State of the Art Multiphase Flow Metering

API PUBLICATION 2566
FIRST EDITION, MAY 2004

American Petroleum Institute

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Measurement Coordination

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API – COPM WHITE PAPER
STATE OF THE ART – MULTIPHASE FLOW METERING

This "White Paper" provides information on multiphase flow metering systems gleaned from more than 150 published documents that are in the public domain. The documentation was prepared from information obtained through mid-2002. No additional research has been funded in the development of this report. It should be noted that the indicated performances data stated in these published documents have not necessarily been verified by an independent body. The listing of these references in the Appendix 2 is intended to provide a comprehensive source of data and information on multiphase metering; the reader needs to carefully review the source of the data in the documents when utilizing the information.

The "White Paper" was commissioned by the American Petroleum Institute (API) – Committee on Petroleum Measurement (COLM) to be used as a framework in the development of "Recommended Practices" on the application of multiphase flow meters in Upstream Production Operations. The format of this white paper follows substantially the outline developed for this project by the Multiphase Metering Standards Task Group.

The term "multiphase metering" in its broadest interpretation is referred to both the wet gas metering as well as the measurement of oil, water, and gas streams. Whether one is conducting a "wet gas" or "multiphase" measurement typically depends on which fluid, (oil or gas) is the primary production as well as the type of equipment used. At the time of gathering this information there were over 1000 installations worldwide that use the multiphase metering technology to achieve improved production measurements and well testing. These multiphase metering systems have utilized four major processes, as shown in Figure 7 of the report, to obtain single–phase flow rates from a multiphase flow stream. The four processes include the conditioning of flow stream, volumetric component measurements, component velocity measurements, and modeling of the multiphase flow. These subjects are discussed in Sections 1-7 of the report. The objective of these sections is to provide the reader with a working knowledge of the principle techniques used in multiphase measurements. This background is used, in Section 8, to propose a classification for multiphase metering systems. Sections 9 and 10 review methods used to specify and assess the performance of the multiphase meters.

The developments in wet gas metering have come from two different directions. A large amount of effort has gone into developing "correction factors" to improve the accuracy of single-phase gas metering devices that are used in conditions where a small amount of liquid is present. On the other hand, elements of the multiphase metering technology have been modified to develop wet gas metering systems. Sections 12-15 discuss types of wet gas, measurement techniques used in wet gas metering, and the performance of wet gas metering systems.

Performance assessment and verification of multiphase and wet gas meters are complicated by the lack of commonly accepted protocol and standards. Current approaches used by operators and industry projects to address these issues are discussed in Section 17. Guidelines to be used for installations, qualification testing, and field testing of multiphase and wet gas metering systems are discussed in Sections 18-21.

The users of multiphase and wet gas meters face three major technical challenges in addition to justifying the cost and risk of the deploying new technology. These challenges are:

- Selecting and qualifying multiphase meters for different applications.
- Assessing the performance of the multiphase meters after installation.
- Getting approval to use multiphase meters from appropriate regulatory bodies.

There is currently no single document that users of multiphase metering systems can consult to address the above issues. Users have relied on vendor information for procurement of multiphase metering systems in a majority of the current installations. There is concurrence within the industry that a “Standard” or “Recommended Practice” (RP) be created to establish a common language to describe the performance of these systems. There is also a need to develop a commonly accepted protocol and procedures to evaluate the performance of multiphase metering systems. Should API decide to pursue the development of a “Standard” or a “Recommended Practice” on multiphase flow meters, the information in this report, as well as a number of currently available specifications listed in Section 22, should provide helpful direction and technical resource for the development of the new document.

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API – COPM WHITE PAPER
STATE OF THE ART – MULTIPHASE FLOW METERING

1- INTRODUCTION

This report documents information available in open literature, and from vendors, on the state of the art of multiphase metering systems. The term “multiphase metering” in its broadest interpretation can be used to refer to both wet gas metering, as well as, the measurement of oil, water, and gas portions of commingled streams, which is commonly referred to as “multiphase metering”. Whether one is conducting a “wet gas” or “multiphase” measurement typically depends on which fluid (oil or gas) is the primary \ production, as well as, the type of equipment used. This report documents both wet gas and multiphase metering systems. There are many more multiphase metering installations than wet gas metering installations. Also, the amount of literature and practical field tests available for multiphase meters is much more extensive than for wet gas metering. This imbalance in available information and literature is reflected in the coverage of the two subjects in this report.

The information in this report is intended to guide the American Petroleum Institute – Committee on Petroleum Measurement, and other API Task Groups, in the development of “Recommended Practices” or “Standards” applied to the multiphase measurements of fluid streams in Upstream Production Operations. The format of this white paper follows substantially the format specified by the Multiphase Metering Standards Task Group in the scope of work for this project.

There are currently over 1000 installations worldwide (IV-30)[*] that utilize the new multiphase measurement technology to conduct production measurements in oil and gas producing fields. The pace of these installations has accelerated significantly over the past 5 years (IV-30). During this period a large amount of data related to the performance of multiphase and wet gas metering devices have been published as listed in Appendix 2.

Multiphase measurement is a maturing technology (II-3). Significant amount of field and performance data are available (II-4, II-6, II-11, II-12, IV-1) to be utilized into some form of guideline to direct the forthcoming demand for the application of this technology. The operators in the North Sea, who were the early users of this technology, have undertaken a number of regulatory initiatives to develop such guidelines (XII-3, XII-8). The need for guidelines is also anticipated by the operations in the Gulf of Mexico (XII-1, XII-2, XII-4, XII-7). This issue is discussed further in Section 22 of this report. The gathering of the information on multiphase flow measurement technology, which is the objective of this “White Paper”, would be a first step in development of API specifications or standards on multiphase meters. To assist the API effort, the nomenclature, terms and

[*] Numbers in parenthesis designate references in Appendix 2. V-30 is reference 30 in Section V.

definitions used by other bodies attempting to develop multiphase metering specifications have been adopted and used throughout this report.

2- NOMENCLATURE AND TERMS USED IN MULTIPHASE FLOW

A number of terms and definitions are employed in describing multiphase flow and measurements. The Norwegian Society For Oil and Gas Measurement (NFOGM) have catalogued these terms in their Handbook Of Multiphase Metering" in reference XII-3. As a contribution to further the use of common terminology, and acknowledgement to the NFOGM efforts, this report has adopted these terms rather than develop new definitions. These terms and nomenclature, described in Appendix 1, are taken from reference XII-3 and will be used in this report to describe multiphase flow and measurement processes.

3- THE NEED FOR MULTIPHASE AND WET GAS METERS

Multiphase meters are devices that measure oil, gas, and water flow rates of a well stream without separating these components into individual phases. The new multiphase metering techniques were developed to replace the conventional two and three-phase gravity based test separators that have been making multiphase measurements in production operations. Well tests are conducted routinely to monitor the flow rates from wells and forecast production. The well test data are also used for reservoir management, production diagnostics and optimization and in some cases even production measurement. To obtain accurate and consistent test results from conventional well testing systems, the equipment requires high maintenance, field personnel intervention, and time to perform tests.

The interest in the new multiphase meters for well testing was stimulated by several factors:

- The cost and size of conventional two and three phase test separators, particularly offshore (II-23).
- The testing time, high maintenance and field personnel required to get accurate and consistent test results from conventional gravity based separators.
- Chemical or mechanical interventions that may become necessary when foaming or tight emulsions create problems separating phases using conventional gravity based test separators (IV-2, IV-14).
- Field personnel intervention needed to get fluid samples for water cut analysis (II-26, IV-13). These interventions further increase the cost and contribute to the inaccuracy and lack of repeatability of well tests (II-17, XI-8).
- Systems that could be installed subsea

The attractiveness of the new multiphase metering systems, operating unattended and without the need for phase separation, stemmed from their potential to avoid or overcome some of the above operational problems. Multiphase meters provide a system that can be installed subsea. In addition, these advantages can produce significant savings especially in offshore operations. The less bulky and lighter weight of multiphase meters was a major attraction for the installation offshore and therefore a significant influence in the evaluation of the technology, especially for operators in the North Sea (II-19, II-22) and the Gulf of Mexico.

The oil industry has recognized the potential benefits of the new multiphase meters (II- 10 to 16). A systematic effort was undertaken in the 90’s by several North Sea operators to identify potential multiphase metering applications, reservoir engineering needs, and meter performances for a number of asset developments in North Sea (II-22). For the past 10 years, considerable effort has gone into developing multiphase meters that can measure gas, oil, and water flow rates at wellhead conditions (II-1). These efforts have led to the development and marketing of several types of multiphase meters. In the past five years, the meter manufacturers and operators have jointly tested multiphase meters under a variety of field conditions to evaluate their performances. In the next sections of this paper, we shall look at the trends in installations of multiphase metering systems.

Wet gas metering is a more recent area of development in multiphase measurements. Wet gas metering covers a variety of measurements in production streams with high to very high gas volume fractions. There is a need for direct measurement of gas under these conditions in such applications as gas condensate and high GOR fields as well as many production operations where gas from separation systems may contain liquid (III-1). Furthermore, significant amount of gas will be produced in the future from remote and subsea fields where production, capital investment, and operating costs must be optimized. As an example, gas production from deep waters in the GOM (III-4) has increased in the last several years. Real time measurement of gas and liquid flow rates are critical in a subsea production system to improve well allocation, optimize reservoir production, and enhance flow assurance. In many of the deepwater reservoirs, the economic developments dictate that several fields be commingled together and processed at a central facility. In such cases, it is critical to be able to measure the produced gas at the wellhead in order to be able to allocate the oil and gas assets to partners in each reservoir (XII-4). These trends have provided much support to the development of more robust and accurate wet gas metering systems.

4- MULTIPHASE METER AND WET GAS METER INSTALLATIONS

The numbers of multiphase meter installed have increased steadily since the first detailed survey was published in 1997 (II-8). Figure 1 shows the trend in the number of multiphase meter installations. This Figure is based on annual surveys of commercial multiphase meter vendors (II-11, II-12, II-14, II-15, IV-30). No such surveys were conducted for wet gas meters. But an informal survey of wet gas vendors indicates that the number of installations using wet gas meters – i.e. gas metering systems that can measure gas and liquid on-line - is about 100.

In the last several years the number of worldwide installations have increased substantially. Currently, there are about 1,000 multiphase meter installations in various areas around the world. While this number is a small fraction of the total number of potential well testing sites, the rate of growth has been substantial and widespread.

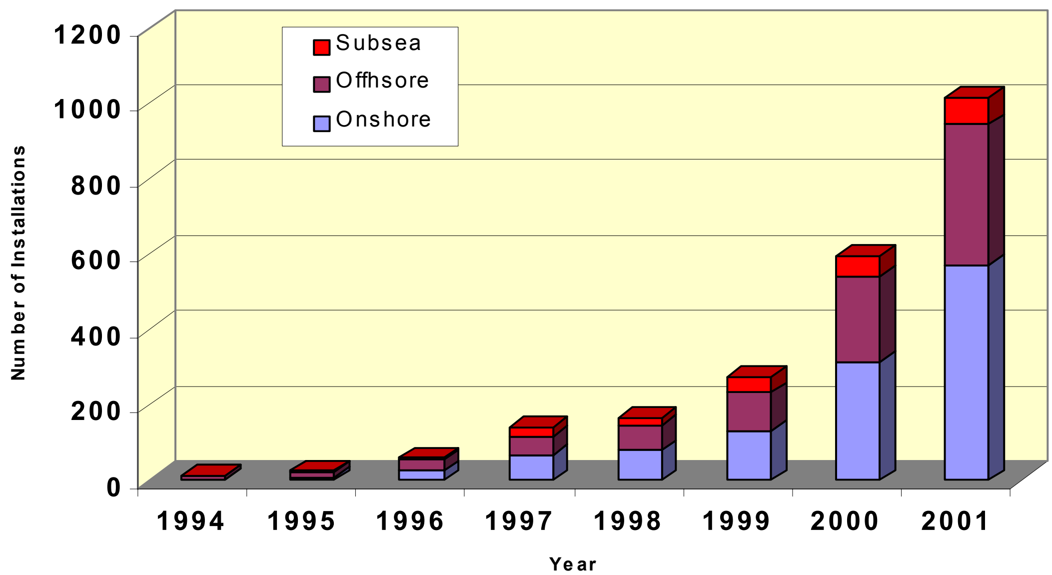

Figure 1 – Multiphase Meters Installed World-wide

The initial interest in the technology was confined to offshore and subsea applications, but over half of the current installations are now in on-shore operations as shown in Figure 1. Onshore operators are using multiphase meters to reduce the cost of well testing. As we will see in the "Application" section of this report, multiphase meters can reduce the cost of well testing by reducing the time needed to conduct a well test. This allows the operator to test more wells with multiphase meters than conventional test separators, which is very important to the management of many marginal onshore reservoirs.

Another trend in the number of installations is the broader application of multiphase metering technology by operators in many production regions. While most of the initial installations were limited to the major operators in the North

Sea, the current distribution of the installations, as shown in Figure 2, indicates broader acceptance of the technology by operators in all production regions.

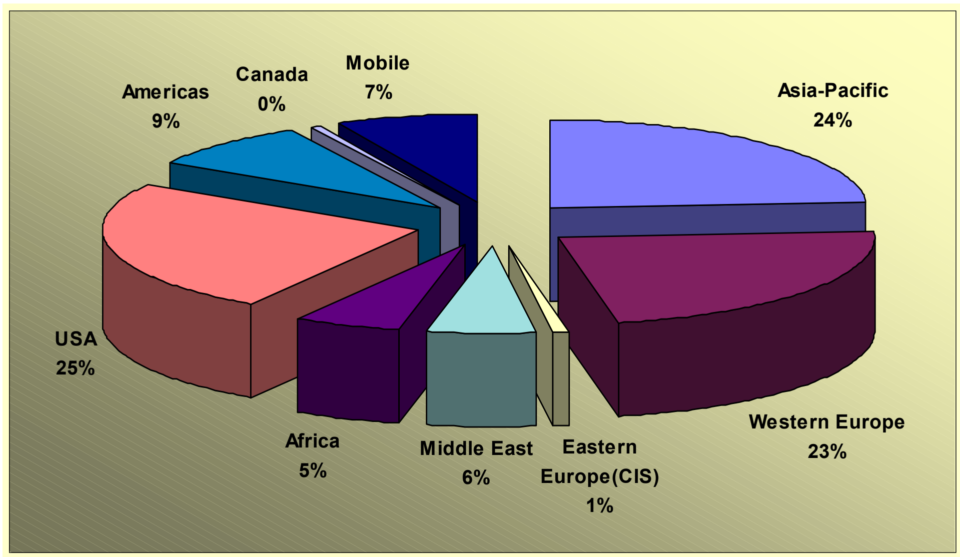

Figure 2 – Regional Distribution of Multiphase Meter Installations.

Two major factors have contributed to the wider spread of the technology:

- Development of efficient compact separators (II-28) has resulted in the availability multiphase metering systems utilizing partial separation (off-line). In contrast to the in-line multiphase meters, which accept the full stream, the off-line systems depend on the removal of most of the gas from the liquid flow stream. The temporary separated gas and liquid streams are subjected to measurements before being recombined into the initial full stream. These off-line multiphase metering systems are less complex and still offer some, if not all, of the advantages of the in-line multiphase measurement systems – i.e. real time measurement, shorter test time, and smaller size and weight relative to traditional gravity separation vessels, but larger than multiphase meters. The development of these systems is discussed in more detail later in this report.

- The compact size of multiphase meters has also resulted in the deployment of mobile systems. Mobile systems have enabled operators to use the multiphase metering technique in remote regions or in operations where a conventional well testing facility would not be available. Trailer-mounted multiphase meters have been used for well testing in fields where wells are scattered over a large area (IV-10, IV-13). In the past 3 years the number of mobile systems have increased significantly.

If one uses the number of installations as a measure of acceptance, then the installation trends shown in Figures 1 and 2 appear to point out that the multiphase metering technology is improving and is gaining acceptance by the industry. It is fair to say that multiphase metering techniques have suffered their share of setbacks and field problems during this period of growth (II-3). The performance of multiphase meters is examined in Sections 10 - 17 of this report.

5- MULTIPHASE FLOW REGIMES

The flow of a mixture of oil, water, and gas in a pipe produces a wide range of patterns that contain various fractions of the fluid components. A number of attempts (I-1, I-2, I-5, I-6, I-7) have been made to define these flow patterns or flow regimes and characterize their impacts (I-3, I-4, I-7, I-8) on the multiphase measurement techniques. The term “flow regime” refers to the geometrical configuration of the gas and the liquid (oil and water) phases in the pipe. Since the three phases of interest can be distributed in a large number of configurations, the characterization of these patterns can be simplified by considering the distribution of gas and liquid phases separately from the distribution of the oil and water (I-7).

When gas and liquid flows simultaneously in a pipe, the two phases can distribute themselves in a variety of flow regimes. The regimes differ from each other in the spatial distribution of the interfaces, resulting in different flow characteristics. The existing flow regime in a given two-phase flow system depends on the following variables:

- Gas and liquid flow rates – superficial velocity of gas and liquid.
- Pipe diameter and inclination angle.
- The physical properties of the two phases i.e. gas and liquid densities, viscosities and the surface tension.

The process of multiphase measurement in any practical application requires that the measurement system be able to perform under a variety of flow regimes. In most field applications, there can be no prior determination of the actual flow regimes. Furthermore, the flow regimes can change quickly with common operational interventions - e.g. closing and opening of a valve. For this reason considerable effort had to be made in the development of multiphase meters to make them able to operate in all flow regimes (I-8). This issue is discussed later when examining the principles of operation of different flow metering techniques. Brief discussion of flow regimes in this section is to orient the reader with common terminology used to describe flow regimes.

In the past, there has been a lack of agreement between two-phase flow investigators on the definition and classification of flow regimes. Shoham (I-6) attempted to define an acceptable set of flow regimes, which is used in this report. The definitions are based on experimental data acquired over the entire range of inclination angles, namely horizontal flow, upward and downward inclined flow, and upward and downward vertical flow. Tables 1 and 2 provide a general definition and description of the flow regimes in horizontal and vertical pipes as affected by the relative superficial velocity of gas and liquid. A detailed description of the flow regimes-velocity relationships is provided in reference I-6.

Table 1 - Flow Regimes in Horizontal /Near Horizontal Pipe (Reference I-6)

Superficial Gas Velocity Ft/s	*Superficial Liquid Velocity Ft/s*	*General Description of Flow Regimes See The Schematics in Figure 3*
0.3 – 30	0.01 – 0.3	Stratified flow – Where gas-liquid interface can be either smooth or wavy as the gas flow rate is increased
3.0 – 30	0.03 – 18	Intermittent Flow – alternate flow of liquid and gas resulting in slug flow
30 –300	0.02 – 20	Annular Flow – The liquid flows along the pipe wall, gas flows in the core with entrained liquid
0.06 – 3	0.3 – 20	Dispersed Bubbles- Gas phase is dispersed in the continuous liquid phase

Table 2 – Flow Regimes in Vertical /Sharply Inclined Pipe (Reference I-6)

Superficial Gas Velocity Ft/s	*Superficial Liquid Velocity Ft/s*	*General Description of Flow Regimes*
>100	0.01 – 10	Annular Flow – The liquid flows along the pipe wall, gas flows in the core with entrained liquid
10 – 100	0.01 – 5	Churn Flow – Similar to slug flow but higher gas flow rates eliminates the boundary between the two phases
1 – 10	0.01 – 10	Slug Flow – Large gas pockets followed by liquid slugs that bridge the pipe cross section
0.1 – 1	0.01 – 10	Bubble Flow – Gas dispersed in continuous liquid phase

Figure 3, taken from reference XI-1, shows schematics of flow regimes associated with the different gas and liquid flow rates in horizontal and near horizontal pipes. Different investigators have used different terms to define flow regimes as noted by the comparison of the flow regimes in Table 1 and Figure 1. Although in a majority of applications the operator does not have control over the changes in flow regimes, it is nevertheless important to recognize the impact of the flow regimes on the performance of the multiphase meters. The superficial gas and liquid velocities in Figure 3 are related to the flow rate of gas and liquid from a well. Thus, plotting of the well flow rates from different wells on a plot similar to Figure 3, can be used to identify the expected flow regime(s) in the well(s), a field, or in operating areas.

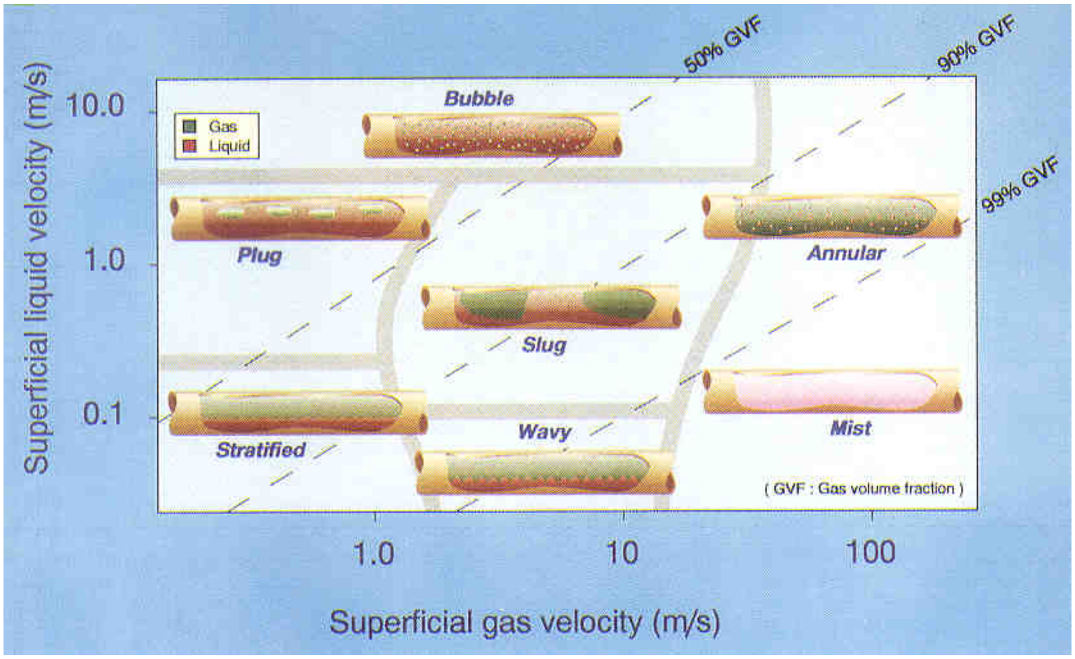

Figure 3 – General Flow Patterns Observed in Horizontal/ Near Horizontal Pipe (Reference XI-1)

Figure 4 shows a plot, similar to the one shown in Figure 3, for a number of wells from South America (SA), Alaska (ALAS), Middle East (ME), and North Sea (NS). Instead of superficial velocity, the gas and liquid flow rates are used for the X-Y axis. Comparison of Figures 3 and 4 shows that most of these wells are expected to be operating in the “Slug Flow “ regime. The impact of flow regimes on the performance of multiphase meters is discussed later. The type of gas-liquid flow rate mapping, shown in Figure 4, can be used to match the performance of multiphase meters with the expected flow regimes in the wells of an operating area.

6- PRINCIPLES OF MULTIPHASE MEASUREMENTS

The primary information required in the measurement of oil or gas multiphase flow streams is the flow rates of oil, water, and gas. The ideal method to obtain this data is to have a multiphase flow meter that would make direct and independent flow rate measurements of these components. Unfortunately, such a device does not exist as yet. Consequently, much of the extensive development in multiphase metering has been directed toward inferential techniques that use the instantaneous velocity and cross sectional fraction of each component to make these measurements. An application of these techniques as applied to multiphase meters used for oil, water and gas measurements is discussed in the next section. Later in this report, how these techniques are applied to wet gas meters is also evaluated.

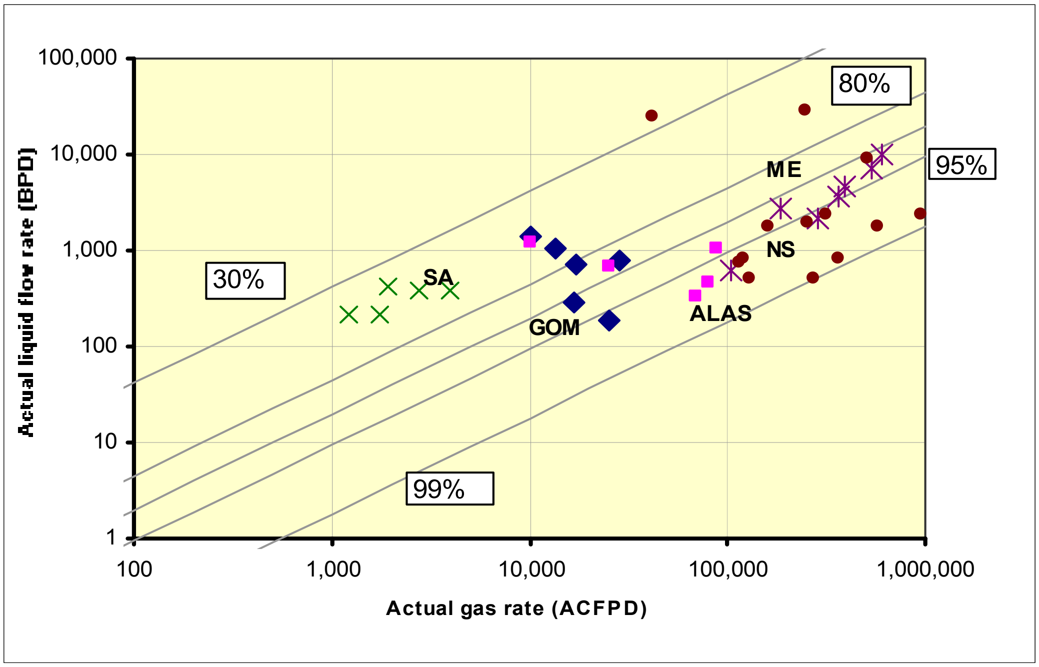

Figure 4 – The liquid and gas flow rates for a number of wells in different operating areas. The diagonal lines delineate the Gas Volume Fraction lines.

7- MULTIPHASE MEASUREMENT TECHNIQUES

For single-phase liquid or gas travelling through a pipe of cross sectional area **A** at an average velocity **V**, the volumetric flow rate Q can be calculated by:

$$\mathbf{Q = AV} \qquad (1)$$

When an oil, water and gas mixture is flowing through the same pipe, the calculations of the volumetric flow rates are complicated by the distribution and the velocity of each phase. A simple approach to estimate the volumetric flow rates for each phase is to establish the distribution of each phase by assuming that each phase is occupying a fraction of the total cross-sectional area at any instant, which is determined by the following relationships:

$$f_O = A_o/A, \quad f_W=A_w/A, \quad f_g = A_g/A \qquad (2)$$
$$f_O+f_W+f_g = 1 \qquad (3)$$

Where f_O, f_W, and f_g are the volume fractions (fraction of cross sectional area **A**) of the oil, water, and gas phases in the mixture. The volumetric flow rate **Q** of each phase and the total (mixture) flow rate are then determined by:

$$Q_o = A\, f_o\, V_o\ ,\quad Q_w = A\, f_w V_w\ ,\quad Q_g = A\, f_g\, V_g \qquad (4)$$
$$Q_t = Q_o+Q_w+Q_g \qquad (5)$$

Where V_o, V_w, and V_g are the phase velocities of the oil, water, and gas phases in the mixture. The task of any multiphase meter is to estimate the volume fractions and the individual phase velocity in the above equations. In order to accomplish this, the developers of the multiphase meters have employed different technologies and modelling of the multiphase flow to simplify the task (II-11, II-13, II-24). Over the last 10-15 years we have seen the emergence of some 18-20 vendors of multiphase metering systems (II-27, II-4) who have used these techniques to develop commercial products. However through mergers and acquisitions the number of vendors has significantly changed. The following three sections discuss techniques used for determination of volumetric fraction as well as component velocity.

7.1- Volumetric Fraction Measurements Using Non-Nuclear Methods

Several Multiphase Metering Systems use electrical properties to estimate fluid fractions. The ratio of oil, water and gas can be inferred from these electrical properties of the fluid mixture bathing the sensor. The relationship between the fluid mixture fractions and these electrical properties is very complex and requires sophisticated models of sensor geometry and fluid flow in order to determine the required fluid fractions. The following provides a very brief discussion of these methods and their relative merits.

Dielectric Permittivity is a property of matter that resists electrical fields and can be measured by determining the Electrical Impedance. The concentration and spatial distribution of the components of the mixture will impact the resistance, capacitance and inductance of the fluid mixture in the sensor. These electrical properties affect the signal loss and transmission speed of electrical signals in the mixture. Measurement of any combination of these properties can allow the fluid component ratios to be estimated. Electrical Impedance is generally defined as the ratio of Voltage to Current for a specific volume i.e. the multiphase meter wetted elements and can be mathematically modelled as a combination of resistance, capacitance and inductance at a specific frequency. From these impedance measurements instruments can utilize lookup tables to determine water cut and other fractions. Alternatively some more sophisticated systems extract information on the dielectric constant of the fluid mixture and use this property in models to predict fluid fractions.

Multiphase Metering Systems tend to use combinations of sensors, frequencies and models to measure an electrical property that enables an estimation of the fluid fractions to be made. Frequency methods from kilohertz up gigahertz have been used in phase fraction measurement devices, as the value of the electrical properties is dependent on frequency. All methods have advantages and disadvantages however there is no published data to show any marked superiority of one method.

Some units measure capacitance of a plate capacitor while others determine the inductance of a coil with fluid running through the coil. In general all units use some kind of model and some kind of empirical calibration to support the accuracy required by the end user.

Meter systems employing separation can have greater flexibility of choice in sensors as the fluid streams are assumed to be less complex. However care has to be taken not to under estimate the complexity of the fluid streams. For liquid streams coming out of these separators, water cut monitors as well as the coriolis density-based methods (II -13) can be used to obtain phase fraction information.

7.2- VOLUMETRIC FRACTION MEASUREMENTS USING GAMMA RAY ATTENUATION

Gamma rays are electromagnetic radiation resulting from nuclear transitions. Gamma rays used in multiphase metering systems are produced by chemical sources that decay with time. When the gamma rays pass through an oil, water, and gas mixture, they interact with the electron and nuclei of molecules within the mixture. This interaction results in the attenuation of the radiation as it passes through the fluids. Thus, if a gamma radiation source is placed on one side of a pipe with and internal diameter **d,** through which an oil, water, and gas mixture is flowing, the intensity of the beam after it has passed through the pipe is reduced relative to that of an empty pipe. If I_O is the intensity of the beam for the empty pipe, the intensity due to the mixture I is governed by the following relationship:

$$\mathbf{I = I_O\, C \exp\left[-d\left(f_O u_O + f_W u_W + f_g u_G\right)\right]} \qquad (6)$$

Where **C** is a constant related to the source and geometry of the set up and $\mathbf{f_O}$, $\mathbf{f_W}$, and $\mathbf{f_g}$, are fractions of oil, water, and gas in the mixture as defined previously. The $\mathbf{u_O}$, $\mathbf{u_W}$, and $\mathbf{u_G}$ are the linear attenuation coefficient for the oil, water, and gas components. The linear attenuation coefficients of oil, water, and gas vary with the energy of the gamma rays. If the above set up is repeated with two different gamma ray energy sources, two independent equations similar to the above attenuation equation can be written. These two equations plus a third relationship, which is that the sum of volume fractions must equal to unity, can then be used to calculate the oil, water and gas fractions in a mixture using the dual gamma ray technique. Figure 5 shows a graphical representation of the dual gamma ray method.

Although gamma ray attenuation provides a relatively low cost non-intrusive method for component fraction measurements, in practice a number of issues must be taken into consideration (II-20). The use of a nuclear source requires safety precautions and compliance with regulations. The gamma ray method can be used over the complete range of component fractions, but accurate component density input is required to calculate accurate component fractions.

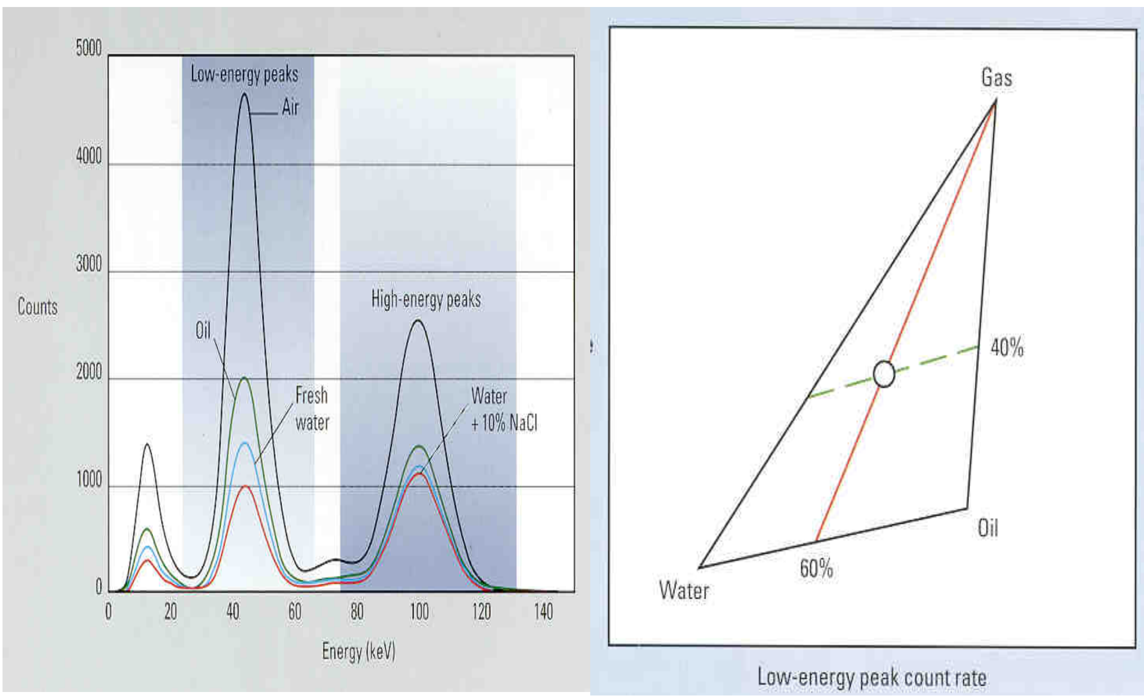

Figure 5- Graphical representation of the dual gamma ray method. The graphs (on the left side) show the attenuation of gamma rays by air, oil and water. Count rates from the high and low energy peaks are used to determine the fraction of each phase. The triangle (on the right side) is a plot of high-energy (vertical axis) and low-energy (horizontal axis) peak count rates associated for an oil-water-air mixture with water cut of 40% and gas volume fraction of 60% (Reference II-31).

The salinity of water can affect the linear coefficient of attenuation for water in the above equation (6) (II-21). Thus a change in water salinity will cause significant error in the measured water fraction if the meter does not compensate for this factor. This density dependent characteristic may require periodic calibrations.

It must be noted however that changes in water salinity also affect other volume fraction determination methods and has to be addressed in any multiphase meter. A Multiple Energy Gamma Ray Absorption (MEGRA) measurement technique has been developed (II-21) to compensate for the salinity changes.

Most dual-energy gamma ray methods use a single radiation source. The “single beam” method has the limitation of being flow-dependent (II-24). Thus, the component fractions derived from the attenuation equation will only represent the actual flow cross section if the oil, water, and gas are “homogeneously” mixed. Reference II-32 describes the development of a dual energy fraction meter that is flow regime independent. Scanning the flow stream and processing the data at very high rates achieve the flow independence feature.

7.3- MEASUREMENT OF COMPONENT VELOCITIES

Venturi devices and the cross-correlation technique are the most commonly used tools for component velocity measurements. When the flow is well mixed – i.e. using a mixing chamber or device – the Venturi meter has been used to measure the bulk velocity of the mixture. For non-homogeneous flow the Venturi meter can also be used if the gas fraction is known (II-42).

The cross-correlation technique is used either with the Venturi meter or by itself to measure the component velocities. The principle of this technique is shown schematically in Figure 6.

Two sensors, separated by a distance **L**, are used to measure the variation in some properties of the flowing mixture. Thus, each sensor can be used to measure the variation in density or dielectric properties. The time delay between the outputs of the two sensors seeing similar variations in the fluid properties can be calculated by a correlation function ($\mathbf{R_{xy(t)}}$) measured over a period of time. The time lag ($\mathbf{T_{max}}$) at which this correlation function is maximized - i.e. both locations show similar variation in the property - is taken as the transit time of flow between the two sensors. The velocity is then determined by dividing the distance separating the two-sensor (**L**) to the time lag ($\mathbf{T_{max}}$). The accuracy of this technique depends on the validity of the assumptions used to derive the velocity of a particular component in the flow stream from the velocity calculated by the correlation function (II-24).

The cross-correlation method measures the velocity of the dispersed phase in the mixture (II-24). In the case of oil/water/gas mixture, the liquid (oil and water) may be travelling at a different velocity than the gas. This difference in the velocity (slip) must therefore be taken into account. Otherwise, the velocity measurement by cross-correlation becomes inaccurate.

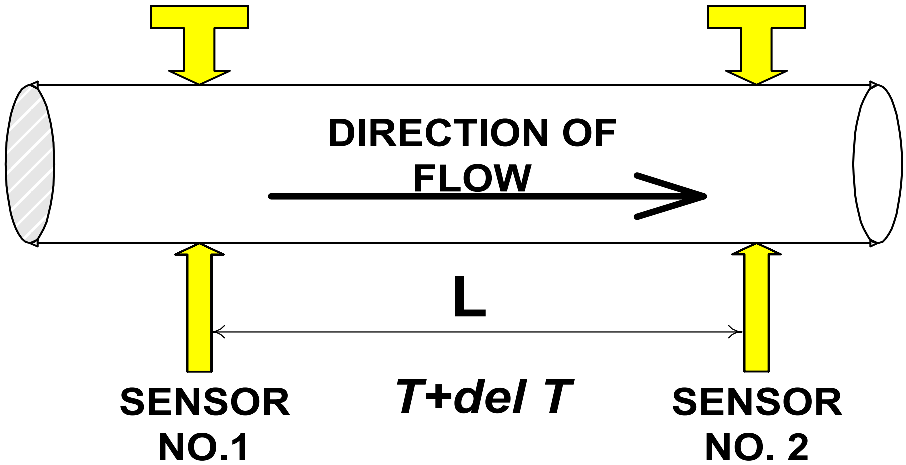

Figure 6 – Schematic of cross-correlation technique used for component velocity measurements.

8- CLASSIFICATION OF MULTIPHASE METERS

Multiphase measurements systems used in production operations utilize a diverse range of equipment from full three-phase conventional separators to in-line multiphase meters that consist of a spool piece with no separation. From the perspective of users, these systems have one common purpose – i.e. to provide accurate flow rates for oil, water and gas. In each system, however, the processes schematically shown in Figure 7 must occur. The processes shown in Figure 7 consist of some type of fluid conditioning, mixture density determination, mixture rate determination, mixture composition determination, and application of a flow model. These functions can be supplied by an instrument or by an assumption in a model (III-4).

The volumetric fraction and component velocity measurement techniques described in sections 8 and 9 are commonly used in these systems. Several references, listed in Appendix 2, have attempted to categorize the multiphase metering systems (II-4, II-11, II-18, II-24, III-4, XII-3). Terms such as on-line and off-line have been used to describe various systems. There is considerable confusion and even an argument that the term multiphase meter should only be applied to systems that can make multiphase measurements without the separation process. The following classification of the multiphase metering systems is proposed as a way to develop a commonly accepted language for multiphase metering. It is proposed that we use the following definitions to designate three types of multiphase metering systems.

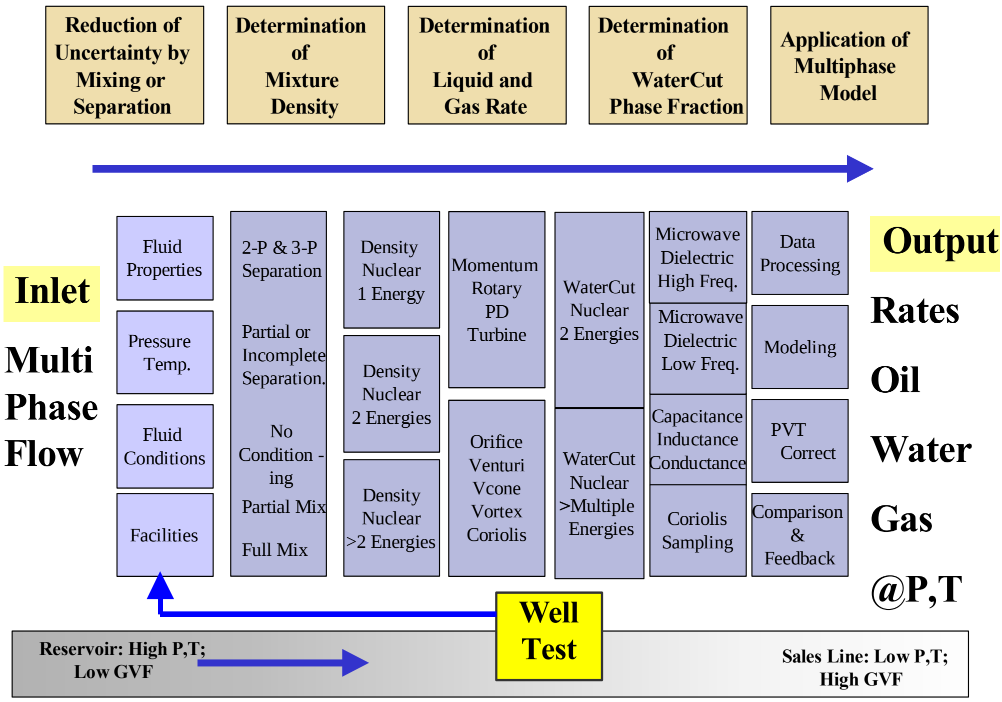

Figure 7 - A multiphase meter can use a number of devices and modelling processes to obtain single-phase flow rates from a multiphase flow stream. The processes are shown schematically in this figure (Reference III-4).

8.1- Type I Multiphase Measurement System

These systems are conventional separators where by definition the gas is saturated at separator conditions and there is no free gas in the liquid. The separated streams are measured and recombined to form the original stream. This category includes 3-phase and 2-phase units both measuring oil, gas and water. These systems may employ some of the continuous oil/water monitoring devices (II-13, XII-5) that were discussed in section 7.

8.2- Type II Multiphase Measurement Systems

In these systems the main flow stream is divided into “gas rich” and “liquid rich” streams. Each stream is subjected to multiphase measurements then recombined to form the original stream.

8.3- Type III Multiphase Measurement Systems

All three phases go through a single conduit and are measured at the same time. This category includes all the so-called inline meters. These meters may use flow conditioning – i.e. use of elbow, mixers, etc (II-9).

In this report we have focused on Types II and III multiphase metering systems. But as a matter of completeness, any attempt toward specification of multiphase metering systems should consider all systems that can perform multiphase measurements. This approach is important because of the following factors:

- Type I systems, which include 3-phase and 2-phase gravity-based test separators, are used in a majority of operations. The number of Type II and III installations is less than 1000 where as the number of Type I installations are in 10,000's.
- Gravity-based test separators are the current "standard" of field measurement within the industry. All Type II and III installations are performance tested against these systems in the field.

The remainder of this report presents technical discussions on the performance of Type II and III multiphase metering systems. But whenever appropriate, Type I metering systems are discussed.

9- ACCURACY- UNCERTAINTY

There is a lot of confusion when it comes to specifying the performance of multiphase meters. This confusion is partly caused by the fact that the issue of accuracy and performance is not well defined, even for single-phase measurement devices (I-3). A second major reason is the lack of consistent and commonly accepted definitions for multiphase measurement accuracy. These issues are further complicated by hardware specifications that are generally written by the manufacturers to accommodate commercial and manufacturing constraints. When a user states that it is desired to measure the flow rate of a well or commingled production stream with an accuracy of ±5%, what is meant is that the desired meter should indicate a flow rate of between 95% and 105% of the "true" flow rate of the well or production stream – if such a value could in fact be actually measured. By definition and for convenience, the ±5% inaccuracy has generally been referred to as the "accuracy". The subject of accuracy and the component of measurement errors that contribute to the performance accuracy are briefly discussed in this section. Accuracy, uncertainty, error, repeatability, and reproducibility are some of the terms that have been used by the multiphase measurement community to define the performance of multiphase meters. For the purpose of this report, only "accuracy", "uncertainty", and "repeatability" terms are used to define the performance of the multiphase meters, as these are the more commonly used terms. For a more comprehensive treatment of "Accuracy" the reader should consult references XI-5 and XI-14 listed in the Appendix 2 of this report.

Figure 8 taken from reference XI-5, illustrates the relationship between accuracy, uncertainty, and repeatability. Consider three temperature-measuring devices that have been immersed in boiling water and have produced the readings provided in the plots shown in Figure 8. The data from all devices have been plotted on a target plot that has circles designating the percentage of error from the true value.

The data from Device “a” are clustered about an average value, but offset from the centre (true value). The difference between the average and the true value is due to the “uncertainty” of the device. In this case the device is said to have a systematic bias or uncertainty of about 1%. The scatter of the measurements about the average in this device is less than 0.5%, except for the one point that is significantly different from the rest. This point is an outlier since it is not part of the normal population. Statistical methods (XI-5) can be used to determine either to reject or include it in the data calculations. Device “a” is considered to be precise (good repeatability), but is not accurate without the correction for the systematic uncertainty, that may be due to the technique or technology used in this device to measure temperature.

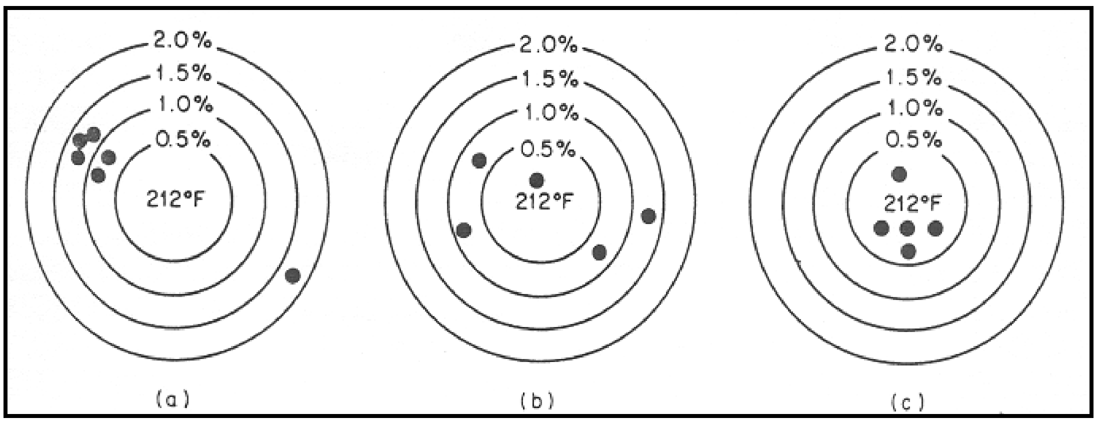

Figure 8 – The contribution of uncertainty, and repeatability to the performance accuracy. Targets showing data scatter, with respect to true value, for three temperature- measuring devices a, b, and c (Reference XI-5).

Data from the Device “b” has a wide scatter about the bull’s-eye. While the average (211.8) is centred around the true value indicating no significant systematic uncertainty, the inability to read consistent values close to each other (random uncertainty) makes this device imprecise or of poor repeatability. The chances of reading a value close to the true value are poor. This device would not be considered accurate especially if one wishes to use this device for trending temperature changes.

Data from Device “c” shows good repeatability as well as low uncertainty. The average of the five readings is very close to the true value of 212 and there is very little scatter around the average. This device has good repeatability and low uncertainty and therefore is an accurate device for measuring as well as monitoring changes in temperature.

Having established the definition of uncertainty and its relationship to accuracy in the previous sections, the process by which the uncertainty is to be measured is reviewed in the following segments. A multiphase flow meter is made up of a number of devices as discussed in section 5 of this report. Each device is performing a measurement function that is schematically illustrated in Figure 7. The uncertainty of the overall system is controlled by the uncertainty of the individual devices (XI-3). Kouba has presented (XI-9) a theoretical approach for assessing the uncertainty of the overall measurement as a function of individual measurement uncertainty. Marrelli provides a practical approach to field evaluation of accuracy in multiphase measurements in reference XI-15.

In practice the uncertainty of a multiphase meters is determined by indexing its performance against a reference metering system – typically a test separator. In this type of comparison, the reference meter must have higher quality of performance (lower uncertainty) to insure a valid performance evaluation as noted in reference XI-3. Since this indexing approach is prevalent in the performance evaluation of multiphase meters, it is important to note the two major elements of the indexing approach. These are:

1. The availability of a satisfactory reference. A reference system must be maintained and calibrated to a high standard with calibration devices traceable to national standards (XI-2).
2. The reference must have higher accuracy than the device being tested. Ideally the reference must have an accuracy that is an order of magnitude (10 times) better than the unit to be tested. However this is very difficult to achieve in actual tests and therefore as a general rule, the accuracy of the reference is normally only 3-4 times higher than the device being tested (XI- 4).

In practice, the discussions between the user and manufacturer, related to accuracy of a multiphase metering system, assumes that the reference system has very good repeatability and therefore in most applications the “Uncertainty” specifications are equated to the “Accuracy” specifications. While the assumption on repeatability may be valid in most cases, users must always be aware that repeatability is a major component of the accuracy.

9.1- Specifications for Accuracy – Uncertainty

Manufacturers and users have utilized different methods of specifying the uncertainty requirements for multiphase meters. Users prefer to specify the accuracy in terms of percentage uncertainty in the flow rates of each phase – i.e. oil, water, and gas flow rates. This method is generally referred to as the “absolute” uncertainty. For a variety of reasons, other methods have been used (XI-1). The uncertainty of the metering system can also be specified as a percentage of the total multiphase flow rate, which is called the “relative” uncertainty method. In certain cases, a mixture of the two approaches can also be used. This will be referred to as the "mixed" method.

In this section we will use an example to demonstrate the application of these methods.

Table 3 below shows the production from a hypothetical well, as viewed from the perspective of a user and a multiphase measurement system. The user is generally looking at the flow rates under standard temperature and pressure conditions. The measurements, on the other hand, are performed at the actual temperature and pressure conditions and then converted to standard conditions. In Table 3 (2nd Column) the user defined flow rates are translated into actual flow rates as seen by the measurement device by applying simplified PVT analysis (oil shrinkage calculations etc.). In practice more rigorous PVT analysis may be necessary and the users and supplier of the multiphase meter should agree ahead of time on the PVT method and assumptions to convert actual conditions to data under standard conditions.

Table 3 - Flow Rates Used in the Analysis of Uncertainty

User Perspective	***Multiphase Measurement System***
Liquid = 500 BBL/D *Oil = 400 BBL/D* *Gas = 400 MSCF/D* *Water Cut (WC) = 20%* *GOR = 1000 SCF/B* *Well Head Pressure = 450 psig* *Well Head Temperature = 150 ºF*	*Total Flow = 3300 BBL/D* *Liquid= 400 BBLO/D + 100 BBLW/D* *Gas = 2800 BBL/D* *Water-Liquid Ratio (WLR)= 20%* *GVF = 85%* *Well Head Pressure = 450 psig* *Well Head Temperature = 150 ºF*

Table 4 shows the results of applying three different methods of uncertainty specification to the hypothetical well in Table 3. The application of the first two methods, i.e. absolute and relative, is fairly straightforward. The absolute uncertainty for the oil and water flow rates in the mixed method was obtained by applying the following relationships:

$$\Delta V_W = SQRT\,\{(\Delta WC * V_L)^2 + (\delta V_L * V_L * WC)^2\} \qquad (7)$$

where:
- ΔV_W = absolute uncertainty in water flow rate
- WC = actual water cut
- ΔWC = absolute uncertainty in WC
- V_L = actual liquid volume flow rate
- δV_L = relative uncertainty in the liquid volume flow rate

Similarly, the absolute uncertainty in oil volume flow rate, ΔV_o, is given by

$$\Delta V_o = \text{SQRT}\ \{(\Delta WC * V_L)^2 + (\delta V_L * V_L * (1\text{-}WC))^2\} \qquad (8)$$

As can be seen in Table 4, different uncertainty specifications result in different accuracy for the oil, water and gas flow rates, even though the specifications may look similar. The "Accuracy" values shown in the last column of Table 4 are the accuracy numbers that are of interest to users. Users are generally unable to accept the large uncertainty levels in multiphase measurements, even though these uncertainty levels may reflect the actual measurements. This may be one of the reasons that a variety of uncertainty specification methods have evolved to make these large uncertainty numbers look reasonable.

Table 4 – Application of Different Methods of Specifying Uncertainty to Well Flow Rates Shown in Table 3

WELL FLUID		ABSOLUTE METHOD		ACCURACY
Fluid	Flow Rate	+/-10% of Phase Volume Flow Rate		+/- Percent
Total - BBL/D	3300	Meter Spec. +/-	Production Uncertainty, +/-	
Oil - BBL/D	400	40	40	10%
Water - BBL/D	100	10	10	10%
Gas - BBL/D	2800	280	40 MSCF/D	10%
		RELATIVE METHOD		
		+/- 5% of Total Flow		
Total - BBL/D	3300	Meter Spec. +/-	Production Uncertainty, +/-	
Oil - BBL/D	400	165	165	41%
Water - BBL/D	100	165	165	165%
Gas - BBL/D	2800	165	24 MSCF/D	6%
		MIXED METHOD		
		+/-10% of Gas and Liquid Flow, +/- 5% WC		
Total - BBL/D	3300	Meter Spec. +/-	Production Uncertainty, +/-	
Oil - BBL/D	400	47	47	12%
Water - BBL/D	100	27	27	27%
Gas - BBL/D	2800	280	40 MSCF/D	10%

The specification of the uncertainty is not limited to the three methods described in this Section. Other variations of the method, designated as "mixed" have been used. However the only specification that provides a meaningful and easily understood accuracy of measurement is the "Absolute" method where the uncertainty of each phase is clearly specified. The "Absolute" method is therefore the preferred method for accuracy specification.

10- PERFORMANCE OF COMMERCIAL MULTIPHASE METERS

Table 5 summarizes the principal measurement techniques used in a number of the commercial multiphase meters that are involved in a majority of current installations discussed in Section 4. There are of course other types of meters (II-44, II-45, II-46, IV-30) not shown in Table 5 that are under development, being pilot tested, or undergoing field introduction – i.e. no more than 2-3 installations. These systems utilize some very novel approaches to multiphase metering. It remains to be seen if these systems will find commercial acceptance.

TABLE 5 – EXMAPLES OF TYPE I, II, AND III MULTIPHASE METERS

Meter Type	***Velocity Method***	***Composition Method***
Type I	Coriolis	Coriolis Dielectric
Type I	Vortex, Cross Correlation	Gas Separation - Densitometer
Type I	Coriolis, Turbine	Gas Separation Dielectric
Type I	Vortex, V-cone Coriolis	Gas Separation Infra Red
Type II	PD, Venturi (Liquid) Venturi/Vortex (Gas)	Gas/Liquid Split Dielectric
Type III	Venturi	Densitometer Dual Energy
Type III	Venturi and Cross Correlation	Densitometer
Type III	Cross Correlation	Densitometer Dual Energy
Type III	DP, Mixer	Densitometer Dual Energy
Type III	PD, Venturi	Dielectric

As noted in Table 5, most of the multiphase meters use a combination of component fraction and component velocity measurement techniques to achieve multiphase measurements. The techniques and strategies used in each meter dictate its strength and the limitations for certain applications. There is currently no widely accepted standard by which these meters can be graded. The general principles of the techniques used in each multiphase meter are known and can be used to assess its measurement capability and uncertainty. But many of the assumptions and modelling, shown schematically in Figure 7, is of proprietary nature and are not always available to users. Therefore attempting to grade multiphase meters on the basis of principle techniques is a difficult task. The approach to classifying multiphase metering systems into three types on the basis of “phase separation”, that was proposed in the previous section, appears to be the more sensible classification method at the time of completion of this report. This classification method is used in Table 5.

Different vendors have used different methods of specifying the uncertainty of their metering system. Section 9 of this report reviewed the issues of uncertainty and accuracy to provide a background for interpretation of various uncertainty specifications used by different vendors. Currently there are no commonly acceptable method for determining the uncertainty level and performance of the multiphase metering systems shown in Table 5.

Each multiphase meter reacts differently to the changes in process conditions such as flow rates (flow regimes), fluid properties (oil density, water salinity, etc.), presence of wax or scale, sand content, and gas volume fraction of the flow stream. A number of field and test loop evaluations have been conducted to identify the effects of flow rates (IX-3, IX-5, IX-6), produced water salinity changes (IV-12) and viscosity changes (VI-12, IX-3) on the accuracy of multiphase meters. The impact of process conditions, fluid properties, and a fourth phase (presence of sand), on the accuracy can vary from “tolerable” to “very significant”. The user should, therefore, grade the advantages of each meter for the specific application on the basis of these parameters.

Appendix 3 contains questionnaires that were developed as a part of the current API project and to assist with any future Standard or RP development. These questionnaires can be used to request data from vendors and assess the impact of the process conditions on the performance of multiphase meters.

11- WET GAS METERING

What is wet gas? Wet gas can be simply defined as gas, which contains some liquid. The amount of liquid can vary from a small amount of water or hydrocarbon to substantial amount of water and hydrocarbon. The amount and nature of the liquid, as well as, the temperature, and pressure of the flow stream can impact the selection and accuracy of the measurement system. For example, the metering system and measurement techniques used to measure gas with small amounts of water vapor (humid gas) would be quite different than the system used at the wellhead of a gas condensate well to measure flow rates of gas and substantial amounts of liquid. It is, therefore, important that “wet gas” be characterized properly before one can discuss the wet gas measurement systems.

A number of attempts have been made from differing perspectives to define and formalize the definition of wet gas (XII-8, III-1, III-4). From a PVT composition perspective, reservoir engineers define wet gas when the producing gas-liquid ratio exceeds 15,000 standard cubic feet per stock tank barrel with stock-tank liquid gravity up to 70 degree API (III-4). From a volumetric perspective, a general definition of wet gas is provided in reference XII-8 as the guideline to be used in developing measurement systems for gas produced in the North Sea. This definition is to be applied to wet gas measurements at the wellhead of a subsea tieback or at the top of a production riser of a host installation. In this guideline, wet gas is taken to mean gas, which is in equilibrium with either water or gas condensate or both in the flowing gas stream. The liquid contents are generally limited to liquid to gas volumetric ratio (LGR) of 0.2 % for flow streams exhibiting stratified flow and 0.5% for flow streams that can be characterized as annular mist flow (see Section 5). From a volume-density perspective, the impact of flow regime, flow stream pressure and temperature, and liquid content of the gas can alternatively be characterized by the Lockhart-Martinelli (LM) parameter (X-1). Using this characterization, wet gas has been defined (VI-1) as a gas stream with a LM parameter of 0.3 or less.

Wet gas metering requirements are affected not only by the composition of the fluids, but also by the intended application. In the following section a classification for wet gas is developed using the Lockhart-Martinelli parameter.

12- TYPES OF WET GAS

Figure 9 shows a proposed map for classifying a wet gas stream, on the basis of superficial velocity for gas and liquid. We have defined three types of wet gas regions in this map. The Lockhart-Martinelli equation is defined as follows.

$$\mathbf{X = (Vsl / Vsg) (\sqrt{\rho l} / \sqrt{\rho g})} \qquad (9)$$

Where **X** is the Lockhart-Martinelli number, **Vsl**, **Vsg, ρl**, and **ρg** denote the superficial velocities and densities of liquid and gas phases, respectively.

The gas volume fraction (GVF) associated with this condition can be obtained from the following equation:

$$GVF = 1/\{(1 + X^* (\sqrt{\rho g}/\sqrt{\rho l}))\} \quad (10)$$

12.1 -Type I wet gas

Wet gas Type I is defined as the region with Lockhart Martinelli number X equal or less than 0.02 as shown in Figure 9.

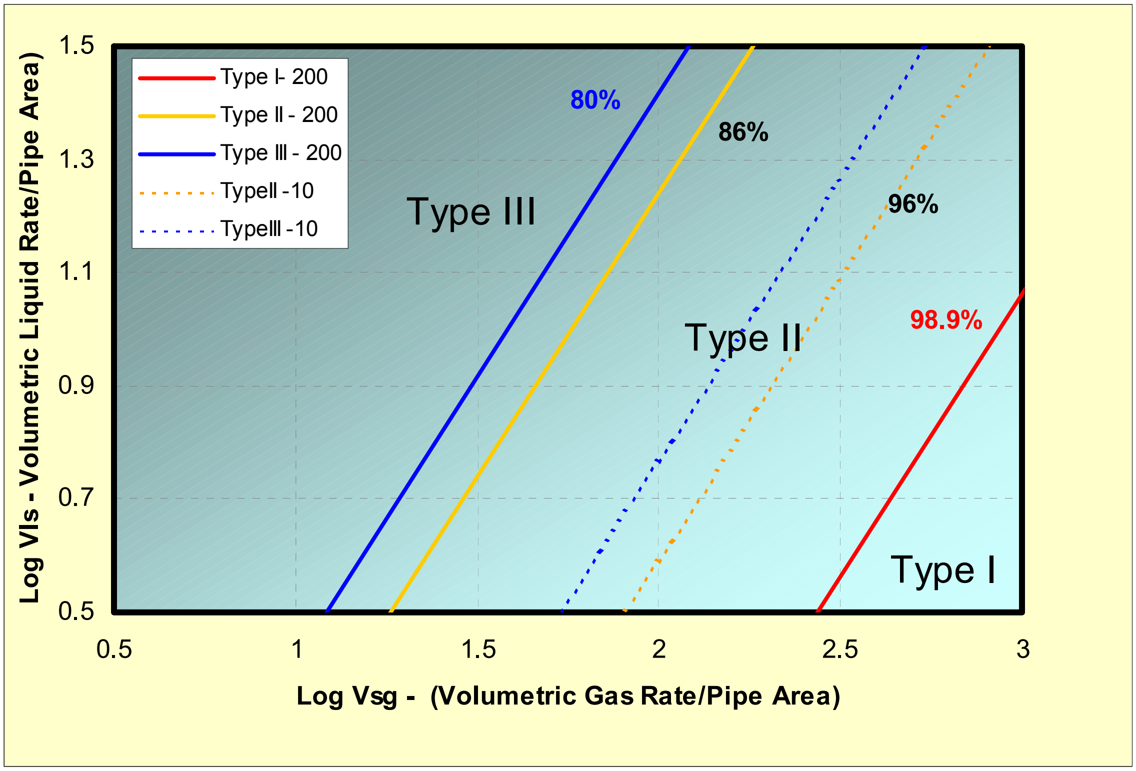

Figure 9 – A proposed map for classifying a wet gas stream. Three types of "wet gas" regions have been defined on the basis of gas/liquid superficial velocity, GVF, and Lockhart Martinelli parameter. The operating pressure can impact the boundaries of the regions as noted by lines associated with 10 bars (150 psi) and 200 bars (3000 psi) operating pressures (reference III-4).

It should be noted that this boundary is dependent on the composition of the liquid fraction and the flow stream pressure, which affects the density of the gas. The dotted and solid lines in Figure 9 illustrate these effects. The two boundaries produced by gas, containing light condensate 37.5 lb/cu.ft.), at pressures of 150 psi (10 bars), and 3000 psi (200 bars). The gas densities associated with these pressures are assumed (III-2) to be 0.6 and 12.5 lb/cu.ft. The resulting GVF lines, which form the boundaries for Type I wet gas, are developed from equation 10 and are shown in Figure 9. If the liquid contains water, then boundaries would shift due to higher density of the liquid.

Type I wet gas corresponds to a range of high GVF's at 99% and above. This type of wet gas would probably consist of processed or un-processed gas with less than 0.5% volume of liquid consisting of water or condensate carryover. Type I wet gas may, however, be produced by a reservoir with very high GOR, high temperature, and or high pressure. The primary interest in this type of wet gas metering is to measure the gas content of the stream. But accurate knowledge of the liquid content would be necessary to develop more accurate gas readings, especially in fiscal metering applications.

12.2 -TYPE II WET GAS

Type II wet gas is defined as the region above Type I in Figure 11 and constrained to the liquid content limited (XII-8, III-4) by the following Lockhart-Martinelli relationship equal to or less than 0.30.

Type II wet gas is typically produced at the wellhead of a well from a gas condensate reservoir. The primary interest of gas metering in this region is to measure the gas. Knowledge of the liquid flow rate is required for accuracy, reservoir management and allocation. In addition, knowledge of the composition of the liquid, i.e. water cut, would be important for improved accuracy.

12.3 – TYPE III WET GAS

All the regions above the boundaries defined by the Lockhart-Matinelli relationship of 0.3 can be designated as a "Multiphase Measurement System" as described in the preceding sections of this report.

It is recognized that in practice there may be considerable overlap in the definitions for the types of wet gas regions described here. The boundaries of the regions also shift as a function of changing pressure. More elegant mapping of the gas liquid mixture that defines the various flow regimes and wet gas characterization are available in the literature (III-2, X-1). A number of wet gas metering strategies and systems have been developed to address these needs. These systems will be discussed in the following sections.

13- WET GAS METERING STRATEGIES

The development of wet gas metering has come from two different directions. A large amount of effort (VI-1) has gone into developing "correction factors" and improved accuracy when single-phase gas metering devices are used in conditions where a small amount of liquid is known to be present. These efforts have resulted in introducing new technology to upgrade the wet gas measurement capability of such devices as differential pressure meters (orifice plates, V-cones and venturi tubes), coriolis force and ultrasonic flow meters. On the other hand, elements of the multiphase metering technology that were intended for multiphase measurements of combined oil, water, and gas streams, have also been modified to develop wet gas metering systems (II-3, VIII-5).

In the last few years, wet gas joint industry projects such as UltraFlow for ultrasonic meters, National Engineering Laboratory (NEL), Colorado Engineering Experiment Station, Inc. (CEESI) and Christian Michelson Research have begun studying the effects of liquid on gas flow measurement accuracy in single-phase meters and wet gas meters. These facilities control their gas and liquid injection rates with high accuracy and cover the full range of required gas and liquid flow rates. The full extent of the research efforts conducted within these programs has not been released.

14- METERING SYSTEMS FOR TYPE I WET GAS

Table 6 lists metering devices for Type I gas metering systems. These are single-phase commercial gas meters and the liquid flow rate is input independently for gas flow rate calculations. These methods assume a constant liquid flow rate estimate over a period until new liquid flow rate is updated. Common methods of determining liquid flow rate are periodic well tests, tracer injection, PVT prediction, and allocation techniques.

If a single-phase meter is used with an estimated liquid flow rate input to a modified gas flow equation, such as the Murdock equation (VI-1) for orifice meter, gas flow measurement uncertainty could improve. The accuracy of the gas flow rate calculation, therefore, depends on the uncertainty of the liquid flow rate input value over that measuring period.

In Table 6, the over-reading values from each flow device are calculated using the gas flow calculation algorithm and assuming the presence of liquid flow is not accounted for. The over-readings listed in Table 6 are extracted from published data (VI-1). Commercial single-phase meters such as orifice plates, venturi tubes, V-cone, turbine, Coriolis force, ultrasonic, and vortex meters show gas flow over-reading up to 6% in Type I wet gas. The over-reading value reflects the increase of density of the total fluid. Reference VI-1 offers more references relative to the performance characteristics of each device.

When utilizing the Type I system, selection of a flow-metering device, liquid measurement methods and their correspondent measurement uncertainty must be considered in order to deliver an optimum system. Since gas flow rate error is relatively lower at $X \leq 0.02$, sometimes more complex Type II or Type III meters may not improve measurement accuracy for Type I wet gas applications.

Table 6 – Performance of Type I Wet Gas Metering Devices With no Liquid Correction (reference VI-1)

Metering Devices	Volumetric Over-reading range (%) for $X \leq 0.02$
Coriolis	0 to 6
Cone Meter	0 to 1.5
Orifice	-1.7 to 2
Turbine	0 to 0.75
Ultrasonic	0 to 10
Venturi	0 to 5
Vortex	0 to 6

15- METERING SYSTEMS FOR TYPE II WET GAS

A range of parameters defined by Type II wet gas metering system is shown in Table 7. Gas and liquid densities, GVF, and LGR at 3,000, 750, and 150 psia (20000, 5000, and 1000 kPa) respectively for 0.3 Lockhart-Martinelli numbers are listed. For this type of wet gas system, liquid entrainment rates are higher than Type I metering system. Type II wet gas meters typically represents a measurement system at production wellheads, commingled pipelines, and well testing applications. Users often require more accurate gas and liquid flow rates.

Table 7 – Gas and Liquid Parameters for Type II Wet Gas Conditions Values are calculated on the basis of LM =< 0.30

Pressure, psia (bar)	Gas Density, lb/ft^3 (Kg/m^3)	Liquid Density lb/ft^3 (Kg/m^3)	GVF %	LGR, BBL/MMSCF (m^3/M std m^3)
3,000 (200)	12.5 (200)	37.5 (600)	85	118 (662)
750 (50)	3.1 (50)	37.5 (600)	92	262 (1,471)
150 (10)	0.6 (10)	37.5 (600)	96	649 (3,644)

Differential pressure devices such as orifice, Venturi, and inverted Venturi respond well to variations of fluid mixture. Murdock developed a two-phase flow correlation for the orifice meter in 1962 and showed the liquid loading of the gas will cause an over-reading of the gas flow rate. Most Type II wet gas meters listed in Table 8 use a differential pressure device plus another technique to measure gas and liquid flow rates. Sampling and tracer techniques can be used to determine liquid flow rate periodically assuming that the liquid flow rates remain constant between sampling intervals. Other devices such as extended Venturi, dual differential and dual Venturi with vortex offer continuous measurement of gas and liquid flow rates.

Three groups of commercial wet gas meters can be identified:

1. The first group of commercial wet gas meters deploys sampling methods. De Leeuw in 1994(X-1) introduced a Venturi meter with tracer dilution to determine gas and liquid flow rates. This technique requires manual injection, sampling, and analysis of the samples. Another meter uses isokinetic sampling method (VI-4) to withdraw 10% of the wet gas and separate the liquid from gas to determine liquid flow rate. It uses an orifice meter to measure the gas flow rate and sampling is automated.

2. The second group of commercial meters utilizes two or more dissimilar devices to determine gas and liquid flow rates. Commercial meters employ this measurement principle of solving two equations (dual meters) with two unknowns (gas and liquid flow rates).

3. The third group of commercial meters uses multiple measurement sensors, which utilize an extended Venturi to measure two pressure drops along the Venturi to determine gas and liquid flow rates.

Table 8 – Commercial Type II Wet Gas Metering Systems
(Data from Reference VI-1)

Metering Devices
Dual Differential
Dual Venturi with Vortex
Extended Venturi
Orifice with Sampling
Venturi/Tracer Sampling

Although the manufacturers of the commercial wet gas meters listed in Table 8 have claimed measurement uncertainty of 2-10% for liquid and gas phase, the actual field-proven accuracy of these devices has not been fully corroborated by the users. There are currently no commonly accepted uncertainty levels for the systems shown in Table 8.

Since all commercial Type II meters use differential pressure devices, it is important to understand how liquid flow measurement uncertainty impacts gas flow rate measurements over the entire range of operational conditions.

Performance and measurement uncertainty of differential pressure devices in wet gas conditions is well studied up to Lockhart-Martinelli number equal to 0.30 (VI-1). However, performance data for liquid measurement using these devices are not available in public domain to verify the accuracy of liquid flow rate measurement.

Other approaches (VI-1) to wet gas metering, i.e. ultrasonic meters, have been studied for wet gas applications but not yet introduced as a commercial product.

16- METERING SYSTEMS FOR TYPE III WET GAS

Metering systems used for this type of wet gas are multiphase metering systems that were developed to measure flow streams composed of oil, water, and gas mixtures. These systems were discussed in sections 10 of this report. To be eligible for this classification the multiphase meters must make an oil, gas and water rate determination at relatively high GVF > 80% or X≥0.3

17- PERFORMANCE- MULTIPHASE AND WET GAS METERING SYSTEMS

Multiphase meter performance assessment is complicated. Accuracy claims by the manufacturers for the commercially available meters described in Tables 5 and 8 are difficult to verify. Since there are no generally accepted standards for performance, users may require performance testing. At the time of completion of this report three different approaches had been used to check on the performance claims for metering systems shown in Tables 5 and 8. These approaches consist of:

1. Third party testing where vendors and end users are not involved. These tests are generally conducted in a test loop under controlled conditions. Reference uncertainty is usually very low.
2. End-user field-testing where the multiphase meter is tested against conventional test separators. Reference uncertainty is usually dependent on field separators and may be unknown.
3. Manufacturer sponsored testing either in a third party test loop or at the manufacturer’s facility. Reference uncertainty varies, and may not be known.

The above test programs can be further categorized by use of fluids ranging from air and water to full hydrocarbon. Programs using simple fluids show high accuracy but application of results to the field may be limited. Full flow field-testing suffers greatly from lack of verifiable references and narrow range of flow conditions. We will discuss the guidelines to be followed for these types of tests in Sections 18-20.

A number of joint industry studies have been conducted to establish that these meters can perform to the specifications and capabilities claimed by the manufacturers. The National Engineering Laboratory (NEL) in UK has conducted a number of joint industry projects (IX-1) to characterize the performance of multiphase flow meters. The results are not published but released to the multiphase meter manufacturers who have shared the data with their clients. Attempts were made, as a part of this API white paper project, to contact NEL and establish the condition under which some of the results could be used in this report. NEL did not agree to allow the data to be used in this white paper.

In addition to the NEL tests, meter manufacturers and operators have jointly tested multiphase meters in a variety of applications. Several operators have conducted field trials to compare the multiphase meter measurements with conventional test separators. These results have been published (II-19, IV-3, IV-9 IV-10, IV-11, IV-13, IV-14, IV-16, IV-19, IV-22, IV-24, IV-25, IX-4 to IX-7). Many of these tests compare and index the performance of the multiphase meters to gravity based 3-phase test separators. Many of these tests also claim performance accuracy of 5-10% for oil, water, and gas flow rate. Furthermore the use of Type II and III, as well as Type I multiphase meters, that can provide continuous measurements of the flow stream has provided additional important information on the dynamic nature of flow stream from wells (IV-7, IV-17). These advantages present adequate justifications for the operators to begin looking at this technology to improve their well testing. A number of operators have already installed such multiphase meters and their justification and resulting operational benefits derived from the use of the multiphase metering technology can be used as a guide (IV-13, IV-14, IV-15, IV-16).

A number of field tests (IV-19, IV-21, IV-24) have also been conducted to assess the performance of multiphase meters, in the wet gas region. In field tests, where the performance of multiphase meters have been compared to conventional test separators, uncertainties of 5-10% have been claimed. Some field tests have even claimed uncertainty of 2% for wet gas measurements. But it should be noted that these accuracy performances are obtained by comparing the gas flow measurements against conventional separators that generally use gas metering devices described for Type I wet gas metering conditions. In most of the field tests, these “reference” devices may be operating in Type II or even Type III wet gas conditions. Their uncertainty, without the use of correction factors, would be high. Comparison of the data from field tests with these references of questionable accuracy can be misleading. A number of guidelines are provided in Sections 19 and 20 of this report to address the above issues.

18- INSTALLATIONS GUIDELINES

Installation of multiphase measurement systems (multiphase and wet gas meters) should consider steps that would not only maximize the performance but also ease the verification and periodic testing (calibration) that may be necessary. These systems may require specific piping and fitting arrangements (XII-3), mechanical supports, and electrical equipment installation. Vendors generally provide this type of information to the users. The Multiphase Metering and Wet Gas Metering Performance Questionnaires provided in Appendix 3 of this report can be used as a guideline to request documentation from vendors on piping, installation description, electrical and instrument hook-ups, and accurate cabling requirements.

For the rest of this section the discussion is focused on the Type II wet gas and Type II or III multiphase measurement systems. In a majority of field installations Type I multiphase meters – i.e. 2-phase and 3- phase gravity based test separators, are used to verify the performance of other multiphase measurement systems. While Type I multiphase meter installations are outside the scope of this project, when appropriate, issues related to their installations and performance are addressed. The following issues should be addressed in field installations for multiphase metering systems:

1. For consistent performance, the measurement system must be sized to cover the maximum and minimum instantaneous fluid rates expected from the wells in question both initially and in the future. Section 7.5 of reference XII-3 provides a proposed data sheet that helps to define the measurement system's required operating ranges.
2. Complete system documentation including a detailed Piping and Instrumentation Diagram (P&ID) showing all instruments, set points and process conditions is helpful in passing operating practices and procedures to new operating personnel. The P&ID is helpful in identifying the location of critical system elements such as pipefitting, pressure and density measurement devices, control valves, and the operating set point.
3. It is generally preferred (XII-3) that volumetric measurement results are expressed at standard conditions (e.g. 14.696 psia and 60 ^{o}F). It is suggested that the measured values of oil, water, and gas also be retained at their actual measurement conditions partly because of the difficulty of accurately referring the measured values to new operating conditions. The problem is not just referring volumes to new operating conditions but also accounting for mass changes that can occur. Even if the measurement were perfect at the initial point of measurement as soon as a computation is performed to reflect the measurement at new conditions errors are introduced. Taking readings at one set of process conditions and referring them to another set of process conditions requires the use of PVT (Pressure-Volume-Temperature) analysis. As a final observation, the referring of measurement results from one set of process conditions to another must be done carefully after the PVT model has been proven and accuracies of 5% or better are expected.
4. Gas breakout when flowing through single-phase liquid meters, used in Type I multiphase meters, causes inaccuracy. If the Type I system utilizes gravity separation equipment, the liquid discharge piping from this equipment to the liquid meters should be designed (I-10) to eliminate gas breakout in liquid meters. Reference I-10 discusses methods for preventing whirlpool in the

outlet and establishing maximum discharge velocity for self-venting of gas from flowing liquids.

5. Another cause for gas breakout in liquid meters is the pressure drop that occurs between the vessel and the meter. This gas breakout occurs if the liquid line pressure is below the last separation pressure, which is the liquid's vapor or bubble point pressure (XI-6). The assumption that the last separation pressure is the fluid's vapor pressure or "Bubble point" suggests careful piping design and meter selection must be followed to provide enough head pressure to overcome the pipe frictional loss and meter pressure drops. Too much loss drops the fluid pressure below the "vapor pressure" and causes gas break out in the meter. If setting the meter several feet below the separator liquid level is not possible or there are too many pipefittings upstream of the meter to prevent gas break out in the meter then the liquid must be pumped through the meters (XI-6). Obviously, two-phase flow through a single-phase meter leads to uncertainty, which is dependant on the type of meter. (XI-13)
6. If automatic samplers are used as a part of the multiphase metering system, references XI-11and XII-9 can be used to establish the requirements of velocity and flow conditioning that must be included in the sampler design and installation.
7. Flow rates may be expressed in mass rate units instead of the more common volumetric rate units. The conversion methodology must be agreed to. Refer to reference XII-8.
8. Instrument wiring should be installed to minimize electrical noise including proper use of shielding, grounds, and electrical and radiation isolation.
9. There are some special requirements if the multiphase meter utilizes a radiation-based source. These requirements include tracking of the radiation source and general worker safety. Tracking the radiation source can be done by the operator or through an approved third party contractor. These sources must be tracked on and off the property, as well as, to and from the property by a trained entity. While on the property, swab tests are performed for radiation leakage with the swab sent off for evaluation.
10. Safety requirements and regulations related to item 9, may dictate the need for an individual on location, who is trained in radiation awareness and safety. Workers in the area may have to have radiation awareness training. Some regulations may require that the area around the densitometer be fenced with the gate locked.
11. If a gamma densitometer is used in the multiphase metering system, field calibration may be necessary using the well water and gas at temperature and pressure. It is imperative that when calibrating the gas phase the meter be absolutely dry internally. The installation must consider ways of providing this capability.
12. Wet gas meter accuracies are affected by the degree of insulation of the meter run and pressure taps from the meter body to the process instruments (XII-8). Pressure taps are especially affected by cooling which causes liquids to condense in the tapping line.

19- TESTING GUIDELINES

Testing of multiphase and wet gas meters are generally conducted before these metering systems are installed in a field. The purpose of these tests may be to confirm the principle of operations, qualify the measurement concepts for certain operations, or confirm and accept the accuracy performance of the systems. References 2-4 in section IX and 1-4 in section X of the Appendix 2 provide examples of these types of tests. These tests may be conducted at test loops (IX-2, IX-3, IX-4, X-4) or under controlled conditions in a field (IV-22, IV-23, IV-24). In this section we will cover the guidelines for the following types of testing:

- Factory Acceptance Tests (FAT)
- Test Loop Qualification
- Field Test Qualification

The guidelines and issues to be addressed in the FAT and Loop Test are similar. Factory Acceptance Testing generally can not cover all operating ranges of the measurement system due to limited facility fluid rate capability, limited facility fluid compositions, or limited facility process conditions in the form of pressure or temperature. Test loop qualification may therefore be necessary to augment the FAT tests. In either case, it is highly advisable that the test matrix be spelled out in the original purchase order and agreed to by all involved parties. Reference XI-1provides guidelines and the corresponding evaluation forms for a "Format For Initial Evaluation of Multiphase Meter Implementation". Sections 19.1 to 19.2 describe items that should be used as a guide for conducting FAT and Loop Tests.

19.1- ITEMS TO HAVE AVAILABLE FOR REVIEW BEFORE AND DURING TESTS

1. **Documents showing the accuracy and process capability of the test loop**: Because the test loop is establishing the credibility of the "MUT" (meter under test) the integrity of the test loop must be demonstrated. Flow loop personnel should be able to produce proof of recent certification of all loop instruments including temperature, pressure, and density instruments, if used, to metrology standards. An analysis of the fluids used even if they are water, refined oil, and air should be provided. This is especially true if the water is doctored with salts.
2. **Vendor documents showing the theory of operation**: Descriptions can be given in the vendor's manual or by reference to open literature. See Appendix 4 – Performance Questionnaires.
3. **Installation requirements:** Include detailed piping and instrument layout and hook up drawings etc.. This should include a Piping and Instrumentation Diagram (P&ID) and detailed wiring interconnection drawings including communication cables.
4. **Maintenance requirements:** Include calibration procedures for future field recalibration.

5. **Basic calibration sheets:** Sheets should be available for all of the instruments with any special calibration requirements – i.e. fluids identified and their availability sourced and certification sheets and Material Safety Data Sheet (MSDS) sheets supplied.
6. **Listing of special test equipment:** Identification of any special test equipment or test techniques required for calibrating all or parts of the multiphase measurement system.
7. **Failure mode test requirements:** Many times the action taken by a flow computer when one or more end devices fails or radically changes is not clearly identified or understood. It is suggested here that the various process instruments go through a simulated failure to demonstrate how the flow computer records the failures with the actions recorded and reported. In fact this series of tests will also test the recording of error messages and system's alarms that might occur. .
8. **FAT flow rate evaluation matrix:** For production operation one of the most important measurements made during a well test is the produced oil rate or volume. Therefore, it is vitally important to evaluate the measurement systems water cut measurement performance. These tests should include, if possible, zero gas and maximum gas rates. As part of the water cut tests at various gas rates the total liquid rate should be varied over the designed range. As a minimum the FAT evaluation matrix should include four liquid rates, four water cuts, and four gas rates which makes for an evaluation of 12 different flow regimes. The need for these points is as follows: 1) 0 to 100% water cuts at various liquid rates (liquid mixing) with no gas (if possible) proves basic operation of the water cut instrument in the oil-continuous and water-continuous phases, and 2) the addition of gas demonstrates the ability of the system (Flow Model) to extract the water cut from a three-phase system at various gas volume fractions. In the oil continuous water cut tests, one value is 0%, and the second is 40% (just before phase inversion). In the water-continuous water cut test, the third value is 60% (after fluid inversion), and the fourth is 100%. It should be pointed out that one cannot extrapolate performance between test points, mainly because the flow models are not linear solutions. These tests are not the final system calibration. For all multiphase measurement systems including Types II and III, the final calibration of the system is part of the field commissioning activity.
9. **Listing of proposed meter and system factors:** All settings for the meter, computation systems, test systems and associated equipment should be pre-defined.

19.2- PERFORMANCE OF FACTORY ACCEPTANCE TEST (FAT)

1. If at all possible these documents should be in electronic form including Computer Aided Design (CAD) drawings of the mechanical aspects of the equipment.

2. Agreement between the way the manual says to hook up the equipment and what was actually done. It is suggested that the final set-up be done in the presence of the customer.
3. If the Multiphase Measurement System utilizes one or more HMI's (Human-Machine-Interface) that have screen presentations including graphics with dynamic data appearing on the displays, they must be validated for proper data placement, calculation, and update frequency,
4. If the multiphase measurement system is a wet gas system, water cut may not be a required solution. Conventional water-cut instruments such as microwave, or capacitance, or radiation densitometer do not function properly at these elevated gas volume fractions.
5. If the measurement system is wet gas or GVF >98% at the meter conditions, the FAT will probably have to be at a third party facility. This is especially true for Venturi and Sonic meters. Measuring the liquid in high gas fraction can use the tracer technique but one can also use a separator or a second verified meter (XII-8).
6. If the desired FAT matrix exceeds the vendors system capabilities, the FAT would have to be performed at and by a third party test loop (see reference XI-1). If the FAT is performed at a third party test facility, the purchaser may wish to have either personally witness or have a third party witness the tests. It must be clear if the vendor can make any changes after hook-up and commissioning and during any repeat tests. The flow loop operator must be involved in any pre-test meeting so he understands the ground rules. The flow loop operator may have to determine the time of stabilization between each matrix point.
7. All valves, solenoids and other end devices that are part of the metering system need to be activated and performance tested to determine if they operate properly.
8. Agreement must be reached between vendor and purchaser on how to handle the changing of any meter or system factors during the FAT and later during final field commissioning. It is recommended that no factors be changed during the final FAT matrix.

19.3- ITEMS TO BE MADE AVAILABLE TO USERS AT THE END OF FAT

1. The vendor should supply a formal listing of ALL parameters and constants along with their values at the conclusion of the FAT. The accepted ranges and identification of those that can be changed by field personnel should also be supplied.
2. Sign-off sheet to sign, acknowledging that the system met the agreed upon matrix of tests.
3. Report of system measurement results with illustrations in the form of error graphs and exception explanations. Reference XI-1; Section 9.3 suggests a "Format for Presentation of Summary Test Results".
4. Signed calibration sheets for all instruments.

5. Data sheets for all instruments with process variables and equipment model numbers, stating especially any changes in scaling or ranges done during the FAT.

20- FIELD TESTING GUIDELINES

Field tests may be conducted to qualify the meter performance under operating conditions, either as a precondition to the purchase or subsequent to the field installation, to verify the meter performance. The two types of field tests have to address a common problem – i.e. knowing the exact amount of multiphase fluid that flows through the meter. There are three options for establishing the correct amount of fluid:

- Capturing fluids that flow through the system during the test and measuring them with secondary equipment except for the gas. This option requires extra equipment that must be calibrated and certified.
- Proving all system components including the model, and then calculating an implied accuracy by inference. This option requires calibration of end devices under similar conditions of fluid properties, pressure, and temperature as well as flow modelling. These requirements make this option impractical.
- Indexing the performance of the new system against an established multiphase measurement system such as a Type I gravity based test separator.

Not surprising, the third option is the most common method employed in the field tests. The following list should be used as a guide to prepare for the field tests:

1. Establish performance expectations that are within the design and tested constraints of the system. These expectations are the result of FAT testing and any third party calibration that was performed.
2. The field test will use fluids from wells. System accuracy degradation typically occurs for wells that have operating liquid rates, gas rates, water cut, or gas volume fractions outside the system's designed accuracy range. This degradation may also be caused by factors other than fluid rate, such as excessive viscosity variation, fluid tendency to foam, or reverse emulsions.
3. Install inlet and outlet isolation valves, low point drain valves, and high point de-pressurization valves so the operator can isolate, depressurize, and drain equipment to inspect for compromised internals or calibrate meter modules. System isolation, block and bypass valves should be the block and bleed type with the bleed monitored during isolation. Sample ports should be available just downstream of flow and water cut measurement devices. These sample ports must be properly designed and installed per the manufacturer's recommendation and reference XII-9.

4. Automatic sampling is generally not advisable for systems that store and dump due to the lack of uniformity of the water cut profile during the vessel discharge cycle especially for Type I multiphase measurement systems that use gravity-based separation.
5. Any fluid meter used as a reference meter should have isolation and drain valves to allow the installation of either a master meter, or an external system such as a prover loop.
6. If a separation vessel is used all liquid level controls should have their floats and/or displacers installed in quiet areas, stilling wells, or external bridles with isolation valves visible level indicators.
7. If special calibration fluids are required for calibrating parts of the measurement system, those parts should be capable of isolation with flanges, spectacle blinds, and jackscrews or other positive means. In addition, pressure-rated fill and drain connections need to be provided.
8. If system proving involves flowing to a calibrated tank, valve-isolated connections should be provided, the tank should be equipped with low volume gas measurement in order to capture the combination of Flash gas and gas carry under from the pressure equipment. All instruments should be installed with process isolation valves. There may be some problems with temperature measurement, as some meter vendors do not wish to place instruments in a thermal well.
9. The gas meter and its associated end devices must be calibrated. If a Venturi device is used, the internal dimensions should be constructed and checked per appropriate International Standard Organization (ISO) requirements prior to proving.
10. The correct “Z” factor or super-compressibility must be calculated or entered into the gas computation. This may require a gas composition analysis with mole fractions entered.
11. If the gas measurement system’s range ability involves automatic switching of meters or meter runs the switching valve(s) need(s) to be tight shut-off. Soft seats with a bleed measurement port may be required.
12. Liquid meters must be proven at the viscosity and flow rates expected during system proving with the appropriate meter factors entered into the liquid flow computation.
13. Gas and liquid meters should have the ability to provide pacing pulses for use in sampling or other rate-dependant operations. Flow computers for liquids should have the ability to accept the basic meter K-factor (KF) and a proving meter factor (MF).
14. The main flow computer system should have data backup and retention capabilities ranging from days to a month depending on local requirements. This flow computer should be able to communicate with a RTU or DCS system. Pressure and temperature instrumentation should be certified as a part of calibration. Their analog output should also be calibrated as well as the analog input to the flow computer or other electronic device.

15. The overall measurement system should be placed on line with no well selected for a period of time - possibly 24 hours. During this time system parameters including meter outputs should be monitored for any spurious activity. The system should not record any rate related updates.

21- PERIODIC FIELD TESTING

Periodic field-testing may be required as a scheduled maintenance wherein the end devices or metering systems have to be verified. This verification may range from simple calibration of end devices to certifying equipment to some standard. To verify the metering systems, it may be enough to test a given well and if the results are the same as previous tests, the system is declared satisfactory. What test options are available are driven by the well rates. This is especially true for wet gas measurement systems, which generally exhibit very high gas rates and very low liquid rates. If the well production rate is higher than a couple of hundred barrels per day, the only options for verification may be testing/indexing the new metering system against a Type I multiphase metering system with gravity separation.
The following list should be used as a guideline for conducting periodic field tests:

1. Calibrate all individual instruments that form any part of the well test function including process instruments, level controllers, etc. Retain calibration records of these instruments.
2. If the system utilizes single-phase meters, perform meter proves with a master meter in series or by removing the meter and calibrating it remotely. Incorporating a prover loop or connecting to a prover tank also suffices. If during this proving process, valves isolate parts of the system, those valves must be checked for signs of leakage.
3. Validate all system constants and factors to insure that the flow computer calculations are as expected. Over time, factors are sometimes changed to cover a one-time event but for some reason are not changed back to their proper value.
4. If a sampler is used, it should be cleaned and the sample size calibrated. It is assumed that the sampler is installed properly and that the sample extracted is representative of the fluid conditions. If the sample head is a kinetic type, its internal parts need to be maintained. Poor sample representation is very often the result of poor homogeneous mixing due to low fluid velocity, slow pacing, or improper installation location (II-26, XII-9).
5. The pressure of the well, selected as the “proof well”, should be recorded before turning it into the test system. The test rate for this well may depend on the closeness of the test pressure to the production pressure. This has little to do with proving but the registered results when compared to the well’s historical performance, affects the acceptance of the proving.

Also all counters and accumulators should be checked and cleared to zero at the time the test officially starts.

6. The duration of the test period is a function of the well and the method used in verifying. If historical performance is the reference, the well duration should be in excess of 12 to 24 hours. If the proving is only comparing volumes and rates between the system and reference and not considering what the well “should” produce, the test time can be much shorter:- i.e. three to four hours or however long it takes to fill a calibrated tank or accumulate enough data (see reference IV-16).
7. Gas is typically the hardest fluid to verify because it cannot be stored in a calibrated volume. Because of this it tends to be the most uncertain of measurements, especially in Type II and Type III meters. If it is separated as a single phase, then verification is straightforward by inference. If it is not separated, verification may have to be done by a test separator.
8. It is suggested that multiple verification runs be made utilizing different wells. If the accuracy of data collected is consistent, that should be sufficient. However, if the error spread is greater than 10% high to low, additional runs need to be made, in order to produce a better average. This is inferred from reference XI-8. In order to have a 95% confidence that the measurement is accurate, the measurement average error cannot be any less than 10%. The reason for repeated runs is the dynamic nature of the measurement, which changes measurement conditions ever so slightly even if the same well is tested. Some wells have a wider range of dynamic performance than other wells. Another reason for variation of results is system calibration, which is why the verification tests are made. Because there are three fluid phases, verification results must include all three phases (see reference II-17).
9. Once the proving is completed, the appropriate meter factors are calculated and entered into the measurement system. For conclusiveness, one final series of tests should be run to verify the meter factors.

22- REGULATIONS AND STANDARDS

Due to the increasing interest in the application of multiphase and wet gas metering systems in production operations, a number of organizations are attempting to develop specification and regulatory documents to address these systems and their applications. The publications listed in the Section XII of the Appendix 2 describe some of these initiatives. There is currently no single document that users of multiphase metering systems can utilize to procure the hardware for an application. Users have relied on the vendor’s specifications for the procurement of multiphase metering systems in a majority of the installations shown in Figure 1.

API formed a team named the Upstream Allocation Task Group (UTAG) which reports through the Deepwater Operations Steering Committee (DWOSC) who then report up to the Executive Committee on Drilling and Production Operations

(ECDPO). The UATG role is to develop recommended practices to meet business and regulatory needs using MPFM. The Core group is made up of operators with interests affected by this work along with members of the Minerals Management Service (MMS). This group using the work from this paper and all the following mentioned references will develop a Recommended Practice for use of multiphase meters which will then be turned over to API COPM for consideration to develop a measurement standard.

1. "Allocation Measurement", Manual of Petroleum Measurement Standards, Chapter 20, Section 1, September 1993.
2. "Use of Subsea Wet-Gas Flow meters in Allocation Measurement Systems", API Recommended Practice RP 85, August 28, 2002.
3. "Allocation of Gas and Condensate in the Upstream Area", Draft version of Technical Report – ISO TC193 SC3 WG1, May 18, 2002.
4. "Handbook of Multiphase Metering", The Norwegian Society for Oil and Gas Measurement, published by NFOGM, September 1995.
5. "Subpart L – Oil and Gas Production Measurement, Surface Commingling, and Security", 30 CFR Ch. II, (7-1-98 Edition), Minerals Management Services.
6. "Guideline Notes For Petroleum Measurements Under The Petroleum (Production) Regulations", Department of Trade and Industry, Oil and Gas Division, UK, Issue 6 – October 2001.

APPENDIX 1 - NOMENCLATURE, TERMS, AND DEFINITIONS

The following terms and definitions are adopted from the "Handbook of Multiphase Metering", developed by the Norwegian Society for Oil and Gas Measurement, published by NFOGM, September 1995 (reference XII-3).

Emulsion: Colloidal mixture of two immiscible fluids, one being dispersed in the other in the form of fine droplets.

Flow regime: The physical geometry exhibited by a multiphase flow in a conduit; for example, liquid occupying the bottom of the conduit with the gas phase flowing above, or a liquid phase with bubbles of gas.

Fluid: A substance readily assuming the shape of the container in which it is placed; e.g. oil, gas, water or mixtures of these.

Gas: Hydrocarbons in the gaseous state at the prevailing temperature and pressure.

Gas-liquid-ratio (GLR): The gas volume flow rate, relative to the total liquid volume flow rate (oil and water), all volumes converted to volumes at standard pressure and temperature.

Gas-oil-ratio (GOR): The gas volume flow rate, relative to the oil volume flow rate, both converted to volumes at standard pressure and temperature.

Gas volume fraction (GVF): The gas volume flow rate, relative to the multiphase volume flow rate, at the pressure and temperature prevailing in that section. The GVF is normally expressed as a percentage.

Hold-up: The cross-sectional area locally occupied by one of the liquid phases of a multiphase flow relative to the cross-sectional area of the conduit at the same local position.

Homogeneous multiphase flow: A multiphase flow in which all phases are evenly distributed over the cross-section of a closed conduit; i.e. the composition is the same at all points.

Mass flow rate: The mass of fluid flowing through the cross-section of a conduit in unit time.

Multiphase flow: Two or more phases flowing simultaneously in a conduit- this document deals in particular with multiphase flows of oil, gas and water.

Multiphase flow rate: The total amount of the two or three phases of a multiphase flow flowing through the cross-section of a conduit in unit time. The multiphase flow rate should be specified as multiphase volume flow rate or multiphase mass flow rate.

Multiphase flow velocity: The flow velocity of a multiphase flow. It may also be defined by the relationship (Multiphase volume flow rate / Pipe cross-section).

Multiphase flow rate meter: A device for measuring the flow rate of a multiphase flow through a cross-section of a conduit. It is necessary to specify whether the multiphase flow rate meter measures the multiphase volume or mass flow rate.

Multiphase fraction meter: A device for measuring the phase area fractions of oil, gas and water of a multiphase flow through a cross-section of a conduit.

Multiphase meter: A device for measuring the phase area fractions and flow rates of oil, gas and water of a multiphase flow through a cross-section of a conduit. It is necessary to specify whether the multiphase meter measures volume or mass flow rates.

Oil: Hydrocarbons in the liquid state at the prevailing temperature and pressure conditions.

Oil-continuous multiphase flow: multiphase flow of oil/gas/water characterized by the water phase distributed as water droplets surrounded by oil.

Phase: In reference to multiphase measurement - one constituent in a mixture of several. In particular, the term refers to oil, gas or water in a mixture of any number of the three.

Phase area fraction: The cross-sectional area locally occupied by one of the phases of a multiphase flow, relative to the cross-sectional area of the conduit at the same local position.

Phase flow rate: The amount of one phase of a multiphase flow flowing through the cross-section of a conduit in unit time. The phase flow rate may be specified as phase volume flow rate or as phase mass flow rate.

Phase mass fraction: The phase mass flow rate of one of the phases of a multiphase flow, relative to the multiphase mass flow rate.

Phase velocity: The mean velocity of one phase of a multiphase flow at a cross-section of a conduit. It may also be defined by the relationship (Superficial phase velocity * Phase area fraction).

Phase volume fraction: The phase volume flow rate of one of the phases of a multiphase flow relative to the multiphase volume flow rate.

Slip: Term used to describe the flow conditions that exist when the phases have different velocities at a cross-section of a conduit. The slip may be quantitatively expressed by the phase velocity difference between the phases.

Slip ratio: The ratio between two phase velocities.

Slip velocity: The phase velocity difference between two phases.

Superficial phase velocity: The flow velocity of one phase of a multiphase flow, assuming that the phase occupies the whole conduit by itself. It may also be defined by the relationship (Phase volume flow rate / Pipe cross-section).

Velocity profile: The mean velocity distribution of a fluid at a cross-section of a conduit. The velocity profile may be visualized by means of a two- or three-dimensional graph.

Void fraction: The cross-sectional area locally occupied by the gas phase of a multiphase flow relative to the cross-sectional area of the conduit at the same local position.

Volume flow rate: The volume of fluid flowing through the cross-section of a conduit in unit time at the pressure and temperature prevailing in that section.

Water-continuous multiphase flow: A multiphase flow of oil/gas/water characterized by the oil phase being distributed as oil droplets surrounded by water. Electrically, the mixture acts as a conductor.

Water cut (WC): The water volume flow rate, relative to the total liquid volume flow rate (oil and water), both converted to volumes at standard pressure and temperature. The WC is normally expressed as a percentage.

Water-in-liquid ratio (WLR): The water volume flow rate, relative to the total liquid volume flow rate (oil and water) at the pressure and temperature prevailing in that section.

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APPENDIX 3 - SURVEY FORMS, PERFORMANCE SPECIFICATIONS

1. **Multiphase Metering Systems - Vendor Specifications (p. 1)**
2. **Wet Gas Metering Systems – Vendor Specifications (p. 2)**
3. **Multiphase Metering Systems – Performance Questionnaire (p. 3-7)**
4. **Wet gas Metering Systems – Performance Questionnaire (p. 8-12)**

Multiphase Metering System -Vendor Information/Specification

Vendor (contact person):
Phone: **Fax:**
Email:
Metering System Designation:

10.0	**Mechanical**				
10.1	Size Range- Inch(mm)	2"	3"	4"	8"
10.2	Flow Capacity Liquid - BPD				
10.3	Flow Capacity Gas - MSCF/D				
10.4	ANSI Rating Available for this size				
10.5	Operating Temperature -Range				
20.0	**Type of Meter System**				
20.1	**Fluid Conditionening:**				
20.2	NS-entire flow stream is measured at the same time				
20.3	PS- flow sream is split, each measured separately				
20.4	FS- one or more phases is fully separated				
20.5	MX - some form of mixing is used ahead of the meter				
20.6	Others				
21.0	**Phase Velocity Determination**				
21.1	Venturi				
21.2	Cross Correlation using:				
21.3	Gas phase - method used				
21.4	Liquid phase - method used				
21.5	Others				
22.0	**Composition (Phase)- Determination**				
22.1	Densitometer - Type				
22.2	Dielectric - Type				
22.3	Others				
30.0	**Relative Error (%flow rate) - Operating Range**	Oil	Water	Gas	WC
30.1	GVF = 0-80%				
30.2	GVF = 80-95%				
30.3	GVF = 95-99%				
30.4	WC = 0-60%				
30.5	WC = 60-80%				
30.6	WC =80-100%				
30.7	Salinity = 0-6000 ppm				
30.8	Salinity = 6000-20,000 ppm				
30.9	Salinity = 20,000-50,000 ppm				
30.11	Viscosity= 0-100 Centipoises				
30.12	Viscosity= 100-1000 Centipoises				
30.13	Viscosity= 1000-10,000 Centipoises				
30.14	Sand content up to ----% by volume				
40.0	**For the Above Performance Accuracy:**				
40.1	Meter automatically adjusts for salinity				
40.2	Salinity data is entered by calibration/manually				
40.3	Meter automatically adjusts for viscosity				
40.4	Viscosity data is entered by calibration/manually				
40.5	Accuracy if,fluid property changes are not corrected				

Wet Gas Metering System -Vendor Information/Specification

Vendor (contact person):
Phone: **Fax:**
Email:
Metering System Designation:

10.0 Mechanical

10.1 Size Range- Inch(mm)			
10.2 Flow Capacity Liquid - BBL/MMSCF			
10.3 Flow Capacity Gas - MMSCF/D			
10.4 ANSI Rating Available for this size			

10.5 Operating Temperature -Range

20.0 Type of Meter System - Check the conditions
20.1 Type I - Wet Gas Condition
20.2 LM = 0.02 @ operating conditions
20.3 GVF = 99.5% or higher
20.4 Measurement Device: Oriifce, Venturi, Vortex, Utrasonic, etc.
20.5 Method of estimating the liquid content:
20.6 Liquid correction per:
21.0 Type II - Wet Gas conditions
21.1 LM = 0.3 @ operating conditions
21.2 GVF = 99.0% or higher
21.3 Measurement Device: Dual Venturi, Venturi/Vortex, Inverted Venturi, etc.
21.4 Liquid Determined by:
21.5 Tracer Technique
21.6 Periodic Sampling
21.7 on-line measurements
21.8 Others
21.9 Liquid correction is made per:
22.0 Type III - Wet Gas conditions
22.1 LM higher than 0.30 @ operating conditions
22.2 GVF = 95% or higher
22.3 ***See Questionnaire on Multiphase Metering Systems***

30.0 Relative Error (%flow rate) - Operating Range	Gas	Liquid	WC
30.1 LM range			
30.2 GVF Range			
30.3 LGR Range			
30.4 WC range			
40.0 For the Above Performance Accuracy:			
40.1 Meter automatically adjusts to fluid properties: Yes No			
40.2 API gravity is corrected per:			
40.3 Produced Water SG is corrected per:			
40.4 Viscosity changes are corrected per:			
40.5 Other fluid property changes are corrected per:			
40.6 above Fluid Properties are entered by calibration/manually			
40.7 Other fluid property changes are corrected per:			
40.8 If fluid property changes are not corrected, the impact on accuracy is:			
40.9 Sand content of -----%by volume will affect the accuracy by:			

Company:	Applications contact:	Service contact:
Address:	Address	Address
Telephone #	Telephone	Telephone
Fax #	Fax	Fax
Email	Eamil	Eamil
Web site	Web site	Web site

100	**Documentation provided.**	Yes	No	Extra charge					Comment
101	**Manuals**								
	Theory of operation								
	Installation - Maintenance								
	Commissioning								
	How to operate								
102	**PID (Process Instrument Diagram)**								
103	**BOM (Bill of material)**								
	Vendor part numbers								
	Instrument part numbers								
104	**Instrument data sheets (not "cut" sheets)**								
105	**Application sheet that system was designed for**								
106	**Certifications**								
	Cenelec/UL/Coast guard/British Standards/etc.								
200	**Product support**	Yes		No		Yes		No	
201	**During design**	Office	Site	Office	Site	Office	Site	Office	Site
	Coordination meetings								
	FAT with customer present								
	Training								
201	**During shipment**								
	Coordination with customer purchasing								
203	**During Installation and Commissioning**	Domestic USA including Alaska				Outside the USA and Alaska			
	Applications eng								
	Service engineer								
	Software								
204	**During standard warranty**								
	Applications eng								
	Service engineer								
	Parts								
	Labor								
	Software upgrades								
205	**During extended warranty (purchased)**								
	Applications eng								
	Service engineer								
	Parts								
	Labor								
	Software upgrades								
206	**After warrranty expiration**								
	Applications eng								
	Service engineer								
	Parts								
	Labor								
	Software upgrades								
207	**Spare parts support**	Mechanical				Electronic			
	Years after shipment								Guaranteed parts support after shipment

300	Performance - Loop Test	Test 1	Test 2	Test 3	Test 4
301	Location				
302	Agency/Company				
303	Meter Designation				
304	Test Loop Description				
	304.3 **Nom pressure**				
	304.4 **Nom temperature**				
	304.5 **Fluid parameters**				
	304.5.1 **Oil**				
	304.5.1.1 API				
	304.5.1.2 Mol wt				
	304.5.1.3 cp/temp				
	304.5.1.4 other				
	304.5.2 **Water**				
	304.5.2.1 SG				
	304.5.2.2 ppm salt				
	304.5.2.3 Temperature				
	304.5.3 **Gas**				
	304.5.3.1 Mol wt				
	304.5.3.2 SG				
	304.5.3.3 "Z"				
	304.5.4 **WC**				
	304.5.4.1 min				
	304.5.4.2 max				
	304.5.5 **GVF**				
	304.5.5.1 min				
	304.5.5.2 max				
	304.6 **Fluid rates**				
	304.6.1 **Oil**				
	304.6.1.1 min				
	304.6.1.2 max				
	304.6.2 **Water**				
	304.6.2.1 min				
	304.6.2.2 max				
	304.6.3 **Gas**				
	304.6.3.1 min				
	304.6.3.2 max				
305	Number of				
	305.1 **Test points**				
306	Accuracy -Range of results %				
	306.1 **Oil rate**				
	306.1.1 Max				
	306.1.2 Min				
	306.2 **Water rate**				
	306.2.1 Max				
	306.2.2 Min				
	306.3 **Gas rate**				
	306.3.1 Max				
	306.3.2 Min				
	306.4 **WC**				
	306.4.1 Max				
	306.4.2 Min				
	306.5 **GVF**				
	306.5.1 Max				
	306.5.2 Min				
307	Test/evaluation duration				
308	Report available				
	308.1 **Yes**				
	308.2 **No**				
309	Data available				
	309.1 **Yes**				
	309.2 **No**				
310	Reference System Accuracy 310.1 Oil rate 310.2 Water rate 310.3 Gas rate 310.4 WC				

400	Operational - Field Test	Location 1	Location 2	Location 3	Location 4
401	**Location**				
402	**Agency/Company**				
403	**Metering System Designation**				
404	**Process**				
	404.1 **Surface**				
	404.2 **Sub sea**				
	404.2.1 Depth				
	404.3 **Nom pressure**				
	404.4 **Nom temperature**				
	404.5 **Fluid parameters**				
	404.5.1 **Oil**				
	404.5.1.1 API				
	404.5.1.2 Mol wt				
	404.5.1.3 cp/temp				
	404.5.1.4 other				
	404.5.2 **Water**				
	404.5.2.1 SG				
	404.5.2.2 ppm salt				
	404.5.2.3 Temperature				
	404.5.3 **Gas**				
	404.5.3.1 Mol wt				
	404.5.3.2 SG				
	404.5.3.3 "Z"				
	404.5.4 **WC**				
	404.5.4.1 min				
	404.5.4.2 max				
	404.5.5 **GVF**				
	404.5.5.1 min				
	404.5.5.2 max				
	404.6 **Fluid rates**				
	404.6.1 **Oil**				
	404.6.1.1 min				
	404.6.1.2 max				
	404.6.2 **Water**				
	404.6.2.1 min				
	404.6.2.2 max				
	404.6.3 **Gas**				
	404.6.3.1 min				
	404.6.3.2 max				
405	**Number of**				
	305.1 **Test points**				
	305.2 **No. of Wells**				
406	**Accuracy -Range of results %**				
	406.1 **Oil rate**				
	406.1.1 Max				
	406.1.2 Min				
	406.2 **Water rate**				
	406.2.1 Max				
	406.2.2 Min				
	406.3 **Gas rate**				
	406.3.1 Max				
	406.3.2 Min				
	406.4 **WC**				
	406.4.1 Max				
	406.4.2 Min				
	406.5 **GVF**				
	406.5.1 Max				
	406.5.2 Min				
407	**Test/evaluation duration**				
408	**Report available**				
	408.1 **Yes**				
	408.2 **No**				
409	**Data available**				
	409.1 **Yes**				
	409.2 **No**				
410	**Reference system**				
	410.1 Atmospheric tank				
	410.2 2 Phase separator				
	410.3 3 Phase separator				
	410.4 Other				

500	**Environmental**	
	501 **Ambient temperature - process instrument**	
	501.1 **High**	
	501.2 **Low**	
	502 **Ambient temperature - Display device**	
	502.1 **High**	
	502.2 **Low**	
	503 **Process temperature - process instrument**	
	503.1 **High**	
	503.2 **Low**	
	504 **Cover required**	
	504.1 **Process instrument**	
	504.1.1 Sun shield	
	504.1.2 Rain shield	
	504.1.3 Building	
	504.2 **Display instrument**	
	504.2.1 Sun shield	
	504.2.2 Rain shield	
	504.2.3 Building	
	505 **Rain**	
	505.1 **Falling**	
	505.2 **Wind driven**	
	506 **Dust resistant**	
	507 **Relative humidity**	
	507.1 **Non-condensing**	
	507.2 **Condensing**	
	508 **Vibration**	
	508.1 **Process**	
	508.2 **Display**	
600	**Electrical**	
	601 **What is the area classification certification of the display portion?**	
	602 **What is the area classification certification of the process portion?**	
	603 **What input power is required for the process portion and the display portion?**	
	604 **What is the typical electrical power consumed?**	
	605 **What is the voltage transient withstand on the power lines?**	
	606 **What is the voltage transient withstand on the instrument lines?**	
	607 **What is the voltage transient withstand on the communication lines?**	
700	**Communication**	
	701 **What communication protocols are developed and ready for use?**	
	702 **What distance can separate the process and display units at what baud rates?**	
	703 **What cableing is required for communication?**	
	704 **What cableing is required for other hookup?**	
800	**Software and computers**	
	801 **How are calibration factors and changes tracked for retention and audit purposes?**	
	802 **How track software model changes made and tracked if done at site?**	
	803 **Are calibration factor changes and software model changes kept at the factory referenced to the specific meter?**	
900	**Piping Requirements**	
	901 **What are the installation requirements for the following configurations**	
	901.1 **assume control valve up- stream**	
	901.2 **assume control valve down stream**	
	901.3 **assume chole valve up- stream**	
	901.4 **assume choke l valve downstream**	
	902 **Specify valving and piping requirements around the metering system**	

1000 Factory Acceptance Tests

1001.1	**Do you have an established procedure for FAT**	**Yes**	**No**	
1001.2	Test matrix used and no. of test points			
1001.3	**Range of parameters tested;**	**Min**	**Max**	**Comments**
1001.4	GVF			
1001.5	WC			
1001.6	Liquid Flow Rates			
1001.7	Gas Flow Rates			
1001.8	Others			
1001.9	**Reference Accuracy for FAT**			
1002.0	Oil rate			
1002.1	water rate			
1002.2	gas rate			
1002.3	WC			
1002.0	**How is the reference verified**			
1003.0	**Is the FAT document available to API Task Group**	**Yes**	**No.**	

1100 After Commissionening,how do you verify the accuracies for the following:

		Min	Max	
1101	**Rate**			
1101.1	Total liquid rate			
1101.2	Total gas rate			
1101.3	Oil rate			
1101.4	Water rate			
1101.5	Water cut			
1101.6	GVF - Gas volume fraction at the meter			
1101.7	What referennce you use			

1102 **After the measurement system has been commissioned how does it react to**

		+/- 10% Salinity change		+/- 5% Oil density change		+/- 5% gas mol wt change	
	Rate	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**
1102.1	Total liquid rate						
1102.2	Total gas rate						
1102.3	Oil rate						
1102.4	Water rate						
1102.5	Water cut						
1102.6	GVF - Gas volume fraction at the meter						
1102.7	What reference do you use to verify						

Company:	Applications contact:	Service contact:
Address:	Address	Address
Telephone #	Telephone	Telephone
Fax #	Fax	Fax
Email	Eamil	Eamil
Web site	Web site	Web site

100	Documentation provided.	Yes	No	Extra charge	Comment
101	**Manuals**				
	Theory of operation				
	Installation - Maintenance				
	Commissioning				
	How to operate				
102	**PID (Process Instrument Diagram)**				
103	**BOM (Bill of material)**				
	Vendor part numbers				
	Instrument part numbers				
104	**Instrument data sheets (not "cut" sheets)**				
105	**Application sheet that system was designed for**				
106	**Certifications**				
	Cenelec/UL/Coast guard/British Standards/etc.				

200	Product support	Yes		No		Yes		No		
201	**During design**	Office	Site	Office	Site	Office	Site	Office	Site	
	Coordination meetings									
	FAT with customer present									
	Training									
201	**During shipment**									
	Coordination with customer purchasing									
203	**During Installation and Commissioning**	Domestic USA including Alaska				Outside the USA and Alaska				
	Applications eng									
	Service engineer									
	Software									
204	**During standard warranty**									
	Applications eng									
	Service engineer									
	Parts									
	Labor									
	Software upgrades									
205	**During extended warranty (purchased)**									
	Applications eng									
	Service engineer									
	Parts									
	Labor									
	Software upgrades									
206	**After warrranty expiration**									
	Applications eng									
	Service engineer									
	Parts									
	Labor									
	Software upgrades									
207	**Spare parts support**	Mechanical				Electronic				
	Years after shipment									Guaranteed parts support after shipment

1000 Performance - Loop Test		Test 1	Test 2	Test 3	Test 4
1001	**Location**				
1002	**Agency/Company**				
1003	**Meter Designation - Type**				
1004	**Loop Description**				
1004.3	**Nom pressure**				
1004.4	**Nom temperature**				
1004.5	**Fluid parameters**				
1004.5.1	**Oil**				
1004.5.1.1	API				
1004.5.1.2	Mol wt				
1004.5.1.3	cp/temp				
1004.5.1.4	other				
1004.5.2	**Water**				
1004.5.2.1	SG				
1004.5.2.2	ppm salt				
1004.5.2.3	Temperature				
1004.5.3	**Gas**				
1004.5.3.1	Mol wt				
1004.5.3.2	SG				
1004.5.3.3	"Z"				
1004.5.4	**WC**				
1004.5.4.1	min				
1004.5.4.2	max				
1004.5.5	**GVF**				
1004.5.5.1	min				
1004.5.5.2	max				
1004.6	**Fluid Rates- Range**				
1004.6.1	**Oil**				
1004.6.1	min				
1004.6.2	max				
1004.6.2	**Water**				
1004.6.2.1	min				
1004.6.2.2	max				
1004.6.3	**Liquid**				
1004.6.3.1	min				
1004.6.3.2	max				
1004.6.4	**Gas**				
304.6.3.1	min				
304.6.3.2	max				
1005	**Number of**				
1005.1	**Test points**				
1006	**Range of Accuracy %**				
1006.1	**Oil rate**				
1006.1.1	Max				
1006.1.2	Min				
1006.2	**Water rate**				
1006.2.1	Max				
1006.2.2	Min				
1006.3	**Liquid rate**				
1006.3.1	Max				
1006.3.2	Min				
1006.4	**Gas rate**				
1006.4.1	Max				
1006.4.2	Min				
1006.5	**WC**				
1006.5.1	Max				
1006.5.2	Min				
1006.6	**GVF**				
1006.6.1	Max				
1006.6.2	Min				
1007	**Test/evaluation duration**				
1008	**Report available**				
1008.1	**Yes**				
1008.2	**No**				
1009	**Data available**				
1009.1	**Yes**				
1009.2	**No**				
1010	**Reference System Accuracy**				
1010.1	Oil rate				
1010.2	Water rate				
1010.3	Gas rate				
1010.4	WC				

1100	Operational - Field TestsSystem	Location 1	Location 2	Location 3	Location 4
1101	Location				
1102	Operator/Company				
1103	Type of Meter				
1104	Test Site				
	1104.1 Surface				
	1104.2 Subsea				
	Depth				
	1104.3 Nom pressure				
	1104.4 Nom temperature				
	1104.5 Fluid parameters				
	1104.5.1 Oil				
	1104.5.1.1 API				
	1104.5.1.2 Mol wt				
	1104.5.1.3 cp/temp				
	1104.5.1.4 other				
	1104.5.2 Water				
	1104.5.2.1 SG				
	1104.5.2.2 ppm salt				
	1104.5.2.3 Temperature				
	1104.5.3 Gas				
	1104.5.3.1 Mol wt				
	1104.5.3.2 SG				
	1104.5.3.3 "Z"				
	1104.5.4 WC				
	1104.5.4.1 min				
	1104.5.4.2 max				
	1104.5.5 GVF				
	1104.5.5.1 min				
	1104.5.5.2 max				
	1104.6 Fluid rates				
	1104.6.1 Oil				
	1104.6.1.1 min				
	1104.6.1.2 max				
	1104.6.2 Water				
	1104.6.2.1 min				
	1104.6.2.2 max				
	1104.6.3 Liquid				
	1104.6.3.1 min				
	1104.6.3.2 max				
	1104.6.3 Gas				
	1104.6.3.1 min				
	1104.6.3.2 max				
1105	Number of				
	1105.1 Test points				
	1105.2 No. of Wells				
1106	Accuracy of results %				
	1106.1 Oil rate				
	1106.1.1 Max				
	1106.1.2 Min				
	1106.2 Water rate				
	1106.2.1 Max				
	1106.2.2 Min				
	1106.3 Water rate				
	1106.3.1 Max				
	1106.3.2 Min				
	1106.4 Gas rate				
	1106.4.1 Max				
	1106.4.2 Min				
	1106.5 WC				
	1106.5.1 Max				
	1106.5.2 Min				
	1106.6 GVF				
	1106.6.1 Max				
	1106.6.2 Min				
1107	Test/evaluation duration				
1108	Report available				
	1108.1 Yes				
	1108.2 No				
1109	Data available				
	1109.1 Yes				
	1109.2 No				
1110	Reference system - Accuracy				
	1110.1 3-phase Separator				
	1110.2 2-phase separator				
	1110.3 Choke				
	1110.4 Others				

1200	Environmental requirements for the system	
	1201 **Ambient temperature - process instrument**	
	1201.1 **High**	
	1201.1 **Low**	
	1202 **Ambient temperature - Display device**	
	1202.1 **High**	
	1202.1 **Low**	
	1203 **Process temperature - process instrument**	
	1203.1 **High**	
	1203.1 **Low**	
	1204 **Cover required**	
	1204.1 **Process instrument**	
	1204.1.1 Sun shield	
	1204.1.2 Rain shield	
	1204.1.3 Building	
	1204.2 **Display instrument**	
	1204.2.1 Sun shield	
	1204.2.2 Rain shield	
	1204.2.3 Building	
	1205 **Rain**	
	1205.1 **Falling**	
	1205.2 **Wind driven**	
	1206 **Dust resistant**	
	1207 **Relative humidity**	
	1207.1 **Non-condensing**	
	1207.2 **Condensing**	
	1208 **Vibration**	
	1208.1 **Process**	
	1208.2 **Display**	
1300	**Electrical**	
	1301 **What is the area classification certification of the display portion?**	
	1302 **What is the area classification certification of the process portio**	
	1303 **What input power is required for the process portion and the display portion?**	
	1304 **What is the typical electrical power consumed?**	
	1305 **What is the voltage transient withstand on the power lines?**	
	1306 **What is the voltage transient withstand on the instrument lines?**	
	1307 **What is the voltage transient withstand on the communication lines?**	
1400	**Communication**	
	1401 **What communication protocols are developed and ready for us**	
	1402 **What distance can separate the process and display units at what baud rates?**	
	1403 **What cableing is required for communication?**	
	1404 **What cableing is required for other hookup**	
1500	**Software and computers**	
	1501 **How are calibration factors and changes tracked for retention and audit purposes?**	
	1502 **How track software model changes made and tracked if done at site?**	
	1503 **Are calibration factor changes and software model changes kept at the factory referenced to the specific meter?**	
1600	**Piping Requirements**	
	1601 **What are the installation requirements for the following configurations**	
	1602 **assume control valve up- stream**	
	1603 **assume control valve down stream**	
	1604 **assume chole valve up- stream**	
	1605 **assume choke l valve downstream**	
	1606 **Specify valving and piping requirements around the metering system**	

1700 Factory Acceptance Tests

1701.1 **Do you have an established procedure for FAT** Yes No

1701.2 Test matrix used and no. of test points

	Min	Max	Comments
1701.3 **Range of parameters tested**			
1701.4 GVF			
1701.5 WC			
1701.6 Liquid Flow Rates			
1701.7 Gas Flow Rates			
1701.8 Others			
1701.9 **Reference Accuracy for FAT**			

1702.0 Oil rate

1702.1 water rate

1702.2 gas rate

1702.3 WC

1702.4 **How is the reference verified**

1703.0 **Is the FAT document available to API Task Group** Yes No.

After Commissionening,how do you verify the accuracies for the following:

1704 Rate	Min	Max	Comments
1704.1 Total liquid rate			
1704.2 Total gas rate			
1704.3 Oil rate			
1704.4 Water rate			
1704.5 Water cut			
1704.6 GVF - Gas volume fraction at the meter			
1704.7 What referennce you use			

1705 **After the measurement system has been commissioned how does it react**

	+/- 10% Salinity change		+/- 5% Oil density change		+/- 5% gas mol wt change	
Rate	Min	Max	Min	Max	Min	Max
1705.1 Total liquid rate						
1705.2 Total gas rate						
1705.3 Oil rate						
1705.4 Water rate						
1705.5 Water cut						
1705.6 GVF - Gas volume fraction at the meter						
1705.7 What reference do you use to verify						

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