System Imbalance is most easily distributed back to the contributing meters on a mass basis, hence this method is strongly preferred.

5.6 PERSPECTIVE ON ALLOCATION: THE IMPACT OF SYSTEMATIC ERRORS

What has been developed here has made the assumption that measurement errors on all meters are unbiased, (i.e., there is no systematic component to deal with). The reason for this was simply that the mathematical derivations became easier, and insight could be gained by formulating equations, such as Equation (1) in 5.4, in this way. However, in the real world this assumption is rarely, if ever, completely valid. Even if the allocation and reference meters were unbiased when installed,

this condition will almost certainly change with time. Dimensions will change, sensor readings will drift or shift, assumptions concerning fluid properties will no longer hold. Subsea meters, with no in-situ proving, no regular sampling, and no ability to calibrate instrumentation, must operate where ongoing bias errors may exist undetected for long periods. While in certain cases some of these effects can be detected and accounted for, it is not uncommon for systematic errors to grow and to escape routine detection, perhaps even for the life of the device. This is especially true for subsea meters, due to their remote and generally inaccessible locations.

So it is reasonable to ask how useful is the allocation methodology developed here, and how should it be applied. The answer to the second question is that a rigorous program for sensing, correcting (where possible), and accounting for systematic errors down to the sensor level must be instituted at first calibration and continued throughout the life of the field. Only through continuing diligence will their effects be minimized.

The first question is not so easy to deal with, but can be partially answered by recognizing that any allocation scheme one can envision will be affected by the presence of undetected systematic errors. Unless the efforts at detecting bias errors yield fruit, this measurement inequity will be distributed—whether by Uncertainty-based Allocation or by any other method—to all the streams which are commingled.

Furthermore, one can argue that meters with large *random* measurement uncertainties are more likely to have large *systematic* errors than meters with smaller measurement uncertainties. If this is so, Uncertainty-based Allocation would assign the largest portion of an imbalance due to both systematic and random errors to those streams which are most deserving. Conversely, if the owner of a stream diligently maintains a low metering uncertainty, keeping control over sources of systematic errors, his reward will be that he receives little or none of the imbalance, whether from random or systematic errors. Obviously this methodology provides a strong incentive for partners to keep their meters in top working order.

In summary, it is worth noting that any form of subsea allocation brings with it risks like those described above. Users must be aware that these risks exist, and that they will probably be greater than those in well-defined, controlled, and predominately single-phase measurement systems (topsides facilities). The user must assess his willingness to accept the measurement exposure outlined here before agreeing to a commingling arrangement using subsea metering systems.

6 Installation, Operability, Physical Requirements

6.1 OVERVIEW

When installing measurement equipment on the sea floor, it is clearly of great importance that the proper installation and normal operation be well understood and documented in detail. The purpose of this section is to recommend proce-

dures for insuring that this is, in fact, both documented and achieved in practice.

6.2 NORMAL OPERATING CONDITIONS OVER FIELD LIFE

The range of conditions in which the subsea metering system is expected to operate must be defined in detail. This is true not just for the initial conditions of the environment, but for what is expected over the useful life of the field.

Some of the parameters that should be addressed in this discussion are the following.

6.2.1 Pressure. It is standard practice prior to field development to create reservoir production models showing how pressure and flow will vary and ultimately decline over the life of the field. It is a crucially important tool for determining the quality of measurement to be expected, hence accurate measurement and compensation of pressure is essential.

6.2.2 Temperature. Likewise, some of the sensors and many of the calculations which will be used in subsea measurement require a knowledge of temperature, so knowing its range and measuring it accurately is of great importance. Furthermore, most instruments have a limited thermal operating range, particularly at the high end, so the proper meter choice requires an estimate of the temperature profile expected during the field life. Conversely, initial start-up temperatures can be unexpectedly low enough to be “out-of-range” if careful consideration is not given to this aspect.

6.2.3 Flow Rates. While this is clearly something the operator has some control over, it is necessary that anticipated flow rates are specified. This demonstrates that the metering solution chosen is, in fact, capable of doing its job over the full range of flows, (i.e., the meter has sufficient *turndown* for the job). The gas and liquid flowrates over the well lifetime (the well trajectory) should be plotted together with the operating envelope of the meters in the two-phase flow diagrams.

6.2.4 Gas and Liquid Volume Fractions (GVF/LVF). Another key set of parameters that must be discussed are those associated with the relative production of gas and liquids from the field. These may be defined in various ways, some of which are gas volume, liquid volume fraction, gas-liquid ratio, and Lockhart-Martinelli parameter. It is a fact that the performance of virtually all multiphase flow meters is strongly dependent on the relative amounts of gas and liquid in the mixture being measured.

6.2.5 Water Volume Fraction, Watercut. The water in each stream, as well as the amount of water relative to the hydrocarbon liquids anticipated, are important parameters. This is important not just from the economic perspective of hydrocarbon production, but also because flow meters often respond in different ways in the presence of water variation. Expected GVF and water volume fraction over the lifetime of

each well should be plotted in the two-phase composition map, and should be compared with the known operating envelope of the meter.

6.2.6 Fluid Properties. It is important to know as much as possible about the fluid properties of both gas and liquid phases, particularly with regard to flow measurement. Parameters such as gas density, liquid density both for water and for hydrocarbons, liquid viscosity, and water salinity are examples of fluid properties that are needed for measurement design. For gas/condensate systems the molar composition is important and should be known to calculate the phase transformations between the subsea and the top site conditions.

6.3 MEASUREMENT UNCERTAINTY EXPECTED FOR NORMAL OPERATING CONDITIONS

The parameters listed above are likely to vary considerably over the life of the field. Since the accuracies of wet gas meters are strongly dependent on these parameter values, in applying for permission to use a particular measurement system it is important that the applicant show how the measurement uncertainty is likely to change with time.

For instance, in early days of production, reservoir (and hence pipeline) pressures are generally high, hydrocarbon flow rates are likewise high, and water production is low. As the field grows older, these conditions often deteriorate, with pressures and flow rates tailing off and water production increasing. If a measurement system is designed solely for the conditions of initial production without regard to measurement late in life, significant problems with flow rate accuracies may be the result.

A second issue in identifying uncertainty is how the user deals with unknown systematic measurement errors that can be inherent in a metering system. Unless systematic errors are routinely identified and eliminated in a rigorous manner, the use of uncertainty-based allocation will be difficult and some users will not receive a fair share.

6.4 DESIGN CONSIDERATIONS

Since the measurement system will normally be active for many years on the sea floor without intervention, insuring that it is properly designed for such operation is a key step in preparing the application for permit. Listed below are some of the factors which should be considered.

6.4.1 External Design Pressure. During operation, conditions of low internal pressure will exist, (e.g., installation, hydrate remediation, depressurization, etc.). The meter and its components must therefore be designed to sustain full external hydrostatic pressure. All components must be subjected to hyperbaric testing.

6.4.2 Internal Design Pressure. During hydro-testing of flowlines, the meters will experience high internal pres-

tures, and must therefore be designed to withstand the full hydrostatic test pressure. The absolute internal pressure may be experienced across piezoelectrics and transducers which contain cavities at atmospheric pressure. These components must therefore be designed to sustain the maximum *absolute* internal pressure.

6.4.3 Material Selection and Manufacture. It is well known that using certain materials in combination with one another, particularly at long-term extremes of temperature, can cause internal and/or external corrosion and possible failure. In many cases exotic materials will be used which will need careful attention, particularly with regard to welding procedures for service in seawater. The applicant must show that he has considered the question of material selection for the environmental and production conditions in place, and has taken appropriate design steps to insure that the potential problems have been addressed. This should include compatibility with cathodic protection systems.

6.4.4 Erosion and Corrosion. Because of the difficult access to the meters when installed subsea, it must be demonstrated that care has been taken by the applicant to prevent alteration of the dimensions of the measurement device by any means, but particularly by either internal corrosion or erosion. For example, orifice plates may suffer erosion over time when measuring the flow of raw well gas. The sensitive dimensions of the orifice plate gradually change, and the meter loses its accuracy, thereby requiring replacement. For Venturi meters and similar tubular meters, erosion is generally not a problem of the same magnitude as for the orifice, since its key dimensions are distributed over a larger area. A combination of special coatings and carefully chosen materials can mitigate these effects.

Another consideration is the need for external coating selection and cathodic protection systems to mitigate the affects of external corrosion. The interested reader should consult API RP 17A on cathodic protection.

6.4.5 Hydrate Susceptibly Analysis. A significant problem facing producers, especially those who put their meters in the cold subsea environment, is the possibility that any water produced from the reservoir may lead to the formation of hydrates, which may reduce and even completely choke off production, as well as debilitate individual sensors. It must be shown that the producer has considered the fluids produced under varying pressure, temperature, and flow conditions, and has designed piping and additive strategies to prevent hydrate formation. Care must be taken to ensure that all the piping, meters, sense lines, and sensors are considered as potential locations for hydrates to form, thereby preventing accurate measurement. Special consideration should be given to residual seawater, (e.g., from installation and hydro-test), exacerbating potential for hydrate formation, especially during start-up.

6.4.6 In-situ Re-calibration. Although it is unlikely that any technique for flow-calibrating a meter in place will be available in the foreseeable future, it is certainly possible to envision methods for performing limited calibrations of individual sensors. For example, for differential pressure devices any zero shift can be detected and corrected by software means during the required periodic shut-in of the wells to test the downhole and surface isolation valves. Methods such as this for checking and re-calibration are recommended. In some cases differential pressure sensors may cover different ranges. In these instances, it may be desirable to re-scale a sensor to operate in a range of differential pressures other than that for which it was originally intended. The goal should be to use any opportunity to evaluate the sensor performance, and where possible to use software methods for re-establishing the desired sensitivity and zero offset.

6.4.7 Sensor Redundancy. It is recommended that at least one level of redundancy of all sensors be provided, and that more may be necessary in many instances. It is up to the applicant to design the system of redundancy, and to describe the methods of using both primary and backup sensors to validate proper operation or to detect failure.

Also, multiple sensors may be used to provide a greater measurement range in some instances, such as differential pressure devices with enhanced turndown, where one DP sensor is used for low flow rates and another for higher rates. It is the responsibility of the applicant to describe the method of combining the outputs of both sensors for measurement of flow.

6.4.8 Leak Path Minimization. In deep water, the reliability of the equipment can govern the ability of the system to function at all. Both internal and external leakage can cause environmental or liquid ingress problems. To mitigate this potential hazard, the number of pipework connections used in the metering system should be minimized so as to reduce the likelihood of such connections becoming loose and thereby creating a leak. Where pipework or sense line connections are required, the highest attainable quality connection methods should be considered.

6.4.9 Installability/Removability from Service. It is a requirement that measurement systems be installable and retrievable remotely via Remotely Operated Vehicle (ROV), or downline assisted by ROV. Applicants must demonstrate that their pipework layouts are designed to permit straightforward installation and/or removal of the metering device by means of an ROV (or downline assisted by ROV). Attention should be paid to minimize external features that could hinder accessibility, or snag tether and control lines during an ROV operation. It is also important to design the package so as to provide appropriate ROV "grab points." The design should permit the operator unfettered access to control and instrumentation lines (flying leads). The operator should also take account of the available tools for ROV intervention to ensure

that components can be operated and also that they cannot be overloaded and damaged by such interventions.

During installation it is desirable to be able to test parts of the system during the process of going in, especially the hydraulic integrity of the system. Secondary considerations are flowmeter submerged weight, methods of submerged weight control (if warranted), and the overall impact of submerged weight on operating stresses on associated structures, and on installation and retrieval.

Although not required, the use of a design which permits easy exchange of primary sensors within a metering system by ROV rather than retrieving the entire system is viewed favorably.

The design of the metering system should be such that it can be easily depressurized prior to removal, without damaging in any way the sensors or other parts of the meter.

6.4.10 Stresses Due to Environmental Conditions.

The design envelope for meters must take into account the wide range of conditions which will include the following.

6.4.10.1 Handling, Lifting and Installation. Loads due to stresses generated during these operations should be accounted for.

6.4.10.2 Thermal Effects. Thermal stresses, due to extremes from installation to operation to remediation, should be analyzed and accounted for in the piping and instrumentation systems. While construction and fabrication may occur in ambient temperatures of 100°F, produced gas may reach operating temperatures in excess of 300°F, subsea temperatures approach 32°F, and the Joule-Thompson effect across the subsea chokes can drop the production temperature down to -20°F. The thermal range should also take account Joule-Thompson effects which may be generated by depressurization during hydrate remediation.

6.4.10.3 Pressure. Operators must consider internal pressure ranges from the low of atmospheric at installation to the maximum, which will usually be the pipeline hydrostatic test pressure, as well as external hyperbaric pressure at subsea depth.

6.4.10.4 Hydrodynamic Loading. Hydrodynamic loading on subsea meters and their associated pipework may be significant. The attached flowlines and piping may attract current and wave induced loads that lead to high moments in the piping and flanges, especially where dynamic amplification could occur. Unusual profiles and features on equipment should be considered for the potential for complications due to currents, (e.g., during hurricanes). In cases of potentially high current velocity, care should be taken to ensure that vortex shedding is considered and mitigated by design. Vortex induced vibration (VIV), can lead to fatigue failures and must be considered, especially in jumper mounted meter installations.

Extreme loads can be applied to equipment as it is lowered into the splash zone at installation. Dynamic Application Factors with and without the metering system included shall be calculated for such situations.

6.4.10.5 Impact Loading. During installation, large loads can be applied to the equipment as it is landed in place subsea and when subsequent connections are made to it for supporting equipment. The connector hub installation rigging and resulting loads must be considered.

Impact loading is a significant design case for meters which will only be inspected by ROV. The meter package may be governed by the design for ROV intervention and the associated potential impact loads. The design should also use the package structure to protect the sensors, piping and cables

6.4.11 Collapse. An analysis shall be made of the possibility of collapse of any pressure-bearing sections of the metering system in all phases—installation, operation, remediation, etc.

6.4.12 Other Factors. Some other design considerations of which an operator should be cognizant are listed here.

6.4.12.1 Sensor Accuracy. Sensor accuracy and maximum allowable drift relative to overall meter measurement accuracy for the required operating range should be addressed when sensors are being proposed or specified.

6.4.12.2 Power Requirements. Power demand from sensors relative to available power budget should be addressed early in the system selection process.

6.4.12.3 Mechanical Protection. Consideration should be given the potential for damage to flow meters during their operating life. Provision for appropriate and adequate protection from mechanical damage cause by ROV, dropped objects, or other should be given consideration.

6.4.12.4 Software Development. There exists a need to develop, field install, and test appropriate flow meter algorithms. Appropriate (desired) units, mass and volumetric flow rate, and measurement reporting requirements and format should all be addressed.

API RP 17A should also be used as a guide for transportation, handling, installation, hook-up, commissioning, maintenance and abandonment of subsea equipment.

6.5 INSTALLATION EFFECTS ON MEASUREMENT

It is well known that flow meter readings are affected by layout, dimensions, and any internal obstructions in the pipe-work upstream of the meter. The applicant must demonstrate that these installation effects have been taken into account, based on the best information available from the manufacturer and on accepted industry knowledge and practice.

6.6 ADDITIONAL TESTING ON MEASUREMENT SYSTEMS

In addition to Meter Calibration, Factory Acceptance Testing, and Meter Component Testing, prior to actual operation of subsea meters, certain other testing must be done to insure correct function. Typical of these tests are:

6.6.1 Systems Integration Test (SIT). Systems Integration Test is where two or more pieces which are to be connected subsea are fit together on land to insure proper function prior to installation underwater. It is recommended for metering systems and their associated pipework.

6.6.2 Installation Demonstration. This can also be described as a “wet test,” in which access and handling by ROV in tanks is demonstrated.

6.6.3 Software Testing. The operator should test all flow meter software to verify correct algorithm output against a variety of selected known inputs and outputs. Other aspects which need to be tested to assure quality are the ability of all systems to recover from interrupts (e.g., power outage, computer lockup, etc.) and the ability of the operator to remotely download software “patches” or improvements.

6.7 ROUTINE VERIFICATION

It is essential that an active campaign of verification be an integral part of the routine operation of the field production.

Prior to approval by regulatory authorities and partners to use wet gas meters subsea, the applicant must declare what will be done to verify the correct operation of the meters as an ongoing, routine procedure. In this Verification Plan, a number of variables will be identified, including the following.

6.7.1 Comparison of Redundant Sensors. A source of information when verifying the performance of the measurement system is the collection of sensors which are used. Since at least one level of redundancy must be present, it will be useful to gather data on the readings observed on the sensors relative to one another.

In the case of deepwater and harsh environments, it may prove cost effective to install additional transducers, which can be introduced into the measurement system by “software” methods.

6.7.2 Monthly System Balance Check. This is the test most likely to be used as the primary verification tool. This first level of system auditing compares the Master Quantity with the sum of the Individual Theoretical Quantities (see Section 5). The difference between the two over a pre-defined period of time, called the System Balance, should lie within an error range defined by the uncertainties due to the subsea meters, to the reference meters, and to the equation-of-state and transport methodologies used. It should be performed on both the primary product (gas) and secondary products (liquids)

to verify that measurement of both phases is within tolerance. More frequent balance checks are encouraged when used for diagnostic or other purposes.

Perhaps the most difficult part of the System Balance Check is the setting of thresholds and defining of criteria for declaring the system out of balance. This is challenging for two reasons. The first is that the elimination of systematic errors must have been done well, or these will tend to skew the imbalance analysis. The second is that differences in relative production levels through meters may tend to mask a failure, (i.e., a hard failure in a minimal producer may be hard to detect), and may resemble a marginal failure in a high producer. For these reasons, it will be necessary to look at many parameters in combination with the System Balance to determine the overall health of the system. More details on the System Balance Check are found in Section 7.

It must be noted that for secondary products, due to the very small volumes of liquids anticipated in developments which use wet gas flow metering, the overall inaccuracies for these components may be relatively high.

6.7.3 Sensor Zero and Offset Check at Shut-in.

There will be occasions, scheduled and otherwise, when the individual wells will have their production shut in. Most governing and regulatory bodies require regular testing of well equipment. The operator should ensure that these regular tests are used to verify the zero-offset and calibration of the sensors as part of an agreed program of verification.

6.7.4 Other Recommended Diagnostics. What has been recommended here is potentially a small part of the overall diagnostic capability available to the user who tries to ascertain the performance of his measurement system and the devices which comprise it. Certain new technologies to be offered for wet gas measurement in the future may be able to completely diagnose their own performance through extensive diagnostic measurements and calculations. Where these are available, they should be identified in the application.

6.8 OPERATION OUTSIDE CALIBRATED ENVELOPE

It is not unlikely that occasionally the conditions in which a previously calibrated meter is operating will change to the extent that it is operating outside the envelope inside which it had originally been calibrated. In this instance, the operator must carefully examine the overall system balance and any other evidence, then make a determination as to whether there is any indication that the meter is performing improperly. If there is reason to believe that such a condition exists, steps must be taken to either (a) remedy the problem or (b) justify why no action should be taken.

A possible remedy is the testing of a so-called *proxy* meter, (i.e., a meter with identical dimensions and other characteristics to the operational meter, but which can be readily shipped

to a calibration facility for testing in the extended operational range not originally covered). New calibration data extending the range would then be gathered and installed on the original meter.

7 Abnormal Operations

7.1 CONTINGENCY PLAN

An integral part of the operating strategy is a Contingency Plan for dealing with an Abnormal Condition in the measurement system. Abnormal Conditions in measurement are defined as those situations when malfunctions in the measurement chain cause the processes for allocation of gas and liquid hydrocarbon production to err. This can either be malfunctions of the hardware, or not using the appropriate software to calculate the gas and liquid flow rates. There are three aspects to an Abnormal Condition which must be considered, namely how the Abnormal Condition will be (a) detected, (b) verified, and (c) acted upon. These are discussed in greater detail below.

As an aid to both the applicant and the approval body, it is recommended that the applicant flow chart the process which is developed for their Contingency Plan.

7.2 DETECTION OF ABNORMALITY (NORMAL-ABNORMAL BOUNDARY DEFINITION)

There are two basic methods for detection of an Abnormal Condition. The first is by observing the System Balance of both gas and liquid, defined in Section 5 as the difference between the Master Quantity (reference meter readings) and the sum of the Individual Theoretical Quantities (sum of individual contributing meters, corrected for pipeline packing and possible phase transformation). The second is by observing the characteristics of individual contributing meters. Each of these will be discussed in what follows.

7.2.1 System Balance Check. Comparing the measurements from subsea meters with readings from topside reference meters is a logical means of detecting an Abnormal Condition. It is, however, not without peril. One potential pitfall is the possibility that systematic errors are incorporated in the meter's readings. This will not only cause economic problems when allocating production, but may suggest a meter malfunction when one does not exist. A second is that differences in relative production levels through meters may tend to mask failures. Thus a hard failure in a minimal producer may be hard to detect, and may resemble a marginal failure in a high producer. For these reasons, it will be necessary to look at many parameters in combination with the System Balance to determine the overall health of the system.

It is important to consider the System Balances of both the gas and liquid phases. However, for very dry gas it will likely become more difficult to use balance in the liquid measure-

ment, due to the large relative uncertainties in these cases. Fortunately, in these cases of Category 1 wet gas, as defined in Section 2, the mass flow rate of the liquids is so small that this is not an issue of great concern.

As shown in Equation (E.1) of Appendix E, the uncertainty of the calculated System Imbalance can be written as

$$E\{I^2\} = \sigma_z^2 + \sum_1^n \sigma_i^2$$

where σ_i^2 reflect the physical conditions of the reference meter. If we set the Imbalance Limit that is used to trigger an alarm condition at twice the standard deviation of the System Imbalance (95% confidence level), then

$$\begin{aligned} T_I &= 2\sigma_I \\ &= 2\sqrt{\sigma_z^2 + \sum_1^n \sigma_i^2} \end{aligned}$$

For gas measurement, comparing the System Imbalance with this Imbalance Limit will routinely be done, normally at a frequency which coincides with the accounting period, or monthly, whichever is shorter. For liquid measurement, the System Imbalance will ordinarily be calculated, but only for Category 2 Wet Gas will the use of an Imbalance Limit be required.

The Imbalance Limit described above is properly called a *Specified Imbalance Limit* in contrast to an *Imbalance Upper/Lower Control Limit*. The Specified Imbalance Limit is determined by considerations such as contractual obligations and/or regulatory requirements. Imbalance Upper/Lower Control Limits indicate to those responsible for the process that something has changed and needs to be investigated. Unlike the Specified Limits, the Imbalance Upper/Lower Control Limits are fixed after some history has been gained on how the process performs "typically."

7.2.2 Individual Meter Characteristics. In addition to looking at the measurement system as a whole, it should be possible to observe the qualities of and quantities from individual meters, and therefrom detect an Abnormal Condition.

A primary way to do this is through the use of redundant sensors as described in 6.7.1.

In another example, the drift of any one set of transducers can be detected for the case of constant choke settings, since the flow should remain effectively constant, provided the well head pressure is constant and the pressure drop across the choke is large enough that the flow is critical (sonic).

These examples assume subtle failures of sensors, whereas experience shows many failures will be more obvious, such as a complete loss of signal, leading to a more straightforward identification of the system fault.

7.3 INVESTIGATION (VERIFICATION OF ABNORMALITY, IDENTIFICATION OF CAUSE)

If the imbalance is detected and there is an obvious cause, such as a failed meter or sensor, the operator should immediately revert to an alternative measurement scheme such as those listed under that heading below. Furthermore, if possible the onset of failure should be identified and the alternative measurement should be used to backfill data to that point in time.

In the case where there is no obvious failure of a meter or sensor which could be the cause of the System Balance problem, it is important to use all means available to identify the root cause of the Imbalance. Listed below are some strategies for this attempt.

7.3.1 *Verify that reference meters are measuring correctly.* Before overlooking the obvious, a thorough inspection of the topside reference meters should be made.

7.3.2 *Verify proper conversion between the subsea and reference measurements.* Are PVT packages applied correctly, are temperature and pressure measured correctly, and is the right composition used to convert the subsea measurements to the topside measurements?

7.3.3 *Test by absence, shutting in each well sequentially.* This can be done to identify the culprit, but a complete cycle through all meters should be done in case there is more than one faulty meter. It should be carefully considered how representative such a test is. With this method, longer tieback distances may be a problem, as well as small well counts due to the effect on production.

7.3.4 *Other testing by absence.* It may be faster to develop strategies for shutting in groups of wells to identify the cause of imbalances.

7.3.5 *Verify zero readings on all meters and transmitters during shut-in.* This could be further evidence of a faulty transmitter or meter. This shall be the standard operating procedure, the measurement system should have capability to identify and mask any drift in the zero reading. Note that drift of the span cannot be detected during the shut-in.

7.3.6 *Observe secondary product balance for clues to failure source.* The balance and composition of the gas or liquids could suggest solutions.

7.3.7 *Compare readings from redundant sensors.* It should be helpful to compare the outputs of redundant sensors for change. Rather than looking only at instantaneous readings, however, one should look at their difference over time to determine if there has been a significant departure from the “norm” since the System Imbalance was detected.

7.3.8 *Other diagnostic parameters.* Individual meter sensors have their own characteristic signals, the monitoring of which may indicate the malfunction of a meter. As an exam-

ple, meters which use gamma-ray densitometry can monitor voltage levels which indicate the health of their scintillation detectors. Changes in these signals might point to a failure.

7.3.9 *Observe evidence of other well parameters (e.g., Bottomhole and Wellhead Pressure & Temperature).* Changes in these parameters (or lack thereof) can confirm or contradict what is being observed on the meter for an individual well, thus can be an important tool in investigating meter failures.

7.3.10 *Compositional Analyses.* There may be clues which can be derived from observing the composition of the composite stream and comparing it with “normal” as well as with the compositions of the individual wells, especially with regard to the heavier components. This technique has been used with success in traditional multiphase problems through the technique called Geochemical Fingerprinting.

7.3.11 *SCADA System Malfunction.* The performance of the Supervisory Control and Data Acquisition system should be examined for the possibility that errors emanate there.

7.4 REMEDIAL ACTION

Once the investigation is complete, an appropriate method of alternative measurement should be used, both for future measurement as well as working back to when proper measurement ended. Determining what are acceptable alternatives is required as a part of the Contingency Plan, and also should be included on the Flow Chart if that approach is taken.

Alternative measurement must be approved by the Governing Regulatory Body.

Some alternative measurement methods are described below.

7.4.1 Dual-DP Meters. For dual-DP devices, using either DP meter as “back-up” if the other fails is an acceptable remedial action.

7.4.2 Calibrated Choke. By measuring differential pressures across the chokes while the subsea meters are yielding good data for gas and liquid flow rates, in normal conditions this information can be used to “calibrate” the choke. The choke may then be used as a backup device if the primary meter is lost. It is recommended that this approach be used only in the case where the meter has failed totally (i.e., it has failed at the primary level, as well as in all backup modes).

If this approach is to be taken, it is important to record all choke data on a routine basis, in order to characterize its response as completely as possible. Transmitters should be re-zeroed whenever the well is shut in (at least quarterly), and a record of choke sensor readings versus meter sensor readings should be maintained for use as a calibration record. The planned frequency of calibration must be specified in the Governing Regulatory Body application if this approach is planned for use as a back-up. It is recommended that the user

perform quarterly re-calibrations versus the primary device, which corresponds with mandatory quarterly wellhead shut-in testing. This form of measurement may be used for a period of up to six months as a meter substitute.

If there is any erosion of the choke or changes in fluid properties, its calibration would change, thereby requiring periodic re-calibration, or periodic changes in uncertainty values based on the date of the last calibration.

7.4.3 Other Transmitters. It may be that other sensors can be substituted which are less accurate, (e.g., DP cells with a different measurement range). While this may reduce the measurement accuracy, it might be useable until a scheduled intervention.

7.4.4 Last Value Stand-in Proxy. The last known good measurements for the specific pressure and temperature may be used for a maximum of 60 days.

7.5 IF ALL ELSE FAILS

Intervention is recommended within 60 days if no other measurement means is available. Otherwise, any alternative can be used without limits as long as producer, commingled partners, purchaser, and Governing Regulatory Body agree on the measurement uncertainty level for this alternative.

8 Template for Wet Gas Permit Application

An integral part of the process of applying Uncertainty-based Allocation to Commingled Wet Gas streams is the application for permission to do so from the Governing Regulatory Body. What follows is a template, or “roadmap,” which can be used by an applicant to consolidate all the requisite information which that authority requires.

8.1 PROJECT IDENTIFICATION

8.1.1 Project Name

8.1.2 Lease Description

8.1.3 Partners

8.1.4 Operators

8.1.5 Producer Representatives, Areas of Responsibility

8.2 PROCESS DESCRIPTION

Explain the flow of produced hydrocarbons into and through the commingling facilities, from the individual wells through the host platform. Use simplified diagrams to show pipeline segments, production equipment, and the allocation and reference (sales) meters.

Information on each well’s characteristics should be supplied, not just for startup conditions, but for projected conditions over the life of the field. Some of these are:

- Range of Flow Rates, Pressures, Temperatures, Gas/Liquid Volume Fractions, and Lockhart-Martinelli Parameters Anticipated.
- Composition, Water Volume Fraction, Fluid Properties. How Determined.
- Category 1 or Category 2 Wet Gas.

8.3 MEASUREMENT DEVICES

8.3.1 Allocation Meters. Data on each kind of meter to be used on individual streams, (e.g., manufacturer, principle, sizing, planned installation pipework, evidence of expected uncertainty performance in the application).

8.3.2 Reference Meters. Data on the kinds of meters to be used for sales/reference of gas and all liquids to be measured. Manufacturer, principle used, sizing, data which demonstrates its applicability in current application, evidence of expected uncertainty performance in the application.

8.3.3 Liquid Measurement. Explanation of how liquid hydrocarbon flow rates will be measured or estimated, evidence of expected uncertainty performance in the application.

8.4 PRE-INSTALLATION METER TEST PLANS

8.4.1 Flow Testing of Allocation Meters. Facility. Ranges of flow rates, pressure, temperature, and fluid composition/properties. If extrapolation of measurement range is planned, why is this acceptable?

8.4.2 Component Tests. Sensors, electronics, pressure on meter body.

8.4.3 Factory Acceptance Testing (FAT)

8.4.4 Plan for Flow Testing Reference Meters. Facility. Range of flow rates.

8.5 OPERABILITY CONSIDERATIONS

8.5.1 Pressure Analysis. What pressures inside and outside the pipe are expected over the field life?

8.5.2 Hydrate Susceptibility. Hydrates anticipated? Severity? Measures to be taken.

8.5.3 Sensor Redundancy. Show how redundant sensors will be used.

8.5.4 Installability/Removability. How will the meters and instrumentation be removed if this is necessary?

8.5.5 Stress Analysis. Demonstrate that consideration has been given to the effects of stresses due to pressure, temperature, handling, installation, hydrodynamic forces, and installation.

8.5.6 Sample Taking. How will a sample be recovered if this is necessary?

8.6 Verification Plan. What will be the manner in which proper measurement operation will be verified.

8.7 Contingency Plan. What is the plan for detection, verification, and remediation of fault conditions?

8.8 Details of Allocation Procedure. Discuss the Allocation Philosophy for the project, and how the principles fostered in this recommended practice are to be applied.

8.9 Regulatory Compliance. Discuss the manner in which compliance will be achieved. For projects on the U.S. Outer Continental Shelf (OCS), the applicable regulations are found in the Code of Federal Regulations, Title 30, Sub-part L, "Oil and Gas Production Measurement, Surface Commingling, and Security."

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APPENDIX A—UNCERTAINTY DETERMINATION AND THE APPLICATION OF EQUATIONS OF STATE

When the readings from the reference meters are to be allocated back to the contributing wells, it is required that all measurements be transformed to a common environmental state so that an equitable distribution of the *System Imbalance* can be made. A PVT Analysis in which Equations of State are applied is a common method of doing this. It should be noted that, while these methods are clearly applicable in these and other similar problems, their use is not without peril. The results obtained are only as good as the fit to the problem at hand, and will actually add uncertainty to the final result.

Referring to Figure A.1, a subsea measurement is made of the pressure P_s , temperature T_s , and gas and liquid mass flow rates Q_{gs} and Q_{ls} through a meter. Knowledge of the composition of the fluids flowing through the meter is assumed. The fluids then pass through a pipeline and possibly other devices (e.g., valves, separators, etc.), after which they are again measured by reference meters on a platform, at pressure P_p , temperature T_p , at gas and liquid mass flow rates Q_{gp} and Q_{lp} . Again, knowledge of the composition of the fluids flowing through the reference meter is assumed.

In order to apply the methods developed above for allocation based on uncertainties in measurement for each meter, it is necessary to know the uncertainties for both the subsea and reference measurements at a common set of environmental conditions. The most straightforward way of doing this is if the uncertainties in subsea measurement are translated to the conditions of metering at the platform. However, since it is likely that phase transformations have taken place in the various flowing components—some gas will have become liquid, and vice versa—this will not generally be a trivial task.

A final assumption that should be made is that the entire system is in a steady-state condition, (i.e., the flow rates of all components are constant, as are pressure, temperature, and composition both subsea and on the platform).

Two approaches to this normalization of uncertainties will be considered. One is to develop the mathematical expressions for the measurement uncertainties of the subsea meters, based on transforming their errors using the equations of state (EOS) applied to the readings of the meters. A second approach, which will probably be easier to apply for complex metering systems, is the use of so-called Monte Carlo techniques to establish the required uncertainties. Each of these will be considered.

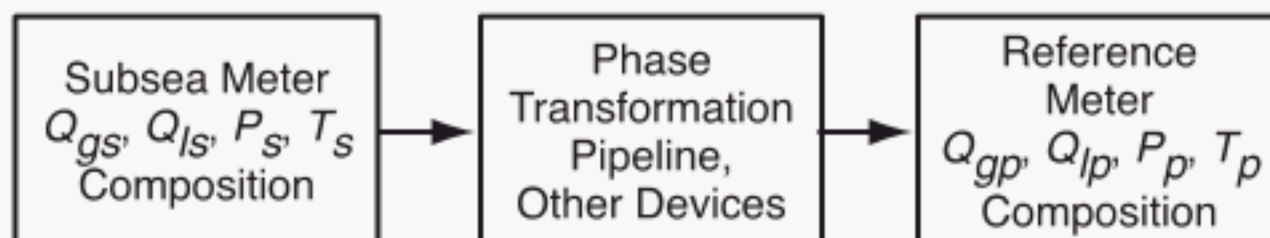


Figure A.1—Schematic of Fluid for PVT Analysis

We consider the mass of the gas in terms of the moles and molecular weights of the N individual components. These can be related by

$$m_g = n_g^1 \cdot MW_1 + n_g^2 \cdot MW_2 + \dots + n_g^N \cdot MW_N \quad (A.1)$$

where n_g^i and MW_i represent the moles and molecular weight of the i^{th} component of the gas. We know the relative abundance of the constituents of the gas and liquid at the subsea meter in terms of the mole fractions x_g^i of each of the components, so

$$n_g^i = x_g^i \cdot n_g$$

therefore

$$m_g = n_g \cdot (x_g^1 \cdot MW_1 + x_g^2 \cdot MW_2 + \dots + x_g^N \cdot MW_N) \quad (A.2)$$

$$m_g = n_g \cdot \sum_{i=1}^N x_g^i \cdot MW_i$$

$$m_g = n_g \cdot MW_g \quad (A.3)$$

Thus we have expressed the mass m_g of the gas in terms of the moles n_g and average molecular weight MW_g it represents. Similarly, for the liquids measured at the meter

$$m_l = n_l^1 \cdot MW_1 + n_l^2 \cdot MW_2 + \dots + n_l^N \cdot MW_N \quad (A.4)$$

$$m_l = n_l \cdot (x_l^1 \cdot MW_1 + x_l^2 \cdot MW_2 + \dots + x_l^N \cdot MW_N) \quad (A.5)$$

$$m_l = n_l \cdot MW_l \quad (A.6)$$

If we now consider the mass flow rates for gas and liquid, we can express these as

$$\dot{m}_g = \dot{n}_g \cdot (x_g^1 \cdot MW_1 + x_g^2 \cdot MW_2 + \dots + x_g^N \cdot MW_N) \quad (A.7)$$

$$\dot{m}_l = \dot{n}_l \cdot (x_l^1 \cdot MW_1 + x_l^2 \cdot MW_2 + \dots + x_l^N \cdot MW_N) \quad (A.8)$$

The molar flow rates of the i^{th} components of gas and liquid are

$$\dot{n}_g^i = x_g^i \cdot \dot{n}_g \quad (A.9)$$

$$\dot{n}_l^i = x_l^i \cdot \dot{n}_l \quad (A.10)$$

Further, the molar flow rates on both a component and total fluid basis can be written as the sum of the gas and liquid parts, i.e.,

$$n = \dot{n}_g + \dot{n}_l \quad (\text{A.11})$$

$$\dot{n}^i = \dot{n}_g^i + \dot{n}_l^i \quad (\text{A.12})$$

We observe from Equations (A.9) and (A.10) that the uncertainties in component molar flow rates are due to the uncertainties in either total molar gas and liquid flow rates \dot{n}_g and \dot{n}_l or the mole fractions x_g^i and x_l^i . Equations (A.7) and (A.8) relate the molar flow rates of the components to the measurement of gas and liquid mass flow rate coming from the meter. The mole fractions, though not known perfectly, must be assumed to be correct, since they cannot be measured during normal operation, hence the uncertainties in molar flow rates are directly related to the mass flow uncertainties.

When in the steady state, not only should the total mass and (total) molar flow rates be the same at both subsea and topside metering points, but the molar flow rates of the individual components should be constant as well. For example, the sum of gas and liquid propane measured at the subsea meter must equal the sum of gas and liquid propane measured topside. However, since it is entirely likely that there will be phase changes between the gas and liquid for individual components, some of what was measured as gas or liquid at the subsea meter—with its attendant uncertainty—will be measured in the other state topside. Thus, in order to properly account for these phase changes, the PVT analysis must identify what fraction of the subsea molar flow rate of gas and liquid components are converted to gas and liquid flow topside. This must be done both for the gas and liquid measurements on a component basis, as the phase changes will differ for the various components. Liquid components measured subsea, some of which will be converted to gas by the time topside conditions have been reached, are reduced by the factor α_i in the process. Likewise, if gas is converted to liquid it will be reduced from that measured subsea by a factor of β_i . In mathematical form we can write these relationships as

$$\begin{bmatrix} \dot{\tilde{n}}_l^1 \\ \dot{\tilde{n}}_l^2 \\ \vdots \\ \dot{\tilde{n}}_l^N \end{bmatrix} = \begin{bmatrix} 1-\alpha_1 & \cdot & \cdot & 0 \\ 0 & 1-\alpha_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & 1-\alpha_N \end{bmatrix} \begin{bmatrix} \dot{n}_l^1 \\ \dot{n}_l^2 \\ \vdots \\ \dot{n}_l^N \end{bmatrix} + \begin{bmatrix} \beta_1 & \cdot & \cdot & 0 \\ 0 & \beta_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & \beta_N \end{bmatrix} \begin{bmatrix} \dot{n}_g^1 \\ \dot{n}_g^2 \\ \vdots \\ \dot{n}_g^N \end{bmatrix} \quad (\text{A.13})$$

and for the gas flow

$$\begin{bmatrix} \dot{\tilde{n}}_g^1 \\ \dot{\tilde{n}}_g^2 \\ \vdots \\ \dot{\tilde{n}}_g^N \end{bmatrix} = \begin{bmatrix} 1-\beta_1 & \cdot & \cdot & 0 \\ 0 & 1-\beta_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & 1-\beta_N \end{bmatrix} \begin{bmatrix} \dot{n}_g^1 \\ \dot{n}_g^2 \\ \vdots \\ \dot{n}_g^N \end{bmatrix} + \begin{bmatrix} \alpha_1 & \cdot & \cdot & 0 \\ 0 & \alpha_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & \alpha_N \end{bmatrix} \begin{bmatrix} \dot{n}_l^1 \\ \dot{n}_l^2 \\ \vdots \\ \dot{n}_l^N \end{bmatrix} \quad (\text{A.14})$$

These are shown schematically in Figure A.2. If we use Equations (A.9) and (A.10), then

$$\begin{bmatrix} \dot{\tilde{x}}_l^1 \\ \dot{\tilde{x}}_l^2 \\ \vdots \\ \dot{\tilde{x}}_l^N \end{bmatrix} \dot{\tilde{n}}_l = \begin{bmatrix} 1-\alpha_1 & \cdot & \cdot & 0 \\ 0 & 1-\alpha_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & 1-\alpha_N \end{bmatrix} \begin{bmatrix} x_l^1 \\ x_l^2 \\ \vdots \\ x_l^N \end{bmatrix} \dot{n}_l + \begin{bmatrix} \beta_1 & \cdot & \cdot & 0 \\ 0 & \beta_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & \beta_N \end{bmatrix} \begin{bmatrix} x_g^1 \\ x_g^2 \\ \vdots \\ x_g^N \end{bmatrix} \dot{n}_g \quad (\text{A.15})$$

and

$$\begin{bmatrix} \dot{\tilde{x}}_g^1 \\ \dot{\tilde{x}}_g^2 \\ \vdots \\ \dot{\tilde{x}}_g^N \end{bmatrix} \dot{\tilde{n}}_g = \begin{bmatrix} 1-\beta_1 & \cdot & \cdot & 0 \\ 0 & 1-\beta_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & 1-\beta_N \end{bmatrix} \begin{bmatrix} x_g^1 \\ x_g^2 \\ \vdots \\ x_g^N \end{bmatrix} \dot{n}_g + \begin{bmatrix} \alpha_1 & \cdot & \cdot & 0 \\ 0 & \alpha_2 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot \\ 0 & \cdot & \cdot & \alpha_N \end{bmatrix} \begin{bmatrix} x_l^1 \\ x_l^2 \\ \vdots \\ x_l^N \end{bmatrix} \dot{n}_l \quad (\text{A.16})$$

Equations (A.15) and (A.16) thus relate the gas and liquid molar flow rates at topside conditions to those at the subsea point where the measurement is made. Using the relationships of Equations (A.7) and (A.8) with (A.15) and (A.16) we should be able to express the uncertainties of the subsea allocation meters at topside conditions.

In what has been discussed above, only a single application of EOS has been shown. In reality, it is likely that application of EOS will be required several times in addition to the transition from subsea to topside (e.g., with HP and LP separators, dehydration units, compressors, and other points where pressure or temperature might change between the points where the allocation and reference measurements are made). Using the methodology developed above, each of these changes can be dealt with to determine uncertainties of the allocation meters at reference meter conditions.

Even though what has been shown here points one in the proper direction by which to obtain the uncertainties required, for large and complex systems which are most often prevalent, these methods may be both tedious and difficult. To avoid these complications and gain other benefits, it may be attractive for the user to consider using a simulation tool to model the system's uncertainties. A method which has found considerable success in many areas similar to this is the Monte Carlo technique.

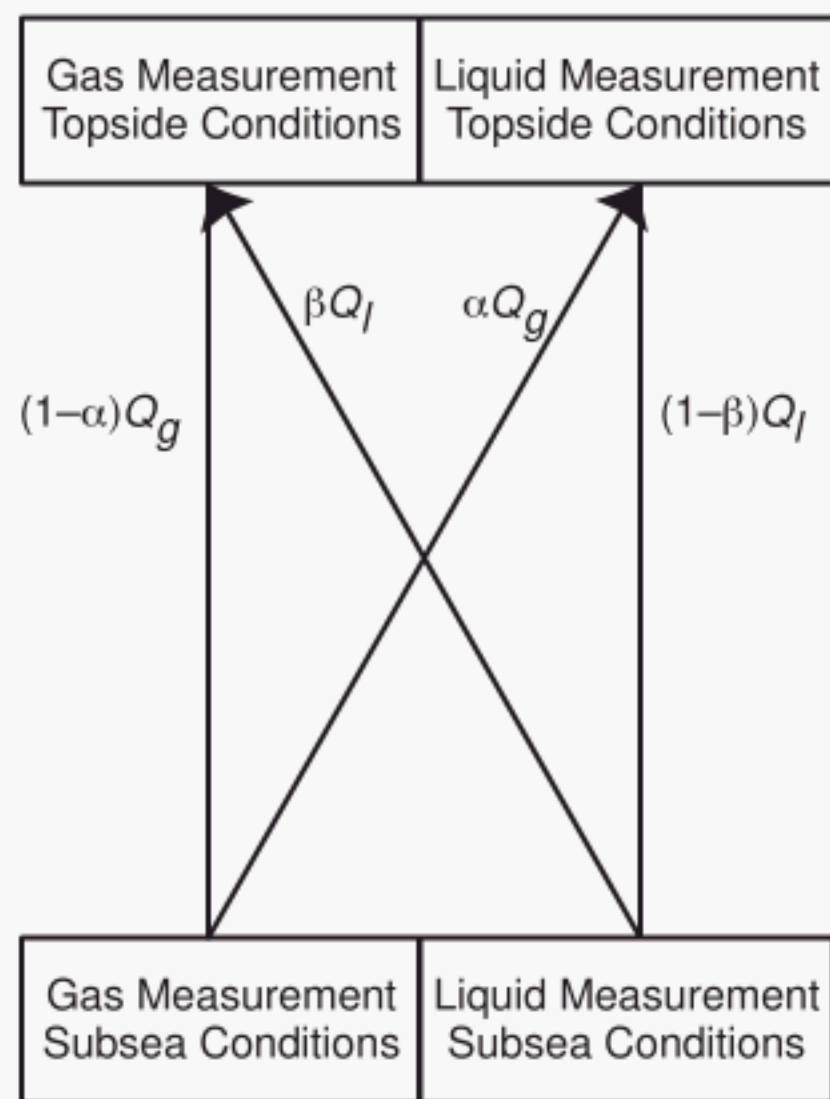


Figure A.2—Illustration of Fluid Phase Change Between Subsea and Topside

In using Monte Carlo simulation methods, one models the system with all its subsea meter errors, its reference meter errors, as well as errors in sensors such as pressure and temperature that are used to transform the phases from subsea conditions to those of the reference meter. Then, random

inputs are created in all measurements using random number generation routines, the data are processed through the model (which includes the EOS), and the results are compiled for a very large number of such random trials. Once the “game” has been played a sufficiently large number of times, one can create probability distributions based on the samples collected. For very complex systems such as these, this is often the best means of determining the parameters needed, (i.e., variances, systematic measurement errors, and so on).

It should be recognized that the resultant uncertainties in the transformed allocation meter readings come from three sources. The first is the uncertainty in the measurement that is made by the subsea meter and subsequently transformed by the EOS to reference meter conditions. The second is the uncertainty due to inaccuracies in the inputs used in the transformation from subsea to reference meter conditions, (e.g., pressure and temperature measurements either subsea or at the platform), and the fluid composition at the subsea meter. Finally, the equations of state provide a transformation that only approximates the real world, so there will be inaccuracies in its application. These can and should be modeled in order to assess the relative impact of each on the total uncertainty.

The use of Monte Carlo simulation methods in analyzing the uncertainties in measurement systems is described in some detail in Basil and Jamieson, 1998 (see Section 2).

APPENDIX B—EVALUATING UNCERTAINTY

It should be clear that the key element in applying this Uncertainty-based Allocation (UBA) is the accurate determination of uncertainty at every point in the system where measurements are made. What follows is a discussion of the basic concepts of measurement uncertainty, and is largely taken from Reference 2, the International Organization for Standardization (ISO) *Guide to the Expression of Uncertainty in Measurement*. There is a companion publication of the same name by the American National Standards Institute (ANSI), which is simply a duplication of the ISO document. For a more comprehensive treatment of the topic of Measurement Uncertainty, the interested reader is referred to either of these documents.

Uncertainty is defined here as a characterization of the dispersion of the measurement of a *measurand* from its *true value*. The *measurand* is the particular quantity subject to measurement. By *true value* is meant the underlying characteristic of the measurand which would be recorded if the measurement were perfect, (i.e., there were no measurement errors). An *error* is the difference between the result of a measurement and the *true value* of the *measurand*. *Errors* are the source of *uncertainty*, so characterizing *uncertainty* means understanding the nature of the *errors* in a measurement system.

Errors can be characterized as either *random errors* or *systematic errors*. A *systematic error* is the difference between the mean value of a measurement and its true value, generally a constant or near-constant value. A *random error* is the error which deviates about the mean value of the measurement in an unpredictable, bipolar (equally likely plus or minus values) fashion.

There are certain parameters which are useful in characterization of uncertainty. The *mean value* of a measurement is the result one would obtain if a measurement were made an infinite number of times and the arithmetic average of the measurements were calculated. The *variance* of a measurement is the expected value of the square of the difference between the measurement and its mean value. The term *expected value* is used in a probabilistic sense. The *standard deviation* of a measurement error is the square root of its *variance*.

In the absence of knowledge of a meter's performance in a specific situation, it is useful to perform measurements to obtain statistical values of parameters such as systematic error, standard deviation, and variance. The *sample (experimental) variance* is defined as

$$\sigma_z^2 = \frac{1}{n-1} \cdot \sum_1^n (z_i - \bar{z})^2 \quad (\text{B.1})$$

where the *sample mean* is \bar{z}

$$\bar{z} = \frac{1}{n} \cdot \sum_1^n z_i \quad (\text{B.2})$$

Thus, the sample variance gives an indication of the dispersion of the measured data about the mean value based on the n samples which are recorded.

It is often of more use to deal with the standard deviation rather than the variance, since the units of the former are the same as those of the quantity being measured. The sample standard deviation is defined as the square root of the sample variance, or

$$\sigma_z = \sqrt{\frac{1}{n-1} \cdot \sum_1^n (z_i - \bar{z})^2} \quad (\text{B.3})$$

Two other important concepts in this domain are the *repeatability* and the *reproducibility* of the measurement. *Repeatability* of measurement results is defined as the closeness of the agreement between results of successive measurements of the same measurand carried out under the same conditions of measurement. Thus, a test of repeatability would be measurements made by the same observer, using the same procedure, with the same instrument(s), at the same location, repeated over a short period of time. *Reproducibility* of measurement results is defined as the closeness of agreement of measurement results of the same measurand carried out under changed conditions of measurement, such as different location, time, reference standard, etc. Both *repeatability* and *reproducibility* of measurement are important factors.

Sometimes a quantity which is not the measurand will affect the result of measurement. Such a quantity is called an *influence quantity* or *influence factor*. If their effect is significant, it will probably be advantageous to measure these *influence factors* and to attempt to correct the measurement to reduce the error. This corrected measurement is sometimes called an *estimate*.

In the case of Subsea Wet Gas Meters, uncertainties due to both the systematic and random errors should be identified in the flow lab tests that are required. Flow lab tests are used to calibrate the meters against gas and liquid reference meters in order to develop calibration curves. The act of determining these curves should remove most of the systematic error in the meter. Furthermore, by making several measurements at identical conditions of flow and environmental parameters, one can characterize the random error in measurement that can be expected at those conditions. This can take the form of a sample standard deviation as described above, which then allows an uncertainty envelope to be developed over the oper-

ating wet gas range of the meter. Other influence quantities besides liquid content should also be varied in the flow lab tests, such as pressure, temperature, velocity, and fluid properties, (e.g., water volume fraction, salinity, viscosity, and density). These effects should also be incorporated in the composite operating uncertainty envelope. Shown below are typical calibration data which might result from flow lab tests. The data point dispersion shows errors due to the presence of liquids, in addition to the basic uncertainty of the meter in measuring gas with no liquids present.

In this example the primary error is random (not systematic) as a result of liquid loading on the meter. Plotted in Figure B.2 are the mean of the samples at various values of GVF, and the envelope of random uncertainty plotted about this mean. The mean represents the systematic offset (error) that

now can be considered as “calibrated out,” while the envelope gives the values to be used in Uncertainty-based Allocation.

By removing the systematic error and applying this uncertainty in the allocation process, equity can be achieved between different meters operating at distinctively different uncertainties within the same allocation system. By applying these calibration results to the wet gas meter output, the majority of system systematic error should be eliminated. However, by routinely monitoring the system balance trend, any other system systematic errors may be determined and further removed from the system. This can be done by carefully applying an additional factor, which in effect adjusts the calibration curve. As in all cases, careful study must be given to adjusting for systematic offset in the system over time, to ensure that the conditions likely to cause this offset are still prevalent and of the same magnitude.

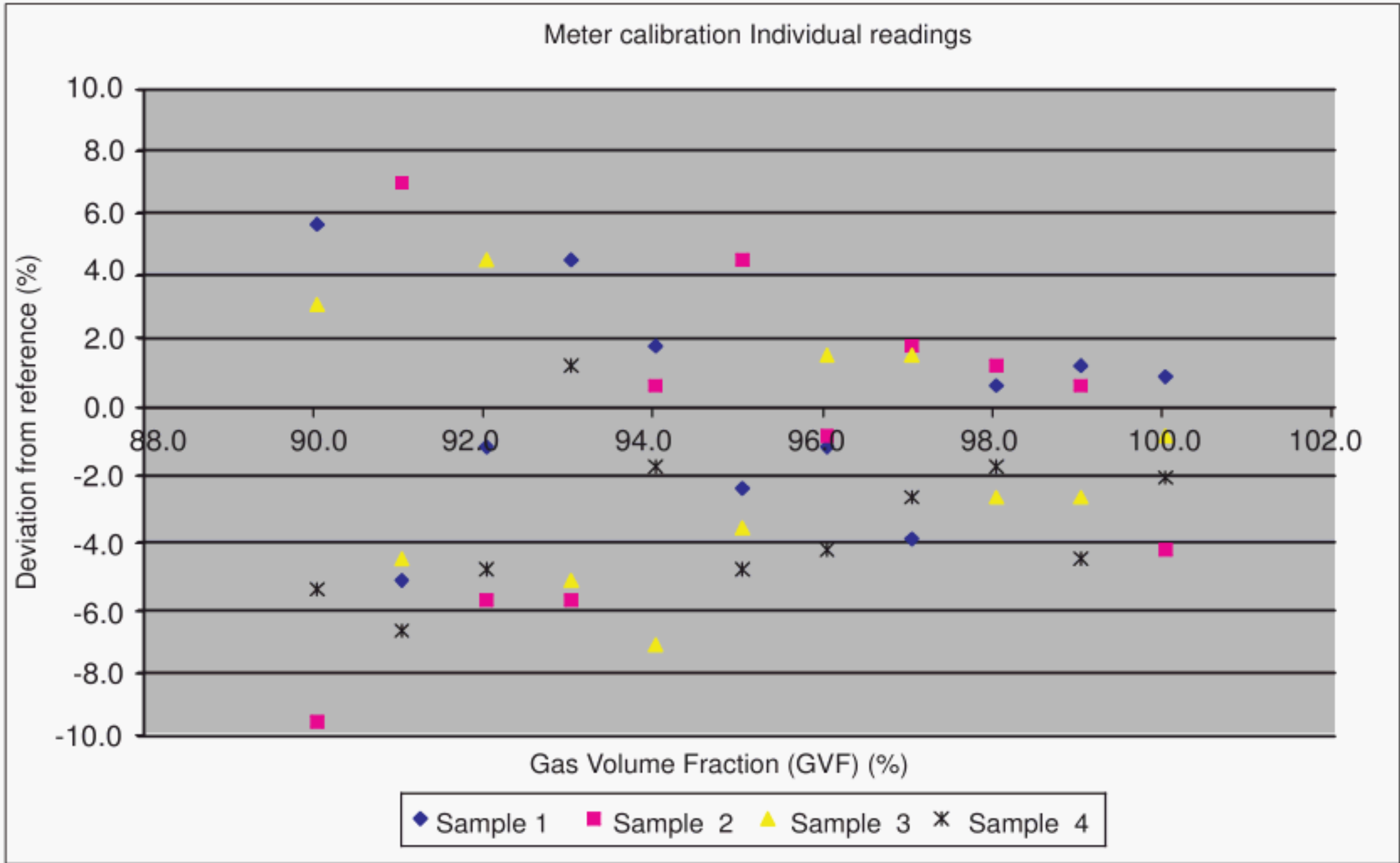


Figure B.1—Typical Flow Calibration Results

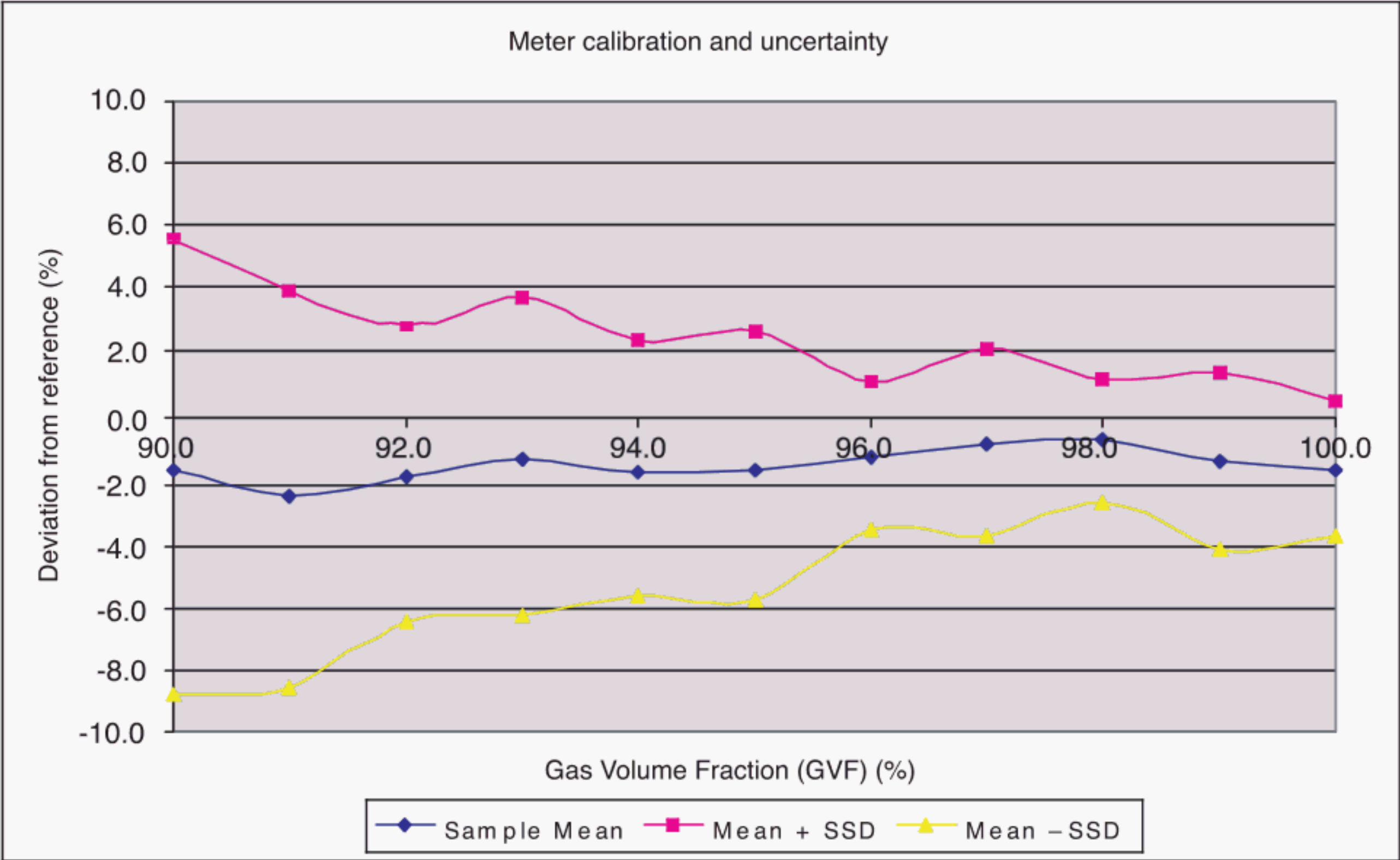


Figure B.2—Uncertainty Curve Resulting from Flow Calibration of B.1

APPENDIX C—WORKED EXAMPLE OF UNCERTAINTY-BASED ALLOCATION

C.1 Example

Reference Meter (Master) Quantity (Q_z) = 21.50 kg/sec

Reference Meter Uncertainty = 1.00%

Well 1 Theoretical Quantity (Q_1) = 5.0 kg/sec
Meter 1 Uncertainty = 5.00%

Well 2 Theoretical Quantity (Q_2) = 5.0 kg/sec
Meter 2 Uncertainty = 2.50%

Well 3 Theoretical Quantity (Q_3) = 6.5 kg/sec
Meter 3 Uncertainty = 4.00%

Well 4 Theoretical Quantity (Q_4) = 5.5 kg/sec
Meter 4 Uncertainty = 1.80%

C.2 Solution

Determine the sum of the theoretical quantities based on gas measurement at each individual meter:

$$\sum_1^n Q_i = 5.0 + 5.0 + 6.5 + 5.5 = 22.0 \text{ kg/sec}$$

Calculate the system imbalance:

$$I = Q_z - \sum_1^n Q_i = 21.50 - 22.00 = -0.50 \text{ kg/sec}$$

Determine each meter's uncertainty in throughput and its variance:

Reference Meter

$$\sigma_z = Q_z \times 1.0\% = 21.50 \times 0.01 = 0.215 \text{ kg/sec}$$

$$\sigma_z^2 = (0.215 \times 0.215) = 0.046225 (\text{kg/sec})^2$$

Well 1

$$\sigma_1 = Q_1 \times 5\% = 5.00 \times 0.050 = 0.25 \text{ kg/sec}$$

$$\sigma_1^2 = (0.25 \times 0.25) = 0.0625 (\text{kg/sec})^2$$

Well 2

$$\sigma_2 = Q_2 \times 2.5\% = 5.00 \times 0.025 = 0.125 \text{ kg/sec}$$

$$\sigma_2^2 = (0.125 \times 0.125) = 0.015625 (\text{kg/sec})^2$$

Well 3

$$\sigma_3 = Q_3 \times 4\% = 6.50 \times 0.040 = 0.26 \text{ kg/sec}$$

$$\sigma_3^2 = (0.26 \times 0.26) = 0.0676 (\text{kg/sec})^2$$

Well 4

$$\sigma_4 = Q_4 \times 1.8\% = 5.50 \times 0.018 = 0.099 \text{ kg/sec}$$

$$\sigma_4^2 = (0.099 \times 0.099) = 0.009801 (\text{kg/sec})^2$$

Determine total uncertainty in throughput variance, recalling that meter errors are independent (uncorrelated) random variables:

$$\sum_1^n \sigma_i^2 = 0.0625 + 0.015625 + 0.0676 + 0.009801 = 0.155526 \text{ kg/sec}$$

Calculate uncertainty allocation factor for each meter:

$$\alpha_i = \frac{\sigma_i^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} + \frac{Q_i}{\sum_{j=1}^n Q_j} \cdot \frac{\sigma_z^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2}$$

$$\text{Well 1 } \alpha_1 = 0.36186$$

$$\text{Well 2 } \alpha_2 = 0.12952$$

$$\text{Well 3 } \alpha_3 = 0.40276$$

$$\text{Well 4 } \alpha_4 = 0.10586$$

Calculate the allocated quantity for each well

$$A_i = (Q_i + (I \cdot \alpha_i))$$

$$\text{Well 1 } A_1 = (5.00 + ((-0.50) \times 0.36186)) = 4.819 \text{ Kg/sec}$$

$$\text{Well 2 } A_2 = (5.00 + ((-0.50) \times 0.12952)) = 4.935 \text{ Kg/sec}$$

$$\text{Well 3 } A_3 = (6.50 + ((-0.50) \times 0.40276)) = 6.299 \text{ Kg/sec}$$

$$\text{Well 4 } A_4 = (5.50 + ((-0.50) \times 0.10586)) = 5.447 \text{ Kg/sec}$$

Totalize allocated quantity per well to verify equality with reference meter quantity:

$$Q_z = 21.50 \text{ kg/sec}$$

$$\sum_1^n A_i = 4.819 + 4.935 + 6.299 + 5.447 = 21.50 \text{ Kg/sec}$$

Thus

$$\sum_1^n A_i = Q_z$$

APPENDIX D—MONTHLY UNCERTAINTY DETERMINATION

It is required that the System Imbalance be allocated back to the contributing meters at a frequency which coincides with the accounting period, or monthly, whichever is shorter. The flow rates of hydrocarbon gas and liquids will not be constant during this period, nor will the uncertainty be constant. How then can the meter's throughput and uncertainty be computed for the period in question?

If we look at the diagram in Figure D.1, the flow rate for the larger period has been broken into a series of N "time slices," each of duration T , so that the complete measurement period is NT . For any meter, T will be the so-called integration time over which a single reading will be output. Dependent on the particular technology used, T may range from a fraction of a second to several minutes. The quantity Q measured during NT is simply the sum of the measured Q_i during each time slice.

$$Q = Q_1 + Q_2 + \dots + Q_N = \sum_i^N Q_i \quad (D.1)$$

We can also write an equation expressing the total meter uncertainty for the complete measurement period NT as:

$$E\{(Q - \bar{Q})^2\} = E\{(Q_1 - \bar{Q}_1)^2 + (Q_2 - \bar{Q}_2)^2 + \dots + (Q_N - \bar{Q}_N)^2\} + E\{\text{cross-products}\} \quad (D.2)$$

where Q is the total flow for the period NT , \bar{Q} is the true value of the flow, and Q_i is the flow measured during the i^{th} time period. If the N measurements are stochastically independent and any systematic measurement errors have been eliminated, then the expected values of the cross-products are zero. Thus

$$\{(Q - \bar{Q})^2\} = E\{(Q_1 - \bar{Q}_1)^2\} + E\{(Q_2 - \bar{Q}_2)^2\} + \dots + E\{(Q_N - \bar{Q}_N)^2\} \quad (D.3)$$

$$E\{(Q - \bar{Q})^2\} = \sigma^2 = \sigma_1^2 + \sigma_2^2 + \dots + \sigma_N^2 \quad (D.4)$$

Thus for the period NT , a flow $Q = \sum_i^N Q_i$ is measured with an accuracy of $\sigma = \sqrt{\sum_i^N \sigma_i^2}$.

As one might expect, the summation of the individual quantities should have an averaging effect on the measurement quality. The improvement suggested by this analysis is a reduction in the standard deviation of the error by \sqrt{N} .

However, it is clear that in actual practice one cannot drive the measurement uncertainty to zero simply by combining the

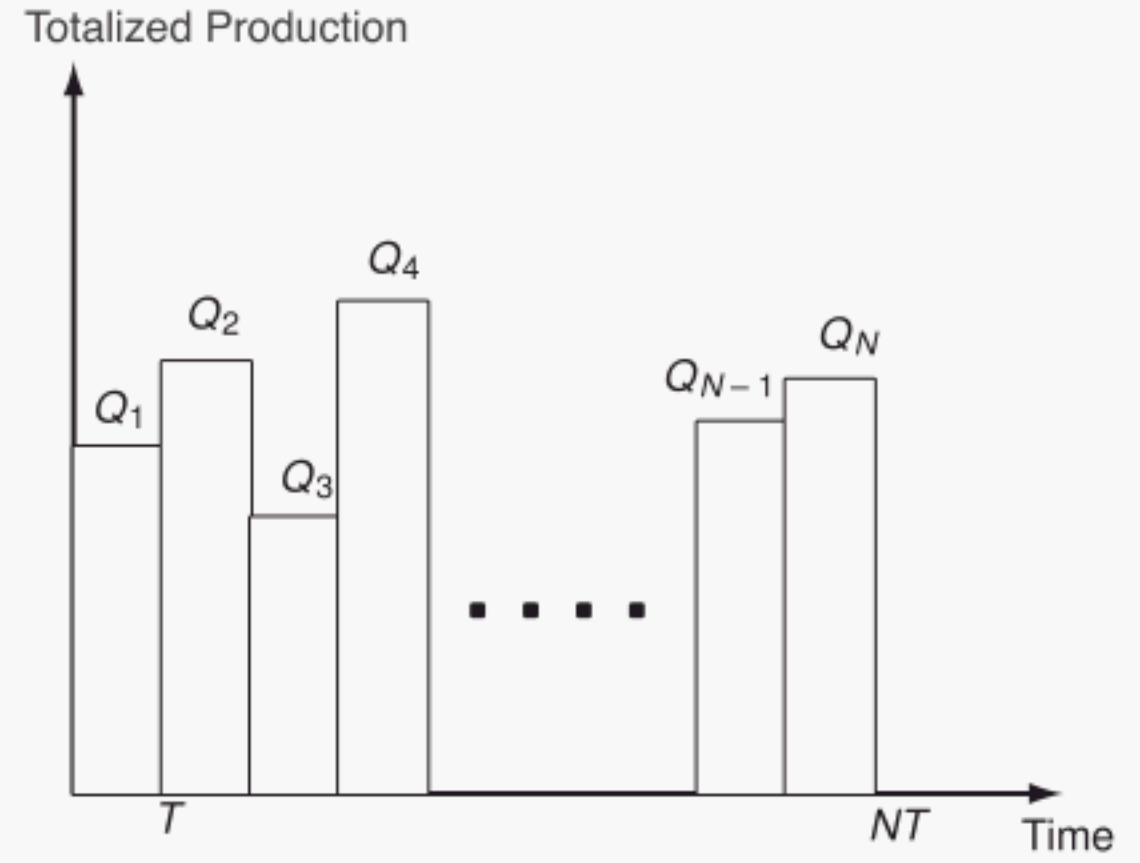


Figure D.1—Illustration of Combining "Time-slice" Production Data

estimates over a long enough period. While there may be numerous reasons why this isn't so, the most clearly obvious is the fact that systematic errors are difficult to eliminate, and often return once in service due to operational causes, such as calibration drift, corrosion/erosion of meter body or components, and the like.

In the following, the effects of an undetected bias in measurement on the readings of a single meter are examined. Assume that in measuring the quantity Q , which has a true value of \bar{Q} , there exists an undetected bias in measurement, such that

$$Q_i = \bar{Q}_i + \epsilon_i + \delta$$

Thus the measurement is the sum of the true value, a zero-mean measurement error ϵ_i , and a systematic error, or bias. Furthermore, for the sake of simplifying this analysis, assume that δ is a constant offset that is independent of the magnitude of Q_i . Then Equation (D.2) becomes

$$E\{(Q - \bar{Q})^2\} = E\{(Q_1 - \bar{Q}_1)^2 + (Q_2 - \bar{Q}_2)^2 + \dots + (Q_N - \bar{Q}_N)^2\} + E\{(Q_1 - \bar{Q}_1) \cdot (Q_2 - \bar{Q}_2) + (Q_1 - \bar{Q}_1) \cdot (Q_3 - \bar{Q}_3) + \dots + (Q_{N-1} - \bar{Q}_{N-1})(Q_N - \bar{Q}_N)\} \quad (D.5)$$

$$\begin{aligned} &= E\{(\epsilon_1 + \delta)^2 + (\epsilon_2 + \delta)^2 + \dots + (\epsilon_N + \delta)^2\} \\ &\quad + E\{(\epsilon_1 + \delta) \cdot (\epsilon_2 + \delta) + (\epsilon_1 + \delta) \cdot (\epsilon_3 + \delta) + \dots + (\epsilon_N + \delta)(\epsilon_{N-1} + \delta)\} \end{aligned} \quad (D.6)$$

Since

$$E\{\varepsilon_i \cdot \delta\} = E\{\varepsilon_i\} \cdot E\{\delta\} = 0$$

$$\begin{aligned} \{(Q - \bar{Q})^2\} &= (\sigma_1^2 + \delta^2 + \sigma_2^2 + \delta^2 + \dots + \sigma_N^2 + \delta^2) \\ &\quad + N \cdot (N-1) \cdot \delta^2 \end{aligned} \quad (D.7)$$

Thus

$$E\{(Q - \bar{Q})^2\} = \sum_1^N \sigma_i^2 + N^2 \cdot \delta^2 \quad (D.8)$$

It can be seen that this last Equation (D.8) becomes Equation (D.4) in the absence of any systematic error. In contrast to this earlier result where no bias existed, the uncertainty of the estimate is now bounded by the size of the systematic error δ . As N grows very large, the second term will dominate the expression, so that in the limit the standard deviation is simply $N\delta$.

In point of fact, truth may lie somewhere between these two extremes. It is generally true that monthly balances are

better than daily balances, daily are better than hourly, etc. So, although perfection will not be achieved, there is good reason to average the data over time, doing one's best to identify and eliminate systematic errors.

The above analysis can be applied to sum individual readings into hourly measurements, to sum hourly measurements into daily totals, or to sum daily totals into monthly totals. It should be obvious that nothing in this derivation requires that the individual samples be made consecutively, so there should be no problem in dealing with periods when data is lost, the meter was not operable, or the well was not flowing. However, since during these periods the flow cannot be described as steady-state, other premises assumed here may be violated unless care is taken.

It is important that the quantity T , (i.e., the basic measurement integration period used by the meter), should in practice be the same integration period as that which was used when flow calibration of the meters was performed at the reference facility. Otherwise, it is possible that the uncertainty figures used in the calculation are incorrect. It is a straightforward exercise to re-calculate the uncertainties in order to reconcile them to the parameters used during flow calibration.

APPENDIX E—UNCERTAINTY-BASED ALLOCATION— DERIVATION OF OPTIMAL FACTORS

Returning to the allocation example shown in Figure 1, consider first the case where only two streams are commingled. The streams through the meters M_1 and M_2 are commingled and subsequently measured by a high-accuracy meter M_z . For the purpose of simplifying the equations, let the readings from M_1 and M_2 be x_1 and x_2 , and that from M_z be z . We can write each as the sum of a true value term and an error term,

$$\begin{aligned}x_1 &= \bar{x}_1 + \varepsilon_1 \\x_2 &= \bar{x}_2 + \varepsilon_2 \\z &= \bar{z} + \varepsilon_z = x_1 + x_2 + \varepsilon_z\end{aligned}$$

Here we make the assumption that any systematic errors have been eliminated during the calibration of the meters, so that the errors in x_1 , x_2 , and z are zero-mean random variables with (measured) characteristic variance σ_1^2 , σ_2^2 , and σ_z^2 . Furthermore we assume that the errors in measurement of the three streams are independent, (i.e., a measurement error in M_1 is unrelated to a measurement error in M_2), and neither is related to a measurement error in the meter M_z .

We can write the equation for the imbalance I as:

$$\begin{aligned}I &= z - (x_1 + x_2) \\&= \varepsilon_z - \varepsilon_1 - \varepsilon_2\end{aligned}$$

The variance of the imbalance is then:

$$\begin{aligned}E\{I^2\} &= E\{(\varepsilon_z - \varepsilon_1 - \varepsilon_2)^2\} \\&= \sigma_z^2 + \sigma_1^2 + \sigma_2^2\end{aligned}$$

For the more general case of n allocation meter inputs this becomes:

$$E\{I^2\} = \sigma_z^2 + \sum_1^n \sigma_i^2 \quad (\text{E.1})$$

In the example of two streams, let the fractional part of the imbalance assigned to M_1 be called α_1 , that assigned to M_2 will be α_2 , which is $(1 - \alpha_1)$. We then write

$$\begin{aligned}I_1 &= \alpha_1 \cdot I \\I_2 &= \alpha_2 \cdot I = (1 - \alpha_1) \cdot I\end{aligned}$$

so that the production allocated to each stream (Individual Allocated Quantity) is:

$$\begin{aligned}A_1 &= x_1 + I_1 = x_1 + \alpha_1 \cdot I \\A_2 &= x_2 + I_2 = x_2 + (1 - \alpha_1) \cdot I\end{aligned}$$

We now want to calculate the errors which result from allocating production in this way. The ultimate goal of this exercise is to choose the allocation factors α_1 , and α_2 in such a way as to minimize the error, or more precisely, the mean-square-error. This method of optimization is called *least-mean-square (LMS) minimization or optimization*.

$$\begin{aligned}E_1 &= A_1 - \bar{x}_1 = \varepsilon_1 + \alpha_1 \cdot I \\&= \varepsilon_1 + \alpha_1 \cdot (\varepsilon_z - \varepsilon_1 - \varepsilon_2) \\&= (1 - \alpha_1) \cdot \varepsilon_1 - \alpha_1 \cdot (\varepsilon_2 - \varepsilon_z)\end{aligned}$$

and

$$\begin{aligned}E_2 &= A_2 - \bar{x}_2 = \varepsilon_2 + (1 - \alpha_1) \cdot I \\&= \varepsilon_2 + (1 - \alpha_1) \cdot (\varepsilon_z - \varepsilon_1 - \varepsilon_2) \\&= \alpha_1 \cdot \varepsilon_2 - (1 - \alpha_1) \cdot (\varepsilon_1 - \varepsilon_z)\end{aligned}$$

The mean-square error of each of these is defined as the expected value of the square of the error E_1 or E_2

$$\begin{aligned}E\{E_1^2\} &= E\{[(1 - \alpha_1) \cdot \varepsilon_1 - \alpha_1 \cdot (\varepsilon_2 - \varepsilon_z)]^2\} \\&= (1 - \alpha_1)^2 \cdot \sigma_1^2 + \alpha_1^2 \cdot (\sigma_2^2 + \sigma_z^2)\end{aligned}$$

This last step follows directly from the fact that the measurement error terms in x_1 , x_2 , and z are stochastically independent random variables, so the expected values of their cross-products are zero. Likewise,

$$\begin{aligned}E\{E_2^2\} &= E\{[\alpha_1 \cdot \varepsilon_2 - (1 - \alpha_1) \cdot (\varepsilon_1 - \varepsilon_z)]^2\} \\&= \alpha_1^2 \cdot \sigma_2^2 + (1 - \alpha_1)^2 \cdot (\sigma_1^2 + \sigma_z^2)\end{aligned}$$

We now define the total mean-square error for the system as E_T , the sum of the mean-square errors of the two input streams,

$$\begin{aligned}E_T &= E\{E_1^2\} + E\{E_2^2\} \\&= (1 - \alpha_1)^2 \cdot \sigma_1^2 + \alpha_1^2 \cdot (\sigma_2^2 + \sigma_z^2) + \alpha_1^2 \cdot \sigma_2^2 \\&\quad + (1 - \alpha_1)^2 \cdot (\sigma_1^2 + \sigma_z^2) \\&= 2(1 - \alpha_1)^2 \sigma_1^2 + 2\alpha_1^2 \sigma_2^2 + \alpha_1^2 \sigma_z^2 + (1 - \alpha_1)^2 \sigma_z^2\end{aligned}$$

In order to find the value of α_1 which minimizes the mean-square-error of the system, one takes the derivative of E_T with respect to α_1 and sets the resulting expression to zero.

$$\begin{aligned} \frac{\partial E_T}{\partial \alpha_1} &= 4(1 - \alpha_1)(-1)\sigma_1^2 + 4\alpha_1\sigma_2^2 + 2\alpha_1\sigma_z^2 + \\ &\quad 2(1 - \alpha_1)(-1)\sigma_z^2 \\ &= 0 \end{aligned}$$

Solving for α_1 ,

$$\begin{aligned} 0 &= 2(\alpha_1 - 1)\sigma_1^2 + 2\alpha_1\sigma_2^2 + \alpha_1\sigma_z^2 + (\alpha_1 - 1)\sigma_z^2 \\ &= 2\alpha_1(\sigma_1^2 + \sigma_2^2 + \sigma_z^2) - 2\sigma_1^2 - \sigma_z^2 \end{aligned}$$

which becomes

$$\begin{aligned} \alpha_1 &= \frac{\sigma_1^2 + \sigma_z^2/2}{\sigma_1^2 + \sigma_2^2 + \sigma_z^2} \\ \alpha_2 &= 1 - \alpha_1 \frac{\sigma_2^2 + \sigma_z^2/2}{\sigma_1^2 + \sigma_2^2 + \sigma_z^2} \end{aligned}$$

It can be shown that extension of this methodology to the problem of n measured and commingled streams x_i which are then measured as a composite stream z yields:

$$\alpha_i = \frac{\sigma_i^2 + \sigma_z^2/n}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} \quad (\text{E.2})$$

which can be expressed as

$$\alpha_i = \frac{\sigma_i^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} + \frac{1}{n} \cdot \frac{\sigma_z^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} \quad (\text{E.3})$$

Consider the two terms in Equation (E.3). The first term assigns imbalance to the meter M_i according to its uncertainty relative to that of the other $(n - 1)$ meters used for allocation. The second term can be interpreted as the assignment of the effects of the reference meter uncertainty. Here this portion is divided equally among all the streams, irrespective of throughput. Assignment in this manner appears arbitrary, inconsistent with the desire that allocation be done fairly. An alternative formulation to counter this can be developed. Let the allocation factors defined by (E.3) be modified to distribute the reference meter uncertainty based on the relative throughput of each stream, with the result:

$$\alpha_i = \frac{\sigma_i^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} + \frac{Q_i}{\sum_{j=1}^n Q_j} \cdot \frac{\sigma_z^2}{\sigma_z^2 + \sum_{j=1}^n \sigma_j^2} \quad (\text{E.4})$$

Thus by using Equation (E.4), the uncertainty-based assignment of system imbalance will again be equitable (though perhaps not optimal), with imbalance due to reference meter errors assigned in a manner based on how much production flows through a meter run, rather than by simply dividing the total into n parts and assigning each stream an equal share.

APPENDIX F—WET GAS METER TECHNOLOGY

F.1 Overview

Although it has been needed for many years and its development has been pursued in the measurement community, the flow measurement of wet gas remains an elusive problem even today. The need is driven by those same kinds of situations which characterize the more general multiphase market, namely, cases where it is inconvenient, expensive, or impractical to separate the liquid and gas phases before measuring them with single phase flow meters.

Certainly the subsea petroleum production environment qualifies as a case where separation of oil, gas, and water is inconvenient, expensive, and in most cases impractical. If the wet gas flow rate is to be measured there, it will almost certainly be using a meter that is specially designed for operation in this difficult measurement domain.

The locations in the two-phase flow map where various flow regimes are most likely to occur are shown in Figure F.1. Clearly mist flow is a form of wet gas flow, as typically are annular and wavy flow. Stratified and slug flow may be borderline wet gas as it will be defined here.

What follows is a description of the history, state of the art, and possible future directions of wet gas flow meter development and usage. First considered are what shall be called “conventional” multiphase meters, which are aimed at applications in which the liquid volume fraction at actual conditions is relatively high. Next the history and use of the leading technique for wet gas flow metering, that of differential pressure devices, is described. When using differential pressure devices in wet gas, some knowledge of liquid flow rates is required, which is the subject of the next section. Next addressed is the use of dual differential meters to measure both liquid and gas rates concurrently. Finally, future trends are considered, (i.e., those other areas of research and development that may yield tomorrow’s wet gas measurement technology).

It should be emphasized that all observations contained in this Appendix are made for the world of measurement *only* as it exists in the year 2002.

F.2 Conventional Multiphase Meters in Wet Gas Measurement

A logical first step at measuring wet gas flowrates might be to try to extend the range of these conventional multiphase meters into the wet gas domain. Attempts to do this have generally met with failure. The reasons why they have failed can be understood by considering the physics of measurement in the most popular devices.

The multiphase meters commonly used measure the physical characteristics of the fluid in the pipe in order to determine its composition, most often the gamma-ray or x-ray attenua-

tion of the fluid, or its relative permittivity (dielectric constant).

In the literature there are numerous examples of meters which employ gamma-ray attenuation at multiple energies to determine composition, such as Olsen (Bibl. 14), Watt (Bibl. 21), Harrison (Bibl. 7), Scheers (Bibl. 15), and Segeral (Bibl. 16). The composition determination is accomplished by inverting a set of three or four equations, each of which describes the fluid gamma attenuation at a particular energy, as the fluid passes through the meter. The relative fractions of oil, gas, and water are the only unknowns, and solving for these parameters yields the fluid composition in the sensing area.

Other meters measure the dielectric constant of the fluid as it passes through the meter. Since the relative dielectric constant of water is significantly greater than that of other fluids, accurate measurement of this parameter gives a strong and measurable indication of the presence of water. Coupled with a density measurement (sometimes using a single-energy gamma-ray absorption densitometer) to indicate gas, one can make an estimate of the composition of the fluid in the pipe. The use of this technique to estimate composition has been described by Gaisford (Bibl. 6), Millington (Bibl. 12), and Mehdizadeh (Bibl. 11).

In addition to the composition measurement, velocity or flow rate measurement is usually made either with cross-correlation techniques (again using gamma absorption or dielectric constant measurements) or with Venturi devices.

What should be observed about both of these measurement methods is that the signal which is sensed by the meter and which is indicative of the composition of the fluid results primarily from the interaction of the stimulation mechanism—gamma rays in one case, electromagnetic energy in the other—with the *liquid* phase of the multiphase mixture. Unless the gas pressure is extraordinarily high, the gamma attenuation is due almost solely to the liquid present. Likewise, the response of electromagnetic sensors to variation in dielectric constant is due predominately to water in the liquid part of the mixture. Therefore it should be intuitive that the amount of material sensed for a stream at 99% Gas Volume Fraction (GVF) is only one-tenth as much as that sensed for a 90% GVF stream, and thus a significantly weaker signal is created.

F.3 Differential Pressure Devices for Wet Gas

In contrast to the case of traditional multiphase meters, the class of measurement devices called differential pressure devices is known to respond to variations in the density of the fluid being measured in a very sensitive manner. If the “wetness” of the gas is imagined as a variation in density, it can be seen that the liquid loading of the gas will cause an over-reading of the gas flow rate. Figure F.2 is an illustration of the

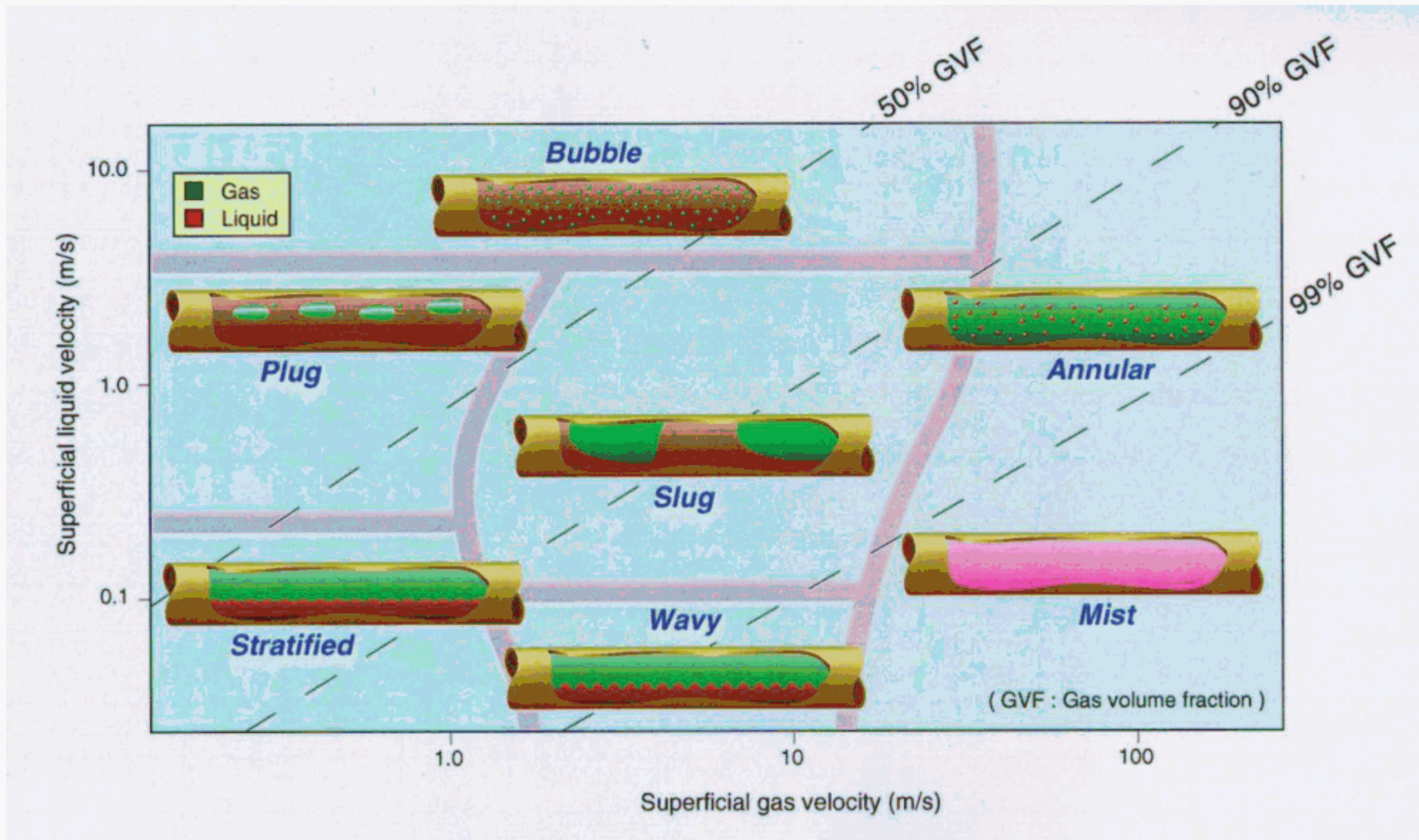


Figure F.1—Two-phase Flow Map Showing Approximate Locations of Various Flow Regimes with Respect to Liquid and Gas Flow Velocities for Horizontal Flow

effect. Research carried out over the last forty years has shown this phenomenon to be both systematic and predictable, given a device, fluid, and environmental conditions. This has formed the basis for a family of wet-gas meters which is the most widely used technology for this purpose worldwide in the year 2002.

Use of differential pressure devices for wet gas measurement continues to be popular, and research into this technology is active at a variety of organizations. In what follows, some contributions to this measurement technology are discussed. This list is not exhaustive.

F.3.1 Murdock, J.W. (Bibl. 13) Murdock is generally credited with having been the first to note the linear overreading of an orifice with liquid loading of the gas stream. The resulting curve (Figure F.2) is widely referred to as the “Murdock Correlation,” and is defined by Equation F.1.

$$Q_g = Q_{gi} \cdot (1 + MX)^{-1} \quad (\text{F.1})$$

where Q_g is the corrected gas flow rate, or “dry” gas flow rate, Q_{gi} is the indicated gas flow rate, M is the Murdock

coefficient (which he identified as 0.26), and X is the Lockhart-Martinelli parameter, defined in 1.1, Equation (1) as

$$X = \frac{Q_l}{Q_g} \cdot \sqrt{\frac{\rho_g}{\rho_l}} \quad (\text{F.2})$$

which can be re-arranged to

$$X = \frac{1-x}{x} \cdot \sqrt{\frac{\rho_g}{\rho_l}} \quad (\text{F.3})$$

where x is the gas mass fraction, and $\frac{\rho_g}{\rho_l}$ is the ratio of gas density to liquid density.

Murdock conducted his research using the orifice plate as his differential producer, and was primarily interested in measuring the flow of steam. His coefficient of 0.26 was derived from this case of steam and water in the liquid state.

F.3.2 Chisholm, D. (Bibl. 1) He is credited with refining the Murdock Correlation, developing an equation which is quite similar but with different parameters.

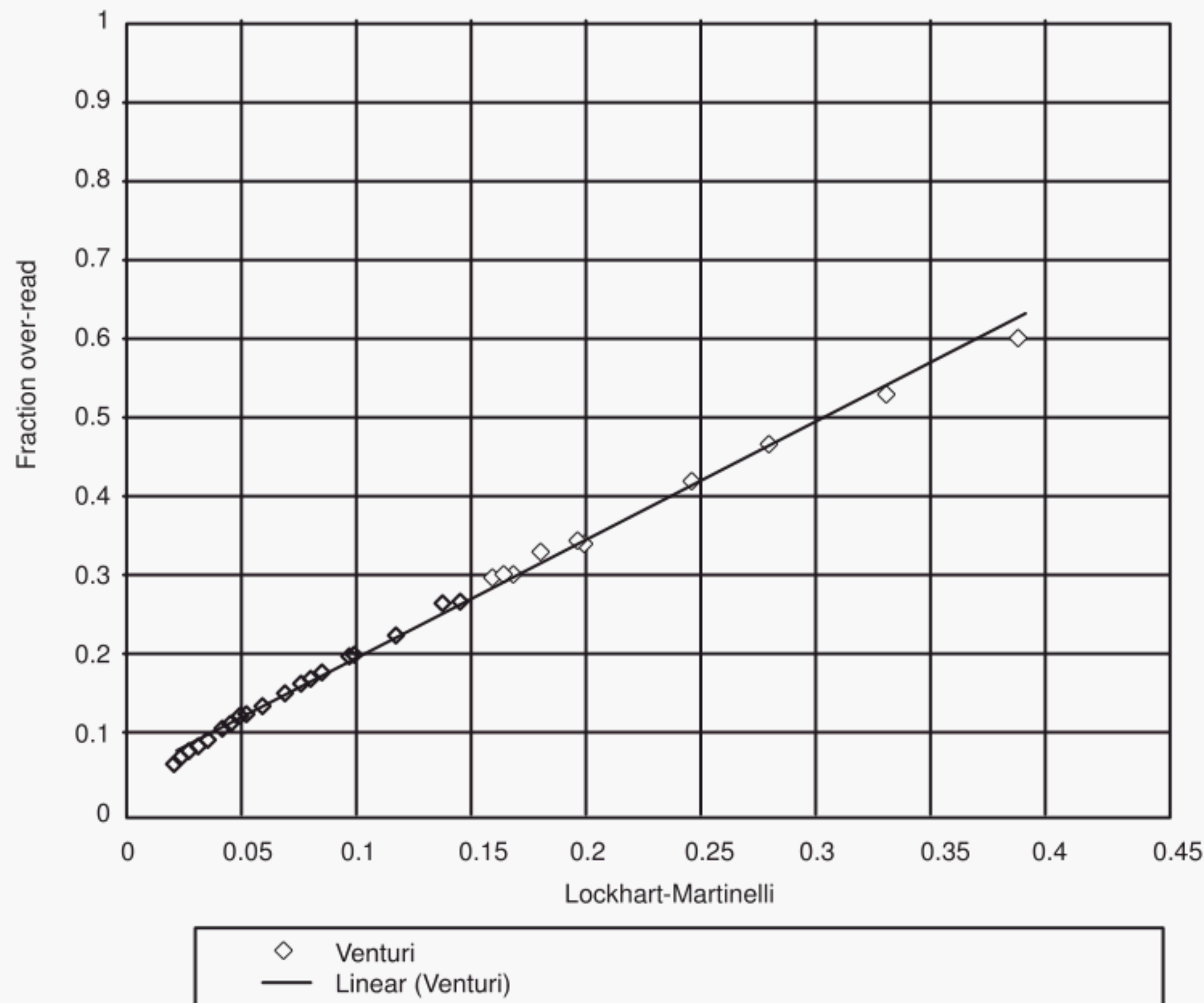


Figure F.2—Gas Over-reading by Venturi Meter as a Function of Lockhart-Martinelli Parameter

F.3.3 Shell. In the mid-1980's Shell conducted an extensive internal research and development program in the use of differential producers for wet-gas measurement. Much of their early testing was done in the NAM unit responsible for producing gas from the Groningen Field in The Netherlands. This early work was reported by G.V. Washington (Bibl. 20) at the North Sea Flow Measurement Workshop. Subsequent to this, A. Jamieson (Bibl. 9), R. de Leeuw (Bibl. 3, 4), H. van Maanen (Bibl. 19), and other Shell developers have reported on various improvements which have been made to the basic methodology of Murdock and Chisholm. Of particular interest is the first paper of de Leeuw (Bibl. 3) in which he demonstrated the pressure dependence of the Murdock Correlation, as shown in Figure F.3.

F.3.4 Couput, J.P. (Bibl. 2) TotalFinaElf has engaged in an extensive program of R&D in this area for several years, in concert with the French lab ONERA. Attempts to understand the effects of secondary parameters, (e.g., droplet size, Stokes number, droplet-film ratio, etc.), has been the major thrust of this work.

F.3.5 Fincke, J. (Bibl. 5) The device which resulted from this research, a special form of Venturi meter, was a by-product of nuclear-reactor flow measurement programs at the Idaho National Engineering Laboratory. It measures differen-

tial pressures in both the converging and recovery sections of the Venturi throat to estimate gas and liquid flow rates.

F.3.6 Annular Venturi. It has long been known that a Venturi-like response could be obtained with a differential producer consisting of an ordinary spool piece holding a rigid body in its center. Wet gas experiments have been carried out using a version of this device known as a V-Cone Meter (Ifft, Bibl. 8).

F.4 Liquid Flow Measurement

When using differential pressure devices for wet-gas flow rate measurement as practiced by users such as those listed above, a requirement is the input of some measure of the relative flow rates between gas and liquid. In applying the Murdock equations (F.1 – F.3) the gas mass fraction x must be known.

Perhaps the most widely used method for determining this input information is the so-called tracer dilution method, where tracers of a known concentration with a known flow rate are injected into the multiphase stream, and from samples taken at a considerable distance downstream of the injection point, again the concentration is measured. The primary reference for the method is a paper by de Leeuw (Bibl. 3). The

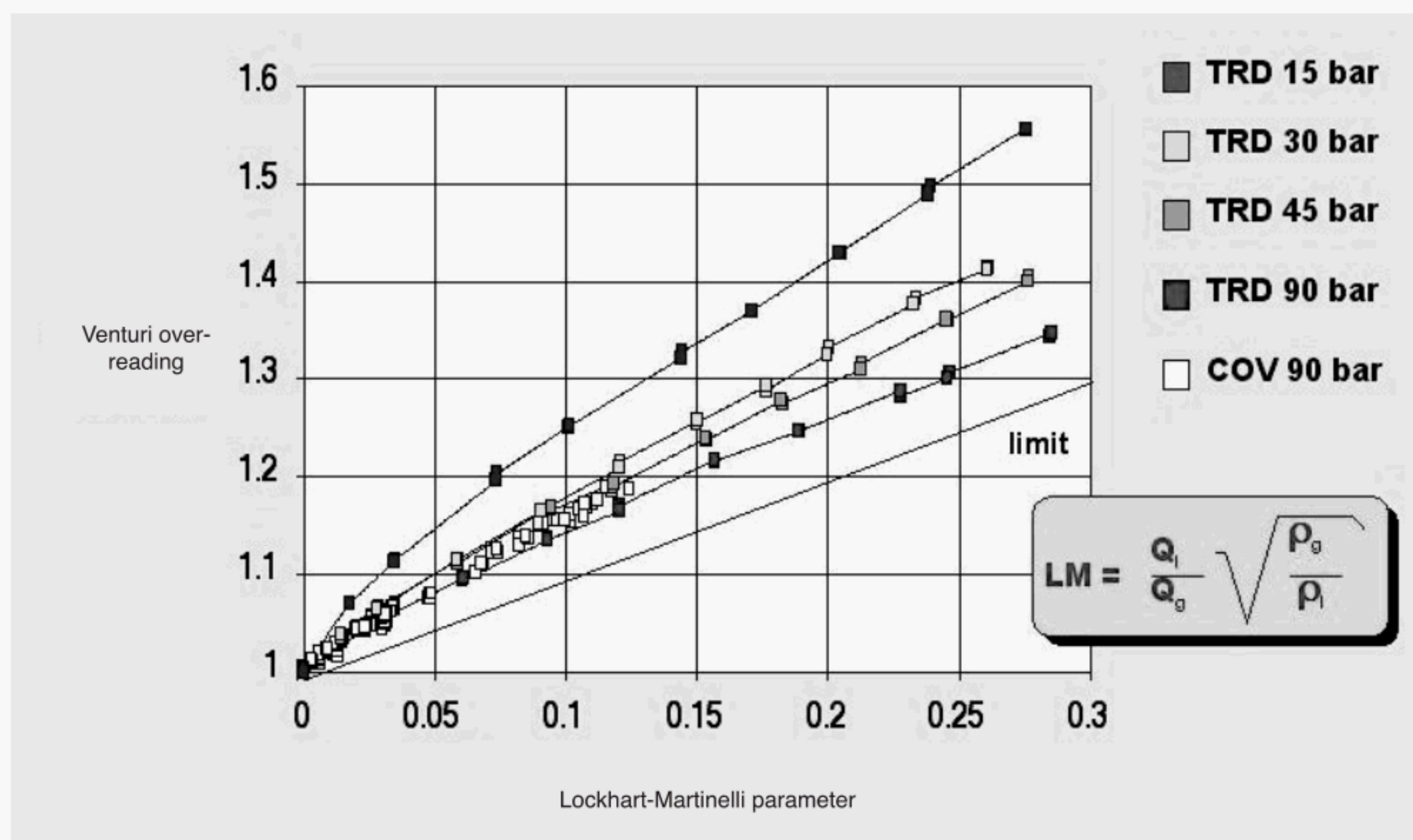


Figure F.3—Pressure Effect on Murdock Correlation (de Leeuw, Bibl. 3)

technique is largely manual in its application, though efforts are underway to automate the process.

Caution needs to be exercised relative to indirect liquid measurements, as this may (in part) include separate independent measurement of injected chemicals (e.g., methanol). The measurement error associated with the injection of such chemicals can on their own be very significant.

F.5 Dual Differential Measurement

During the late 1990's, British Gas Technologies developed a metering system in which the problem of measuring the gas (or liquid) mass fraction directly, without resorting to an indirect method such as tracer dilution, was addressed. The approach, reported by Tait (Bibl. 18), was to use two separate differential measurement devices which were geometrically dissimilar, and which thereby exhibited different over-reading correlation curves. When these characteristic curves are acquired and take the form of Equation (F.1), there are two characteristic slopes, M_1 and M_2 . Solving for the Lockhart-Martinelli parameter X permits the correction of Q_{gi} to the correct value Q_g , as well as provision of an estimate of the liquid flow rate.

Given the difficulty of determining the gas mass fraction in the subsea environment, this type of approach is potentially a large step forward in wet gas measurement there. It should be

pointed out, however, that these meters (1) only measure the *total* liquid passing through the meter, and (2) have difficulty accurately measuring low liquid flow rates (relative to gas flow rates).

F.6 Future Directions

Although differential pressure devices such as those described here are the technology of choice for subsea wet gas measurement circa 2002, there are other approaches and technologies under investigation which show promise and are herein discussed.

F.6.1 Ultrasonic. Gas ultrasonic flow meters have been studied for use in wet gas service for almost ten years. Projects UltraFlow I and UltraFlow II were Joint Industry Projects (JIPs) to determine if ultrasonic gas flow meters could survive in wet gas service conditions and provide useful measurements. JIP membership included many of the major operators in the North Sea. The key results were presented in a paper by M.B. Wilson (Bibl. 22) of BP at an NEL 1996 wet gas seminar, and at both 2000 and 2001 North Sea Flow Measurement Workshops by K. Zanker (Bibl. 23, Bibl. 24) who showed how gas and liquid flow rates might be measured for mist, annular, and stratified flow regimes over a range of flow rates and liquid loading.

In North America, Jepson (Bibl. 10) has described another method for measuring wet gas flows using multipath ultrasonic meters.

F.6.2 Joint Industry Projects. The measurement of wet gas has become an increasingly important topic in the petroleum industry, and the emergence of JIPs which are directed at the problem are indicative of its importance. In addition to the above-mentioned UltraFlow projects, other wet gas JIPs have been conducted at NEL in East Kilbride, Scotland, at the Colorado Engineering Experiment Station, Inc. (CEESI) in Nunn, Colorado, and at Christian Michelson Research in Bergen, Norway. The aim of each JIP has been to further the understanding of measurement devices in quantifying fluid flow rates in wet gas.

F.6.3 Water Volume Fraction Measurement. All of the wet gas flow measurement methods described here have been for two-phase flow, (i.e., they attempt to measure only gas and liquid flow rates). For those cases where the amount of liquid produced is significant, it becomes important that the liquid rate be broken down into flow rates for oil (condensate), water, and any other liquids which may be present, (e.g., methanol).

Unfortunately, in 2002 there are no established methods for robustly measuring water volume fraction in a wet gas stream.

There are research and development efforts known to be underway at several sites, but no successful device has yet been tested by a third party and described in the open literature. Until one of these or another similar technique demonstrates its ability, subsea wet gas measurement will be forced to rely on indirect methods to obtain water volume fraction data.

F.6.4 Hybrid Differential-traditional Meters. Some manufacturers of conventional multiphase meters appear ready to test meters which are variants of their conventional design and which incorporate one or more differential elements in the device. Thus they might conceptually provide a meter which draws relevant information from both the traditional multiphase and differential wet-gas domains.

No results from these meters have been reported in a public forum to date.

F.6.5 Multi-phase Flow Meter Using Partial Separation. Here conventional multiphase flow meters, which might operate poorly in the high GVF region of the two-phase flow map, are used with a partial separation conditioning device upstream. This separates the bulk of the gas for measurement as a separate stream, and lowers the GVF in the main stream to make it suitable for measurement by conventional multiphase flow meters. Clearly the greatest challenge for meter systems of this kind is marinization.



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