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MULTIPHASE FLOW METERING TECHNOLOGY UPDATED

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Abstract

Multiphase flow metering can be understood as the measurement at line conditions of the component volumetric rates of a multiphase flow stream without its compulsory separation or sampling. For oil well test applications, multiphase flow metering is the measurement of the oil, water and gas flow rates of the produced fluids, without the usage either of a two-phase or a three-phase separator. In comparison to conventional gravity-separator well test systems, multiphase flow metering allows shorter-duration, more accurate tests and less operator oversight for well tests. Additionally, multiphase flow meters have lower capital and operating costs for offshore and subsea applications. In the oil industry, the main goals of multiphase flow meters are: (a) to replace test separator vessels, (b) to avoid installation of production test lines and test headers (both in subsea and topside applications) and, (c) to improve the well data acquisition by improving the accuracy and frequency of oil well tests. Typical output results from a multiphase meter are the flow rates and the volumetric fractions of each phase (mass quality and water cut). Several physical principles have been applied to multiphase metering concepts, which are characterized by the combination of techniques used. No simple type of meter or metering system can cover all applications, so there is clearly room for more development and optimization. Recently, the research has been focused more on modeling and artificial intelligence approaches. Besides, there is a permanent need of installing multiphase meters along the down-hole environment of the oil wells or at the well christmas-trees, not yet achieved but with many ongoing projects. This paper intends to present the major advances in the multiphase flow metering technology which impacts directly on the final performance of the measurement process.

1 WORLDWIDE TECHNOLOGY OVERVIEW

Multiphase flow metering can be understood as the measurement at line conditions of the component volumetric rates of a multiphase flow stream without its compulsory separation or sampling. For oil well test applications, multiphase flow metering is the measurement of the oil, water and gas flow rates of the produced fluids from a well, without the usage either of a two-phase or a three-phase separator. In comparison to conventional gravity-separator well test systems, multiphase flow metering allows shorter-duration and more accurate well tests, with less operator supervising. Additionally, multiphase flow meters have lower capital and operating costs for offshore and subsea applications.

This technology started to be developed in the 80's as a response from the universities and R&D institutions to the guided demands set by the petroleum industry and it has been boosted by the subsea engineering development because of the need to implement subsea installations at a cost effective basis, once a large part of the world's hydrocarbon reserves lie in water depths greater than 500 m and newer discoveries tend to increase oil production up to 3,000 m WD. Also, as the requirements of minimum facilities in production systems increase, for instance, in unmanned platforms and onshore stations, there is a need for simple robust multiphase flow meters, preferably at lower costs.

Multiphase flow meters are currently becoming accepted by the industry and their applicability is expected to increase once the prices decrease on account of the manufacturers' competitiveness and the operators' confidence. In 1998, there were 35 operators using multiphase meters with a total number of 164 meters already installed for well testing, 20 of which for subsea application [1]. In 1999, this number increased to 275, 38 being for subsea installation.

In Brazil, multiphase meters have started to be used in both topside and subsea applications, as shown in Tables 1 and 2.

In the oil industry, the main goals expected from the employment of multiphase flow meters are: (a) to replace test separators, (b) to avoid installation of test lines and test headers (both in subsea and topside applications) and, (c) to improve the well data acquisition (by improving the accuracy and frequency of well tests). The requirements for these meters are likely to be focused on four main areas:

- *Reservoir Management* – the oil recovery from a field can be improved in the long term by continuous monitoring of the flow rates at each well; a possible overall uncertainty of the reservoir monitoring using the conventional systems (test separator, each well being tested once a month, further data processing, etc.) could lead to a 10 % level; the ideal situation would be for each well to have its individual multiphase flow meter in order to increase the quality and quantity of the information available to the reservoir engineers.
- *Custody Transfer Metering* – the production from one oil field can be mixed with the production from another, the owners of both being different; the accuracy expected from flow rate measurement would be about 5 % of the measured value.
- *Process Control* – when gas lift pumping or vapour injection is used, it is necessary to know the efficiency of the process; here, also the accuracy expected from flow rate measurement would be about 5 % of the measured value, as the trending of the variables is more important than their actual values for control purposes.
- *Fiscal Metering* – much work has to be done in this area because of the high accuracy level requirements (typically $\pm$ 0.25% for oil and $\pm$ 1% for natural gas), which do not fit into the available multiphase meters profile yet; according to the present scenario of multiphase meter uncertainty, it is only possible to have negotiation between parts, taking into account the field economics.

Multiphase flow systems are difficult to predict because they combine turbulent flows with often highly complex interfaces. An understanding of such flows is only obtainable by experimental observations and measurements.

Various ways have been proposed to show how the multiphase flow characteristics of a well or a field change with time and to show the operating envelopes of multiphase meters. Commonly, useful forms are the two-phase plot of liquid flow rate against gas flow rate and the plot of water cut against gas volume fraction.

In a multiphase metering system it is necessary to make n-1 independent measurements simultaneously, in order to determine the fractions of n components in a homogeneous mixture. The n-1 measurements will give n-1 independent equations and the additional equation needed to obtain an unique solution is $SF_i=1$, where F_i is volume fraction of the different components in the mixture. Typical output results from a multiphase meter are the flow rates and the volumetric fractions of each phase (gas volume fraction and water cut).

The most common approach in multiphase flow metering is the simultaneous phase fraction and velocity measurements, sometimes with mixture density measurement.

Table 1. *Petrobras* Subsea Production Manifolds Equipped with Multiphase Meters

FIELD	WD (m)	SPU	NUMBER OF SUBSEA MANIFOLDS	MANIFOLD FABRICATION	MULTIPHASE METERS		DEPLOYED	FIRST OIL
					FORESEEN	INSTALLED		
Marlim	860	P-35 FPSO	2	CBV (Brazil)	2	-		Feb. / 2000
	905	P-37 FPSO	3 (obs. 1)	ABB (Brazil)	1	-		Dec. / 2000
Marimbá	429	P-8 SS	1	KVAERNER (Brazil)	1	-	Nov. / 99	Jan./ 2000
RJS-396 well area	900		1	(under bidding)	1	-		Oct. / 2001
Albacora	500	P-31 FPSO	4	CBV (Brazil)	4 (obs. 2)	1	Jun. / 97	May / 99
Roncador	1800	P-36 SS	1	CBV (Brazil)	1 (obs. 3)	-		Jan. / 2001
Marimbá Leste/ Espadarte	700	FPSO-6	1	(under bidding)	1	-		Aug. / 2001

OBS:
1. Only one manifold with multiphase meter;
2. Two multiphase meters already selected;
3. Six meters for gas/condensate.

Table 2. *Petrobras* Multiphase Meters Installed and/or Under Testing

PROJECT	DESIGN	SIZE (inch)	YEAR	TYPE OF SERVICE	POWER SUPPLY	INSTRUMENTATION	OPERATION CONDITIONS
Atalaia	Subsea	3	1996-97	Qualification Test	120 Vac 1160 W	Gamma, Capacitor, Venturi	10 bar 50-90% GVF 0-50% WC
	Topside	2	1997-98	Test	120 Vac 80 W	Gamma, Capacitor, Inductive, Venturi	10 bar 0-100% GVF 0-100% WC
	Topside	2	1998- 99	Qualification Test	120 Vac 80 W	Dual Energy Gamma Ray, Venturi	10 bar 0-100% GVF 0-100% WC
	Topside	4	2000	Qualification Test	120 Vac 80 W	Dual Energy Gamma Ray	10 bar 5-95% GVF 0-100% WC
	Subsea	3	2000	Qualification Test	120 Vac 80 W	Dual Energy Gamma Ray, Venturi	10 bar 0-100% GVF 0-100% WC
Albacora	Subsea	3	1998-99	Well Testing	120 Vac 1160 W	Gamma, Capacitor, Venturi	60 bar 60-80% GVF 0-50% WC
Albacora	Subsea	3	99-2000	Well Testing	120 Vac 1160 W	Gamma, Venturi	60 bar 60-80% GVF 0-50% WC
Barracuda	Topside	6	1998-99	Well testing	120 Vac 130 W	Gamma, Capacitor, Venturi	7.5 bar 90-96% GVF 0% WC
Guaricema	Topside	2	1998-99	Well testing	24 Vdc 13 W	Gamma, Capacitor, Venturi	7.5 bar 90-96% GVF 0% WC
Vermelho	Topside	2	2000	Well testing	120 Vac 80 W	Dual Energy Gamma Ray, Venturi	7.5 bar % GVF % WC
Carapeba	Topside	2	2000	Well testing	120 Vac 80 W	Gamma, Inductive, Capacitor, Venturi	7.5 bar % GVF % WC

All ongoing industrial schemes use a combination of instrumentation techniques and the number of transducers and the duty which they will be expected to perform will depend upon the way they are combined, possibly in conjunction with other devices such as homogenizers and samplers and sometimes with additional modelling (slip modelling, etc.). If homogenization is applied, the requirement for calibration may be reduced, thus widening the choice of instruments. If the fluid is not homogeneous (i.e. each component is moving at a different velocity), the system may require more sophisticated measurements from which individual component velocities and hold-up (volumetric composition) can be derived.

All available instrument sensors are more or less flow regime dependent, most of them demanding a homogeneous mixture of the components in the measurement volume to obtain measurement stability and acceptable accuracy. Many concepts use mixers to secure homogeneous mixtures and other use gas partial separation in order to increase accuracy, once it is difficult to obtain it for the liquid flow rates working with high gas fractions. The essential point is that the fast fluctuations in multiphase flow carry most of the information. The signals from sensors used in most metering applications are damped to reduce noise and give a good average value of the measured parameter. By using heavily damped sensors the fine detail is lost with the consequence that high accuracy is unlikely to be achieved.

Several physical principles and methods have been applied to multiphase metering concepts, namely: a) Electrical (impedance, capacitance, inductance); b) Single or dual energy gamma or X-rays attenuation; c) Cross correlation velocity (gamma attenuation, microwave, capacitance); d) Differential pressure (Venturi, mixer device); e) Positive displacement; f) Pulsed neutron activation (PNA) & Neutron interrogation; g) Tomography; h) Partial separation.

The different meter concepts are characterized by the combination of the techniques used. Each combination has its advantages and limitations, making each favourable under certain conditions determined by the process where the meter is to be used, such as expected component ratios, production rates, type of crude, variation in permittivity, conductivity and density, presence of sand in the flow, need of pigging, need to avoid pressure drop and others.

No simple type of meter or metering approach can cover all applications so there is clearly room for more development. In addition to issues of accuracy calculation, standardization and field practice, a number of technical issues still remain. Special niches may be worth examining, such as wet gas measurement, heavy crude with very low gas volume fractions, oil flows with the presence of sand or other contaminant (salt, H_2S, etc.), high water cut flows and others.

Some concepts of multiphase metering in the down-hole environment are under development and based on a combination of conventional sensors (pressure, temperature, inductance, etc.), special sensors (optical, etc.) and modelling (knowledge of reservoir pressure/temperature and inflow performance, multiphase flow in choke valves, etc.) because of the need for a meter in each branch of multilateral wells. The main advantage in metering down-hole is due to the better representivity of the reservoir conditions.

Other projects are trying to apply artificial neural networks in order to predict the liquid and gas flow rates of a multiphase mixture where inner models of the flow evolution in any pipe devices (or in a pipe run only) can be developed.

Four-phase flow metering (gas-oil-water-sand) designs are going to take into account the presence of solids like sand, using techniques which are based on ultrasonic/microwave detection or three-level energy gamma attenuation. Others are attempting to include the measurement of salinity as well.

2 PHYSICAL PRINCIPLES AND METERING TECHNIQUES

In general, a multiphase meter directly or indirectly determines, through its basic instruments, the following properties and parameters: a) measurement of the mixture velocity and/or of each phase; b) fraction measurement in each phase (including *BS&W*); c) measurement of the mixture density. To perform such measurements, the main principles and technologies of components of multiphase meters are described as follows.

2.1 Capacitance

The operating principle of the capacitance-type component is based on two electrodes installed on the inner walls, within the measurement section, opposite each other, for the purpose of measuring the dielectric constant of the mixture. Figure 1 shows the dielectric model [2] of a typical capacitance sensor. The model is formed by different capacitance effects. There is the capacitance between the electrode and the pipe inner wall ($2C_w$), the capacitance (C_p) between the electrodes through the liner, the actual capacitance (C_h) of the multiphase mixture and the capacitance (C_s) resulting from all of the other capacitance effects.

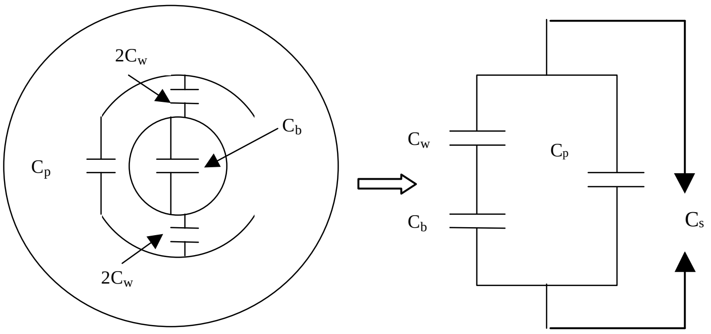

Figure 1. Electric model of the capacitance sensor

It is important to stress that the capacitance-type component only operates in a continuous oil flow regime, as in the case of continuous water regime the multiphase mixture short-circuits the capacitor. The reduction of the inner diameter of the metering section on account of paraffin or other material deposition may affect the meter performance, due to the change in the medium dielectric constant. Another aspect is the segregation of flowing phases which, due to the concentration of water on certain parts of the inner wall of the section may short-circuit the capacitance sensors. In such cases the performance of the component may be optimized by the installation of a highly efficient mixer upstream the component.

2.2 Gamma Ray Attenuation

2.2.1 Single Energy Gamma Ray Attenuation

When a single energy gamma ray attenuation device is used, the objective is to determine the mixture density which is going to be useful in the total multiphase flow rate computation. The gas volume fraction can be also determined. Figure 2 shows an arrangement of a gamma-densitometer [3] for measuring parameters and properties in multiphase, consisting of a radioactive source, collimators, detector and test section. The collimators purpose is to reduce a narrow and unidirectional radiation bundle.

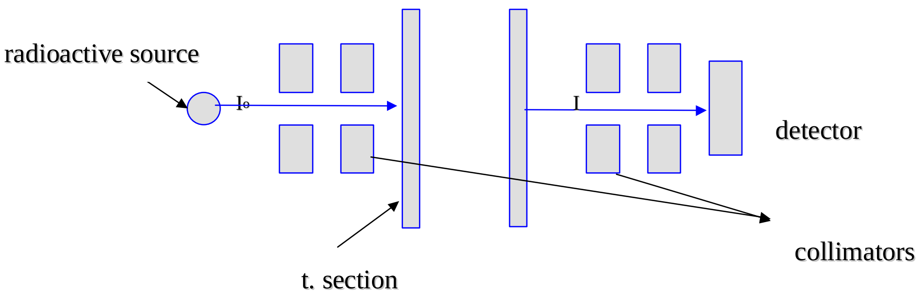

Figure 2. Simplified arrangement of a gamma-densitometer showing the radioactive source, collimators, the test section and the detector.

The density of the mixture is measured by gamma ray densitometer and correlated with the densities of liquid and gas as follows:

$$r_m = \frac{a_g + K(1-a_g)}{\frac{a_g}{r_g} + \frac{K(1-a_g)}{r_l}} \tag{1}$$

where:

r_m - density of the mixture measured by gamma ray densitometer;
α_g - gas volume fraction;
K - gas and liquid velocity ratio;
r_g - density of the gas;
r_l - density of the liquid.

2.2.2 Dual Energy Gamma-ray

When two energy levels [4] of the gamma rays are used, the main purpose is to determine the volumetric fractions of oil, water and gas. The atomic attenuation coefficient depends on the radiation energy and on the atomic number of the material crossed. With two beams of gamma rays with different energies (normally Cesium 137, with gamma ray energy at 662 keV, Americium 241 with 59.5 keV and Barium) two equations may be obtained, one for each energy, out of the three equations necessary to determine the volumetric fractions of oil, water and gas. Such equations appear as shown in (2).

$$- (1/D) \,.\, \mathrm{Ln}(I / I_o) = \mu_o \alpha_o + \mu_w \alpha_w + \mu_g \alpha_g \quad (2)$$

where:

D : inner diameter of the meter piping
I_o : intensity of the radiation measured with vacuum inside the meter
I : intensity of the radiation measured with fluid inside the meter
μ_o, μ_w, μ_g is the coefficient of atomic attenuation of oil, water and gas, respectively
ρ_o , ρ_w, ρ_g is the density of oil, water and gas, respectively
α_o , α_w , α_g is the volumetric fraction of oil, water and gas, respectively.

The third equation is formulated, since it is known that the sum total of volumetric fractions equals one, that is:

$$1 = \alpha_o + \alpha_w + \alpha_g \quad (3)$$

2.3 Inductive

The inductive sensor measures the electrical conductivity of the oil-water mixture when water is the continuous phase. It is constituted of two toroid type devices involving a non conductive liner. The first toroid generates a magnetic field that induces an electrical field in the double phase and, as the environment is conductive, an electrical current will be generated in the fluid. This electrical current in the oil-water mixture consequently induces a voltage in the second toroid according to the Lenz law. By means of a system of automatic control of the very monitor, the electrical current in the fluid is kept constant and equal to the current equivalent to 100% of the water volume fraction, by means of the actuation of the excitation voltage in the main toroid from the reading of the voltage induced in the second toroid.

The electrical conductivity of the oil-water mixture is determined by measuring of the voltage between two electrodes placed between the two toroids and the electric current, that is:

$$\sigma_m = (I_{constant}/\Lambda V)/(L/S) \quad (4)$$

where:

σ_m – electrical conductivity of the environment;
$I_{constant}$ – constant electrical current in the flow;
ΛV – voltage between the electrodes;
S – area of the cross section of the tube;
L = distance between electrodes.

The Measured water volume fraction is a function of the electrical conductivity of the mixture and water. The electrical conductivity of the environment must have a minimum value for the inductive sensor to be applicable. When the oil is the continuous phase, the sensor is not applicable because electrically oil is an insulator. When oil is dispersed in water and not emulsified, the measured water volume fraction will represent the free or continuous water. In the case of oil dispersed in water, but emulsified, the sensor will measure only the free water and not the total water fraction, since it will not detect the emulsified water in oil (because emulsion does not contribute for the electrical current, as described above).

2.4 Microwave by Energy Absorption

The sensor based on microwave by energy absorption uses a measurement section with an electromagnetic oscillator, a transmission antenna and another receptor. In this case, the water fraction is determined by the measurement of electrical properties of the mixture that flows in the measurement section. In parallel, the dielectric constant of the oil/water mixture is measured and compared with data from the internal table of the instrument for temperature, API grade and salinity. Table 3 shows the approximated values of the densities and electrical properties of the oil, gas and water which permit the identification of the phases in a multiphase mixture.

Table 3. Densities and dielectric properties of oil, water and gas

	Oil	Water	Gas
Density (kg/m3)	840	1030	10
Dielectric Constant	2	75	1
Conductivity	10^{-6}	10	0

2.5 Microwave by Resonance Cavity

This sensor has the measurement section as an open resonance cavity, where an electromagnetic field is excited at a characteristic resonance frequency, which is function of the cavity dimensions and of the dielectric constant of the environment (or of the fluid inside the cavity) turning it into an instrument for density measuring. The instrument has an electromagnetic oscillator and two antennas.

2.6 Cross Correlation Techniques

The cross correlation method (Figure 5), used to determine the velocity of a disturbance (for example, gas bubbles in the liquid), correlates the variation in some property of the fluid between two identical sensors of any technology, separated by a pre-defined distance on a straight pipe section (in the direction of the flow). The statistical comparison of the measurements on the first and second sensors enables the determination of the transit time which the mixture spends to move between the two sensors. As the distance between the sensors is known, the mixture velocity in the meter can be measured. The cross correlation function is defined by:

$$R_{xy} = (1/T) \cdot \int_0^T x(t-\iota).y(t)dt \qquad (5)$$

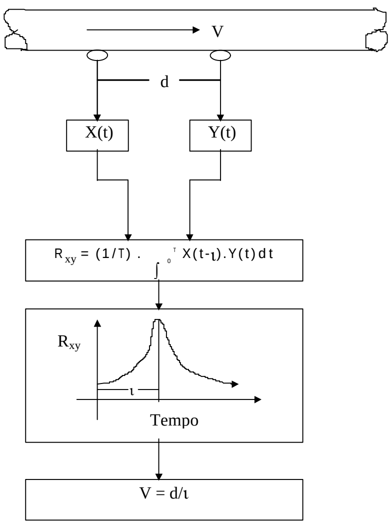

Figure 3. Principle of velocity measurement by the cross correlation method

The distance (d) between the sensors being known, the velocity of the disturbance is determined by:

$$V = d/\iota \qquad (6)$$

Where there is a coincidence of pattern, the cross correlation function reaches the maximum displacement in time.

The two sensors employed to generate the cross correlation function are normally capacitance, microwave or gamma ray devices.

2.7 Positive Displacement

The measurement principle of the positive displacement type component consists in passing a fluid to be measured through one or more chambers of known volume, in a sequential route, within the meter. The fluid itself provokes the movement of the internal parts of the instrument to perform the measurement. The movement of the chambers makes some mechanical rotation effect, by means of gearing or a proximity counter, to count the known volume per time unit. The purpose of the positive displacement component is to determine the total multiphase volumetric flow. Here, the presence of sand and pressure drop effects must be considered.

2.8 Differential Pressure

Several concepts of multiphase meters adopt the differential pressure type component to determine the total speed of the multiphase mixture. The types employed more frequently are the venturi tube, the orifice plate, and the measurement of the differential pressure on a mixer.

The venturi tube contains three important parts: a) the inflow cone (converging) to accelerate the fluid; b) the throat, where low pressure measurements are taken; and c) the outflow cone (diverging), which slows down the fluid, until it reaches a speed equal to approximately 90% of the inflow speed. The measurement of the differential pressure is taken between metering points at the inlet (high) and at the throat (low) of the device. Through the application of the energy equation to a multiphase flow, the mass flow in the venturi meter may be determined by the following equation:

$$dm/dt = (\gamma_g\, \alpha_g + \gamma_o\, \alpha_o + \gamma_w \alpha_w) \,.\, C_D \,.\, E \,.\, A_t \,.\, (2 \,.\, \rho_{3m} \,.\, \Delta p)^{1/2} \qquad (7)$$

where:

γ_g, γ_o, γ_w = f($\Delta p/p$, k, β) = expansion factor of the gas, oil and water respectively ;
α_g, α_o, α_w = densities of the gas, oil and water respectively ;
C_D = discharge coefficient of the venturi ;
$E = 1/(1 - \beta^4)$ = speed factor (β = d/D = Beta factor) ;
A_t = area of the venturi throat ;
ρ_{3m} = density of the mixture ;
Δp = differential pressure between inlet and throat of the venturi.

In the case of differential pressure measurement on a mixing element [5], the correlation with the velocity of the multiphase mixture (U) and the liquid fraction (ε_L) is employed through the following expression:

$$\Delta P = k\, U^2\, \varepsilon_L \qquad (8)$$

where k is a factor of the mixer resistance.

3 COMMERCIAL MULTIPHASE FLOW METER DESCRIPTION

The following variables are necessary to compute multiphase flow rates: the cross–section area of the pipe occupied by each phase, the axial velocity of each phase through each corresponding area, actual temperature and pressure. The product of the area phase fraction and velocities gives the volumetric flow rate, whereas pressure and temperature enable the calculation of phase densities through PVT properties. Due to the natural occurrence of variability in multiphase flow, different strategies have been adopted at developing multiphase meters.

3.1 Multiphase Meter Based on Separation

This type of meter consists of a micro-separator (*GLCC* type, cyclone, etc) to separate the liquid phase (oil + water) from the gaseous, with later measurements using conventional meters, the liquid line being provided with a *BS&W* monitor to determine the water fraction. In this case, gas flow metering is made by a device accepting the presence of carried liquid. Multiphase meters classified in this category include *Kvaerner/Phase Dynamics Compact Cyclone System* and *Wellcomp*.

3.2 Multiphase Meter with Partial Separation of the Gaseous Phase

Generally all the in-line meters present a poor performance in high gas fraction (case of wet gas/gas with condensate), so this type of meter is characterized by the separation of part of the free gas from the main flow. After this separation process, the gas and gas + liquid flows are submitted to individual in-line meters. The separated gas is measured by a meter accepting the presence of carried liquid. The remaining gas, together with the oil and water stream, pass through a set of instruments where oil, water and gas flows are determined. In this situation the partial separation of a large proportion of the gas phase allows more accurate metering of the remaining multiphase mixture. Meters under this category include the new version of *Agar* (SWTS).

3.3 In-Line Multiphase Meter

This type of meter is characterized by complete measurement of fraction and flow in each phase (gas, oil and water) carried out without any separation or sampling resources. Some meter concepts assume that two, or even the three phases flow at the same speed, consequently decreasing the required number of measurements. In this case, a mixer is installed upstream the meter.

Follow the description of the main multiphase flow meters (in alphabetical order), in accordance with the strategies adopted to measure the oil, water and gas fractions and flow rates.

- *Agar Corporation*

This meter combines a positive displacement device, a dual momentum meter (two venturis in series) in a vertically upward flow and a microwave monitor [5]. The total flow rate of gas and liquid is determined by the positive displacement. The momentum meter measures the flow rates of liquid and gas using the fundamentals of fluid flow through a venturi. The water cut is derived from the energy absorbed by the multiphase mixture from the microwave monitor.

- DUET (*Kvaerner Oilfield Products*)

This meter combines two gamma ray densitometers separated by a known distance along of the pipe and pressure and temperature sensors [6]. The first is a single energy gamma ray densitometer that measures the density of the mixture. The second is a dual energy gamma ray densitometer that measures mass fraction of oil and water in the liquid. The gas fraction is determined from the combined thickness of oil and water in the gamma ray beam. Velocity measurement is performed by cross-correlation of two gamma ray densitometer signals.

- ESMER (*Petroleum Software Limited*)

This concept is based on measuring the flow rates of individual phases in oil production lines using standard differential pressure, pressure, temperature and impedance (capacitance and conductance) sensors. The ESMER technology is founded on random signal analysis and pattern recognition in order to take a fingerprint of the signals and relate them to the flow rates of the individual phases [7]. A version using an extra orifice plate is also available.

- *Fluenta AS*

This meter uses several different sensors, arranged in combination [8]. A single gamma densitometer measures the average density of the mixture. Capacitance and inductive sensors are used to measure electrical properties of the mixture in oil and water continuous flow, respectively. The phase fractions can then be determined from this information. Velocity measurements are performed by cross-correlation of capacitance signals in case of oil continuous regime and by differential pressure across a venturi in case of water continuous regime.

- *Framo Engineering AS*

In this concept [9], at upstream of the measurement section there is a special static mixer. The measurement section is composed of a venturi and a dual-energy gamma ray densitometer. The dual-energy gamma densitometer is mounted at the throat of the venturi and is used to determine phase fractions. The velocity of the mixture is determined by the venturi.

- *MFI* (*Roxar Limited*)

This concept uses an electromagnetic resonant cavity and a single energy gamma ray densitometer [10]. The resonant frequency of the cavity is a function of the shape, geometry and dielectric constant of the multiphase mixture. The gamma ray densitometer is used to measure the total mixture density and the resonant cavity measures the dielectric constant of the medium. The phase fractions are determined by combining the dielectric constant and the total mixture density. The mixture velocity is determined by cross-correlation between two microwave sensors located at a known axial distance from each other.

- MIXMETER (*Jiskoot*)

This meter uses a static mixer with a dual-energy gamma densitometer [11]. The function of the mixer is to homogenize the mixture before it reaches the dual-energy gamma ray densitometer and to measure the mixture velocity by differential pressure measurement across the mixer. The phase fractions are determined by taking radiation attenuation measurements.

- VenturiX (*3-Phase Measurements AS*)

This meter combines a venturi device and a dual energy meter located at the venturi throat [12]. There are two versions available, one for periodic testing services and other for permanent monitoring.

4 PERFORMANCE OF MULTIPHASE METERS

Over the years, the technological evolution has been showing a clear advance in the performance of the multiphase meters. Such progress was achieved basically due to the JIP (Joint Industrial Projects) strategies, which allowed several technologies to be tested under different process conditions over the last ten years.

Petrobras participated in the following projects: (a) Performance Evaluation of the Neptunia and L4H Pumps and Multiphase Flow Meters, coordinated by Texaco which tested four multiphase meters: *Fluenta, Agar, Framo* and *MFI*; (b) Project Multiflow I and II coordinated by NEL, which tested the meters ESMER, Fluenta, MFI, Framo, DUET and Agar; (c) Mixmeter Project conducted by Imperial College; and (d) a JIP conducted with Fluenta which included the test of a meter installed in a manifold at Albacora field (Campos Basin, Brazil) at a water depth of 459 meters.

As the flow meter development progressed, the minimum achievable uncertainty went from approximately $\pm$ 20% in each phase down to $\pm$ 5-10% of reading and water cut at $\pm$ 2% absolute.

5 FUTURE SCENARIOS FOR MULTIPHASE METERING

Future scenarios for multiphase metering application include the wet christmas-tree and down-hole site. These scenarios will enable the entire production system to be simplified, including subsea manifolds and even elimination of some production components. As a consequence, the follow-up of the reservoir depletion, of the performance of each well, production shut-down and the optimization of production by gas-lift shall be effected in real time.

The future of multiphase metering is intrinsically associated with the reduction in selling prices, mainly in the case of the topside type meters, in addition to wider acceptance of the use of radioactive devices on the users' part, although there are currently some concepts of meters being developed, which do not employ this type of technology.

Even though the technological maturity stage has already started, there is still work to be done regarding standard modification in the operating culture, from the one based on test separator to well testing. Although several tests have already shown that the uncertainties of a multiphase meter are comparable, at the very least, to those of a typical test separator, users still assume that test separators work satisfactorily, even when they do not consider the defects of such equipment, as for instance the low separation efficiency (5 to 20% of efficiency loss). In short, the acceptance of multiphase meters will have to be based on a change in the culture of production system operation.

Nowadays multiphase meters have already been accepted for subsea applications and in those cases of unmanned systems, solely because such systems require a total automation level, associated with a reasonable degree of reliability. Some meters have the advantage of not including movable parts or devices which may suffer wear and tear (for example, control valves).

The natural path for multiphase meters is to be installed in wet christmas-trees and even on well bottom or down-hole environments. In these cases measurements shall be effected under conditions closer to the oil field reality, allowing on-line monitoring to be performed. Some companies projecting sub-sea systems have already concepts of meters on the trees, integrated to the controlling systems of the latter. Once each oil well is provided with its own multiphase meter, on-line management of the reservoir will become feasible, with immediate action on its production adjustment.

A possible concept of an on-line oil field management system is the one called “Optimizing Module of Field Flow” (MODFLOW™). According to this concept, each Christmas tree is smart and provided with a multiphase meter, gas-lift gas meter, oil/gas-lift chokes provided with remote adjustment devices, and integrated subsea control system, connected to the communications network (for example, using optical fiber). The communications network carries every information on the tree’s variables (for instance, oil, gas and water flows, pressure, temperature, gas-lift flow, etc.) and the set points for the correct positioning of the chokes of oil and gas lift. The same applies to water and gas injection wells of the same field. At the Offshore Production Unit, the communications network is integrated to the supervisory system (e.g. ECOS), where the Optimizing Module will have the following functions: a) Well Simulator; b) Reservoir Simulator; c) Control Module and Set Point Generator; and e) Efficiency Calculator (efficiency of each well, efficiency of the oil field, operating cost of oil per well and total operating cost of oil). In order to assess efficiency, the Optimizing Module must also receive the data concerning internal consumption of the plant (kWh, exportation figures, gas burning, injection, chemical products, etc.) and generate basic commands to the gas compressing systems, water injection pumps, oil exportation pumps, etc.

6 CONCLUSIONS

Commercial multiphase meters have reached uncertainties of $\pm$ 5-10% over a large operation range, which is considered a satisfactory performance, equal to or better than that of a test separator. However, their employment still depends on cost/benefit analyses, operating impact, legal and cultural implications due to the use of devices based on radioactive attenuation, lack of knowledge of the functioning and reliability of multiphase meters, doubts concerning the need of re-calibration, etc.

In the subsea environment, as in the case of subsea manifolds, wet christmas-trees and down-hole sites, the employment of multiphase metering has advanced, mainly on account of the urgent need for this kind of technology as a result of cost reduction, simplified facilities and reduction and/or elimination of the functions performed in the topside environment.

After two decades of development, the technological route of multiphase metering reached a better understanding of the behavior of different physical principles (capacitance, microwave, radioactive attenuation, etc.), conventional flow meters (venturi, positive displacement, mixer), signal processing and development of new correlations in multiphase flow, and this enabled several paradigms to be abandoned, which led to the development of more compact and lower cost meters.

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