

MULTIPHASE FLOW MEASUREMENT SYSTEM

BACKGROUND OF THE INVENTION

1. *Field of the Invention*

This invention relates to the field of flow metering technology including systems for use in measuring production volumes including a multiphase mixture of discrete phases, e.g., a mixture including oil, gas, and water phases. More specifically, this system utilizes a Coriolis flowmeter in combination with a two phase separator to measure production volumes of the respective components or phases of the multiphase mixture.

2. *Statement of the Problem*

It is often the case that a material flowing through a pipeline contains multiple phases. As used herein, the term "phase" refers to a type of material that may exist in contact with other materials. For example, a mixture of oil and water includes a discrete oil phase and a discrete water phase. Similarly, a mixture of oil, gas, and water includes a discrete gas phase and a discrete liquid phase with the liquid phase including an oil phase and a water phase. The term "material" is used herein in the context that material includes gas and liquids.

Special problems arise when one uses a flowmeter to measure volumetric or mass flow rates in a combined multiphase flow stream. Specifically, the flowmeter is designed to provide a direct measurement of the combined flow stream, but this measurement cannot be directly resolved into individual measurements of the respective phases. This problem is particularly acute in the petroleum industry where producing oil and gas wells provide a multiphase flow stream including unprocessed oil, gas, and saltwater.

It is a common practice in the petroleum industry to install equipment that is used to separate respective oil, gas, and water phases of flow from oil and gas wells. The producing wells in a field or a portion of a field often share a production facility for this purpose, including a main production separator, a well test separator, pipeline transportation access, saltwater disposal wells, and safety control features. Proper management of producing oil or gas fields demands knowledge of the respective volumes of oil, gas and water that are produced from the fields and individual wells in the fields. This knowledge is used to improve the producing efficiency of the field, as well as in allocating ownership of revenues from commercial sales of bulk production.

Early installations of separation equipment have included the installation of large and bulky vessel-type separation devices. These devices have a horizontal or vertical oblong pressure vessel together with internal valve and weir assemblies. Industry terminology refers to a 'two-phase' separator as one that is used to separate a gas phase from a liquid phase including oil and water. The use of a two phase separator does not permit direct volumetric measurements to be obtained from segregated oil and water components under actual producing conditions because the combined oil and water fractions are, in practice, not broken out from the combined liquid stream. A 'three-phase' separator is used to separate the gas phase from the liquid phases and also separates the liquid phase into an oil phase and water phase. As compared to two-phase separators, three-phase separators require additional valve and weir assemblies, and typically have larger volumes to permit longer residence times of produced materials for gravity separation of the production materials into their respective oil, gas, and water components.

Older pressure vessel separators are bulky and occupy a relatively large surface area. This surface area is very limited and quite expensive to provide in certain installations including offshore production platforms and subsea completion templates. Some development efforts have attempted to provide multiphase measurement capabilities in compact packages for use in locations where surface area is limited. These packages typically require the use of nuclear technology to obtain multiphase flow measurements.

Coriolis flowmeters are mass flowmeters that can also be operated as vibrating tube densitometers. The density of each phase may be used to convert the mass flow rate for a particular phase into a volumetric measurement. Numerous difficulties exist in using a Coriolis flowmeter to identify the respective mass percentages of oil, gas, and water in a total combined flow stream.

United States Patent No. 5,029,482 teaches the use of empirically-derived correlations that are obtained by flowing combined gas and liquid flow streams having known mass percentages of the respective gas and liquid components through a Coriolis meter. The empirically-derived correlations are then used to calculate the percentage of gas and the percentage of liquid in a combined gas and liquid flow stream of unknown gas and liquid percentages based upon a direct Coriolis measurement of the total mass flow rate. The composition of the fluid mixture from

the well can change with time based upon pressure, volume, and temperature phenomena as pressure in the reservoir depletes and, consequently, there is a continuing need to reverify the density value.

5 United States Patent No. 4,773,257 teaches that a water fraction of a total oil and water flow stream may be calculated by adjusting the measured total mass flow rate for water content, and that the corresponding mass flow rates of the respective oil and water phases may be converted into volumetric values by dividing the mass flow rate for the respective phases by the density of the respective phases. The density of the respective phases must be determined from actual laboratory
10 measurements. The '257 patent relies upon separation equipment to accomplish separation of gas from the total liquids, and this separation is assumed to be complete.

United States Patent No. 5,654,502 describes a self-calibrating Coriolis flowmeter that uses a separator to obtain respective oil and water density
15 measurements, as opposed to laboratory density measurements. Oil density measurements are corrected for water content, which is measured by a water cut monitor or probe. The '502 patent relies upon a separator to eliminate gas from the fluids traveling through the meter, and does not teach a mechanism for providing multiphase flow measurements when gas is a part of the flow stream that is applied
20 to the Coriolis flowmeter.

Even three phase separation equipment does not necessarily provide complete separation of the oil phase from the water phase. Water cut probes are used to measure water content in the segregated oil phase because a residual water content of up to about ten percent typically remains in the visibly segregated oil component.
25 The term 'water cut' is used to describe the water content of a multiphase mixture, and is most often applied to a ratio that represents a relationship between a volume of oil and a volume of water in an oil and water mixture. According to the most conventional usage of the term 'water cut', well production fluids would have a 95% water cut when water comprises 95 out of a total 100 barrels of oil and water liquids. The term 'water
30 cut' is sometimes also used to indicate a ratio of the total volume of oil produced to the total volume of water produced. A term 'oil cut' could imply the oil volume divided by the combined oil and water volume. As defined herein, the term 'water cut'

encompasses any value that is mathematically equivalent to a value representing water or oil as a percentage of a total liquid mixture including water and oil.

There remains a need to provide a compact package for performing multiphase flow measurements when gas is part of the flow stream and where the package does not require the use of nuclear technology to perform direct measurements on the fluid. Accordingly, it is an aspect of the present invention to provide method and apparatus that is capable of performing multiphase flow measurements in systems having mixtures of gas and liquids or in liquid systems having mixtures of liquids, whether these mixtures are miscible or immiscible..

SOLUTION

The present invention overcomes the problems that are outlined above by providing a fully automated Coriolis-based well test system which does not require manual sampling or laboratory analysis of the production material in order to determine the density of the phase components. Additionally, the test system eliminates volumetric measurement errors that derive from the liberation of solution gas at reduced pressures.

A well test system in accordance with this invention has two modes of operation. The test system operates as a normal well test system to measure the volume of respective components that are separated from a component mixture, namely, a wellhead production material including oil, gas, and water phases. The well test system also has a special density determination mode that avoids the need to obtain hand samples of the production fluids for density measurements. On site density measurements obtained from the well test system are more accurate than laboratory measurements because the material is measured at line conditions.

The well test system also includes devices that separate a combined flowstream including multiphase wellhead production fluids into separate components. A valve manifold is used to selectively fill a vortex separator with the production from a single well. A gravity separator is used to retain a mixture of oil, gas, and water phases from multiple wells while the forces of gravity segregate these components from the production mixture. A dump valve is opened to at least partially drain the liquid components of the production component mixture from the gravity separator after separation of the respective components.

Coriolis flowmeters may be operated in a mass flowmeter mode and densitometer mode. These meters are used to measure the mass flow rates of the respective oil and water components as they leave the respective separators. Density measurements are obtained from the segregated oil components of multiphase flow. A water cut monitor is used to obtain water cut readings of the segregated oil phase. Altogether, fluid density, temperature, mass flow rate, and water cut measurements are used to calculate a volumetric flow rate for the oil and water phases in the production stream. This correction results in a more accurate calculation for the volumetric oil flow rate.

In preferred embodiments, volumetric test errors are also minimized by connecting a pressurized gas source to the test separator. The pressurized gas source is used to maintain a substantially constant separator pressure even when the separator dump valve is permitting flow of liquids from within the test separator.

Other salient features, objects, and advantages will be apparent to those skilled in the art upon a reading of the discussion below in combination with the accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG.1 depicts a schematic layout of an automated well test system according to the present invention;

FIG. 2 depicts a flow chart diagram governing the operation of the FIG. 1 system;

FIG. 3 is a plot of hypothetical data demonstrating the practical effects of gas damping on the frequency response of flowtubes in a Coriolis flowmeter; and

FIG. 4 is a plot of hypothetical data showing the relationship between drive gain and time for an event where a transient bubble enters a Coriolis flowmeter.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

FIG. 1 depicts a schematic diagram of a compact multiphase flow measurement system 100 for use in the petroleum industry. System 100 includes an incoming multiphase flow line 102 that discharges into a vertical two phase vortex separator 104. In turn, the vortex separator 104 discharges gas into an upper gas measurement flow line 106 and discharges liquids into a lower liquid measurement flow line 108. The gas measurement flow line 106 and the liquid measurement flow line 108 recombine into discharge line 110 after flow measurements have been

performed. A controller 112 includes a central processor together with associated circuitry for operating the respective components of system 100. The system 100 is mounted on skid structure 114 for portability, and a production manifold 116 supplies multiphase fluids to system 100 from a plurality of oil or gas wells. Discharge flow line 110 leads to a three phase production separator 118 for separation of gas, water and oil phases prior to a point of commercial sale.

The incoming multiphase flow line 102 receives multiphase fluids including oil, gas, and water from production manifold 116 along the direction of arrow 120. A venturi section 122 utilizes the well known Bernouli effect to reduce pressure in the incoming multiphase fluids within flow line 102 at the throat of the venturi. It is preferred that the degree of pressure reduction occurs to a level which approximates the internal working pressure within the liquid Coriolis meter 166. This reduction in pressure liberates or flashes gas from the multiphase fluids within flow line 102. An incline/decline section 124 facilitates gravity segregation in the gas and liquid phases of the multiphase fluids preceding the vortex separator 104. A horizontal discharge element 126 feeds the vortex separator 104.

Vortex separator 104 is depicted in midsectional view to reveal interior working components. Horizontal discharge element 126 is operably positioned for tangential discharge into the cylindrical interior separation section of vortex separator 104. This manner of discharge causes a tornado or cyclone effect to occur in a liquid portion 128 of multiphase fluids within vortex separator 104.

The liquid portion 128 is a majority liquid phase including discrete water, oil, and entrained gas phases. Centrifugal forces arising from the cyclone effect cause additional separation of the entrained gas phase from the liquid portion 128, but it is not possible to completely eliminate the entrained gas phase except at relatively low flow rates permitting additional gravity segregation of the entrained gas phase. The liquid portion 128 discharges from vortex separator 104 into the liquid measurement flow line 108. A water trap 130 is installed in the lower portion of vortex separator 104. This trap may be bled to obtain periodic water density measurements, or a water density meter (not depicted in FIG. 1) may be installed in combination with the trap 130 to provide water density information to controller 112.

A gas portion 132 of the multiphase fluids within vortex separator is a majority gas phase including gas together with mists of oil and water. A mist collecting screen

134 is used for partial condensation of the mists, which in condensed form drip back into the liquid portion 128

Gas portion 132 discharges into the gas measurement flow line 106. Gas measurement flow line 106 includes a pressure transmitter 135 that transmits an absolute pressure reading of pressure within gas measurement flow line 106 to controller 112 with path 136. Pressure transmitter 135 may be purchased commercially, for example, as a Model 2088 pressure transmitter from Rosemount of Eden Prairie, Minnesota. A tube 138 connects gas measurement line 136 with the bottom of vortex separator 104. Tube 138 contains a hydrostatic gauge 140 coupled with a pressure transmitter 142 for use in transmitting pressure information concerning the hydrostatic head between point 144 within gas measurement flow line 106 and point 146 at the bottom of vortex separator 104. Path 148 connects the pressure transmitter 142 with controller 112, which uses the hydrostatic head data from pressure transmitter 142 to open and close electrically operable throttling valves 150 and 174 for pressure adjustment assuring proper operation of vortex separator 104, i.e., to prevent vortex separator from becoming overfull with gas to the point where gas portion 132 discharges into liquid measurement flow line 108 or to the point where liquid portion 128 discharges into gas measurement flow line 106. Paths 152 and 176 operably connect controller 112 with the throttling valves 150 and 174, which may, for example, be purchased as Model V2001066-ASCO valves from Fisher of Marshall Town, Iowa.

A Coriolis mass flowmeter 154 in gas measurement flow line 106 provides mass flow rate and density measurements from gas portion 132 of a multiphase fluid within gas measurement flow line 106. The Coriolis mass flowmeter 154 is coupled with a flow transmitter 156 for providing signals representing these measurements to Controller 112. Coriolis flowmeter 154 is electronically configured for operations including measurements of mass flow rates, densities, and temperatures of materials passing through gas measurement flow line 106. Exemplary forms of Coriolis flowmeter 154 include the ELITE Models CMF300356NU and Model CMF300H551NU, which are available from Micro Motion of Boulder, Colorado.

Path 158 operably couples flow transmitter 156 with controller 112 for transmission of these signals. A check valve 160 in gas measurement flow line 106



assures positive flow in the direction of arrow 162, thus preventing intrusion of liquid portion 128 into gas measurement flow line 106.

Liquid measurement flow line 108 contains a static mixer 164, which turbulates the liquid portion 128 within liquid measurement flow line 108 to prevent gravity segregation of the respective oil, water, and entrained gas phases. A Coriolis flowmeter 166 provides mass flow rate and density measurements of liquid portion 128 within liquid measurement flow line 108, and is connected to flow transmitter 168 for transmission of signals representing these measurements via path 170 to controller 112.

A water cut monitor 172 is installed in liquid measurement flow line 108 to measure the water cut in liquid portion 128 within liquid measurement flow line 108. The type of water cut monitor is selected depending upon how large the water cut is expected to be in the flow stream. For example, capacitance meters are relatively inexpensive, but other types of meters may be required where the water cut may exceed about 30% by volume. Capacitance or resistance probes operate on the principle that oil and water have drastically different dielectric constants. These probes lose sensitivity with increasing water content, and provide acceptably accurate water cut measurements only where the water volume is less than about 20% to 30% of the total flow stream. The upper 30% accuracy limit is far below the level that is observed from many producing wells. For example, the total liquid production volume of an oil well can be 99% water. Capacitance or resistivity based water cut monitors, therefore, are relegated to determining the water cut in an oil component that has a relatively low water content.

Commercially available devices that are used to measure water cut include near infrared sensors, capacitance/inductance sensors, microwave sensors, and radio frequency sensors. Each type of device is associated with operational limits. Thus, a water cut probe can measure the volumetric percentage of water in a combined oil and water flow stream.

Water cut monitoring devices including microwave devices are capable of detecting water in amount up to about one hundred percent of the flow mixture, but in environments including three phase flow are subject to interpreting gas content as oil. This interpretation occurs because microwave detection devices operate on the principle that water in the spectrum of interest absorbs sixty times more microwave

energy than does crude oil. The absorption calculations assume is that no natural gas is present, but natural gas absorbs twice as much microwave radiation than does crude oil. It follows that a microwave water cut detection system could correct the water cut reading by compensating for the fact that gas in the mixture has affected the measurement.

Path 173 operably connects water cut monitor 172 with controller 112. Controller 112 uses an electrically actuated two way valve 174 to control pressure in liquid measurement line 108 in a manner that assures proper operation of vortex separator 104 in cooperation with valve 150, i.e., valve 174 is opened and closed to prevent gas portion 132 from discharging into liquid measurement flow line 108 and to prevent liquid portion 128 from discharging into gas measurement flow line 106. Path 176 operably connects valve 174 with controller 112. A check valve 178 in liquid measurement flow line 108 assures positive flow in the direction of arrow 180, thus preventing intrusion of gas portion 132 into the liquid measurement flow line 108. The gas measurement flow line 106 meets in a T with liquid measurement flow line 108 to form a common discharge flow line 110 leading to production separator 118.

Controller 112 is an automation system that is used to govern the operation of system 100. On a basic level, controller 112 includes a computer 84 that is programmed with data acquisition and programming software together with driver circuitry and interfaces for operation of remote devices. A preferred form of controller 112 is the Fisher Model ROC364.

The production manifold 116 contains a plurality of electronically operable three way valves, e.g., valves 182 and 184, which each have corresponding production sources such as an oil well 186 or a gas well 188. A particularly preferred three way valve for use in this application is the Xomox TUFFLINE 037AX WCB/316 well switching valve with a MATRYX MX200 actuator. The valves are preferably configured to each receive production fluids from a corresponding individual well, but may also receive production from a group of wells. Controller 112 selectively configures these valves by transmitting signals over path 190. The valves are selectively configured to flow multiphase fluids from a well 186 or combinations of wells (e.g. wells 186 and 188) into rail 192 for delivery of fluids into incoming multiphase flow line 102 while other valves are selectively configured to bypass system 100 by flowing through bypass flow line 194.



Production separator 118 is connected to pressure transmitter 195 and path 196 for transmission of signals to controller 112. Separator 118 is operably connected with a gas sales line, an oil sales line, and a salt water discharge line (not depicted in FIG. 1) in any conventional manner known to those skilled in the art.

5 Operation of System 100

FIG. 2 depicts a schematic process diagram of a process P200 representing control logic for use in programming controller 112. These instructions typically reside in an electronic memory or an electronic storage device for access and use by controller 112. Instructions that embody the process P200 can be stored on any machine readable medium for retrieval, interpretation and execution by controller 112 or similar devices that are connected to system 100 in any operable manner.

Process P200 begins with step P202 in which controller 112 determines that it is proper to enter a production test mode. With regard to FIG. 1, this means that controller 112 selectively configures the valves 182 and 184 of production manifold 116 to flow a well or an operator-selected combinations of wells corresponding to production sources 186 and 188 through rail 192 and into incoming multiphase flow line 102. This determination is usually performed on the basis of a time delay, e.g., to test each well at least once per week. The test mode may also be performed on a continuous basis with the respective valves of production manifold 116 always being selectively configured to flow into system 100 while other valves are configured to bypass system 100 through bypass line 194. These types of well test measurements are conventionally used in allocating, on a deliverability basis, the percentages of the total flow stream that pass through production separator 118 to specific production sources, e.g., sources 186 and 188.

25 Manually actuated valves 196 and 197 can be opened and closed for selective
isolation of system 100, i.e., valves 196 and 197 can both be closed for the removal
of all components that are mounted on skid 114. An electrically actuated valve 199
is normally closed. A second or redundant bypass line 198 interior to valves 196 and
197 permits flow to bypass system 100 when valve 199 is open and valves 150 and
30 174 are closed.

Testing begins in step P204 with controller 112 constricting or opening valves 150 and 174 to reduce or increase the total flow rate through vortex separator 104 for the purpose of separating gas from liquid phases in the multiphase fluid. The total



flow rate through system 100 need not be reduced because controller 112 can open valve 199 to permit flow through interior bypass 198. The exact flow rate depends upon the physical volume of the vortex separator and liquid measurement flow line 108, as well as the amount of fluid that sources 186 and 188 are capable of delivering to system 100.

The object of reducing the flow rate through system 100 is to eliminate entrained bubbles from liquid measurement flow line 108 through the use of vortex separator 104 with assistance by gravity segregation while the flow rate is still high enough to prevent substantial gravity segregation of oil from water in the remaining liquid phase. It is also possible to accomplish substantially complete separation of the gas phase from the liquid phase by increasing the flow rate with separation being accomplished by centrifugal forces through vortex separator 104. Controller 112 monitors the drive gain or pickoff voltage from Coriolis flowmeter 166 for this purpose, as explained with reference to FIGS. 3 and 4.

FIG. 3 is a plot of hypothetical data demonstrating the practical effects of gas damping on the frequency response of flowtubes in the Coriolis flowmeter 166 (see also FIG. 1). The log of transmissivity is plotted as a function of the frequency of alternating voltage applied to the drive coil of Coriolis flowmeter 166, e.g., at frequencies f_0 , f_1 , and f_2 . The transmissivity ratio T_r equals the output of meter pickoff coils divided by the drive input, i.e., T_r is the drive gain:

$$(1) \quad T_r = \frac{OUTPUT}{INPUT} = \frac{V_{ac} PICKOFF COIL}{V_{ac} DRIVE COIL}$$

A first curve 300 corresponds to the undamped system of Equation (1), i.e., no gas is present in the fluid being measured. A second curve 302 corresponds to a damped system where gas is present. Both curves 300 and 302 have an optimal value 304 and 304', respectively, at the natural frequency f_n .

FIG. 4 is a plot of hypothetical data showing the relationship between drive gain and time for an event 400 where a transient bubble enters the Coriolis flowmeter 166 as a bubble entrained in a multiphase fluid. The bubble enters at time 402 and exits at time 404. Drive gain is expressed as a percentage in FIG. 4, and plotted as a function of time at intervals, e.g., t_1 , t_2 , and t_3 . Controller 112 (see also FIG. 1) is programmed to monitor drive gain or transmissivity by comparing the same against

a threshold value 406. Where the drive gain or transmissivity of curve 408 exceeds threshold 406, controller 112 recognizes that density measurements are affected by the presence of transient bubbles. Thus, Coriolis flowmeter 166 uses only density values obtained when drive gain is less than threshold 406 for purposes of step P206.

- 5 The exact level of threshold 406 depends upon the specific meter design together with the intended environment of use, and is intended to permit less than one to two percent gas by volume in the multiphase fluid.

10 In operating Coriolis meters, it is often the case that the pickoff voltage drops in inverse proportion to the event 400 of the curve 400 shown in FIG. 4. The meters are sometimes programmed to sense this drop in amplitude, and they respond by vibrating an oscillation coil to an amplitude of maximum design specification until the gas damping effect is reversed.

15 With controller 112 opening and/or closing valves 150 and 174 until the drive gain falls below threshold 406 in the manner described for step P204, step P206 includes Coriolis flowmeter 166 measuring density of the liquid phase without entrained gas. This density measurement is intended to represent density of the liquid phase having no gas voids. This density measurement is referred to as ρ_L in the discussion below, and is used to describe the density of a liquid mixture including gas and oil with no entrained gas fraction. As an alternative to performing direct
20 measurements on the multiphase fluid in liquid measurement line 108, it is also possible to obtain samples of the multiphase fluid for laboratory analysis or to approximate density measurements by the use of empirically derived fluid correlations to obtain less preferred approximations of ρ_L .

25 In step P208, controller 112 selectively adjusts valves 150 and 174 in a manner that optimizes separation results in vortex separator 104 according to manufacturer's specifications based upon the gross rates of flow through Coriolis flowmeters 154 and 166 together with pressure signals received from pressure transmitter 135 and differential pressure gauge 140. In this step, production manifold 116 is configured to flow for active producing well test measurements. Vortex separator 104 functions
30 differently in this step, as compared to step P204, because controller 112 does not adjust valves 150 and 174 in a manner that reduces drive gain below the threshold 406 shown in FIG. 4. In this circumstance, the majority liquid phase flowing through liquid measurement line 108 may include entrained gas bubbles.



Step P210 includes the use of Coriolis flowmeter 166 to measure the total mass flow rate Q_{TL} of the majority liquid phase including entrained gas within liquid measurement line 108, as well as the density of the majority liquid phase. This density measurement is referred to as ρ_{meas} in the discussion that follows.

5 In step P212, controller 112 determines the dry gas density ρ_{gas} of the gas in the multiphase fluid. Gas density may be calculated from pressure and temperature information using well known correlations developed by the American Gas Association based upon gas gravity, or laboratory analysis may provide other empirical correlations for gas density determined from actual measurements of produced gas
10 from the multiphase flow stream. Another alternative technique for the determination of gas density is to obtain an actual density measurement from Coriolis flowmeter 154 simultaneously with step P204 or in a separate step P210 where controller 112 selectively adjusts valves 150 and 174 to minimize the drive gain intensity shown in FIG. 4. In some situations, it is also possible to assume that the gas density remains
15 constant because the density of gas is relatively low in comparison to the liquid density, and the assumption of a constant gas density may result in an acceptable level of error.

In step P214, controller 112 calculates a gas void fraction X_L in the liquid phase where

$$20 \quad (2) \quad X_L = \frac{\rho_{calc} - \rho_{meas}}{\rho_{calc}},$$

where X_L is the void fraction representing gas void in the multiphase fluid flowing through Coriolis flowmeter 166, i denotes successive iterations, ρ_{meas} is the density measurement obtained in step P210 as described above, and ρ_{calc} is a calculated or estimated density value approximating the density of a multiphase liquid having a void
25 fraction of about X_L . Equation (2) will be used in an iterative convergence algorithm. Thus, it is acceptable to begin calculations with a first guess, e.g., a stored value for ρ_{calc} from the preceding cycle of test measurements for a particular production source 186 or an arbitrary value such as 0.8 g/cc.

A particularly preferred manner of providing a first guess for the value of ρ_{calc}
30 is to obtain a water cut measurement from water cut monitor 172. Then it is possible

to assume that no gas is present in the multiphase flow mixture and solve Equation (3) for ρ_{calc} :

$$(3) \quad \rho_{alc} = WC(\rho_w - \rho_o) + \rho_o$$

where WC is water cut expressed as a fraction comprising the amount of water in the liquid mixture divided by the total volume of the liquid mixture, ρ_w is the density of water in the liquid mixture, and ρ_o is the density of oil in the liquid mixture. The resultant first guess for ρ_{calc} is the theoretical value of a liquid mixture having no gas void fraction. The measured density ρ_{meas} will be less than ρ_{calc} when X_i is greater than zero, provided the values ρ_w and ρ_o are correct. The values ρ_w and ρ_o may be obtained from laboratory measurements that are performed on samples of the majority liquid phase including respective oil and water phases. For example, a water density value may be obtained from a hydrometer connected to water trap 130. These values may also be approximated to acceptable levels of accuracy by well known empirical correlations that are published by the American Petroleum Institute.

In step P216, controller 112 performs a calculation to determine whether the last guess for ρ_{calc} has provided a calculation of X_{Li} according to Equation (2) wherein the value of X_i has converged within an acceptable range of error. The next guess for ρ_{calc} is calculated as:

$$(4) \rho_{calci} = (\rho_{gas}X_{Li}) + (1 - X_{Li})\rho_L$$

where ρ_{calci} is the next guess for ρ_{calc} calculated using the value X_{Li} from Equation (2), ρ_L is the density of the liquid mixture, and the remaining variables are defined above.

Step P218 is a test for convergence wherein convergence exists if the expression:

$$(5) D < | \rho_{calci} - \rho_{calc} |$$

is true where D is the absolute value of a delimiter representing a negligible error, e.g., 0.01 g/cc, or approximating the limits of precision that is available from Coriolis flowmeter 166, ρ_{calci} is the present value calculated according to Equation (4), and $\rho_{calci-1}$ is the old value of ρ_{calci} from the prior iteration of Equation (2) that produced the X_{Li} value corresponding to ρ_{calci} .

Where controller 112 in step P218 determines that there is no convergence, the new guess value ρ_{calci} is substituted for the old guess value ρ_{calc} in step P220, and steps P214 through P218 are repeated until convergence exists.

Water cut may be calculated as:

$$(6) \quad WC = \frac{\rho_L - \rho_o}{\rho_w - \rho_o}$$

wherein WC is water cut, ρ_o is a density of oil in the majority liquid component, and ρ_w is a density of water in said majority liquid component. Thus, water cut meter 172 is somewhat redundant if there is no gas phase in the multiphase flow, and may then be optionally eliminated because it is not a required value for this iterative convergence technique.

In step P214A, a more rigorous or noniterative solution is available, provided that the measured water cut value supplied by water cut meter 172 is within a range where the meter functions with acceptable accuracy and precision. The meter reading is a function of the fluid content, and this permits the simultaneous solution of a system of three equations to provide answers for three variables where the equations are:

$$(7) \quad \rho_w q_w + \rho_o q_o + \rho_g q_g = \rho_{mix},$$

$$(8) \quad f(sat) = M$$

$$(9) \quad q_w + q_o + q_g = 1$$

where ρ_w is the density of water in the flow stream, ρ_o is the density of oil in the flow stream, ρ_g is the density of gas in the flow stream, ρ_{mix} is the density of the combined flow stream, q_w is the fractional flow rate of water by volume (i.e., a water cut), q_o is the fractional flow rate of oil by volume, q_g is the fractional flow rate of gas by volume, and $f(sat)$ is a function of flow stream content that is unique to a particular type of water cut meter providing a total meter reading M.

Where the water cut meter is a microwave meter, the function $f(sat) = M$ may be approximated as:

$$(10) \quad m_w q_w + m_o q_o + m_g q_g = M,$$

where m_w is the meter reading in pure water, m_o is the meter reading in pure oil, m_g is the meter reading in pure gas, and the remaining terms are described above. Where, in a typical meter, $m_w = 60$, $m_o = 1$, and $m_g = 2$, Equations (8) through (11) can be solved for q_w as:

$$(11) \quad q_w = \frac{(\rho_{mix} - \rho_o) - (M - 1)(\rho_g - \rho_o)}{(\rho_w - \rho_o) - 59(\rho_g - \rho_o)}$$

where the terms are defined above. Also,

$$(12) \quad q_g = M - 1 - 59q_w, \text{ and}$$

$$(13) \quad q_o = 58q_w - M + 2.$$

- 5 Once convergence is achieved in step P218, step P222 entails using Coriolis flowmeter 154 to measure the mass flow rate Q_{TG} and density ρ_{mgas} of the majority gas phase flowing through Coriolis flowmeter 154 under the flow conditions of step P208.

- 10 Step P224 includes solving for the gas void fraction X_G in the majority gas phase flowing through gas measurement line 106, according to the equation:

$$(14) \quad XG = \frac{P_{mgas} - PL}{P_{gas} - PL}$$

where XG is a fraction corresponding to a volume of gas taken with respect to the total volume of the majority gas phase, ρ_{mgas} is a value obtained in step P222, ρ_{gas} is a value obtained in step P212, and ρ_L is a value obtained in step P206.

- 15 In step P224, the value of water cut obtained from water cut monitor 172 is adjusted, as needed, to compensate for the presence of gas in the majority liquid phase. For example, where the gas void fraction X_L is known, it is possible to use this value to correct water cut readings for microwave absorption based upon the assumption that only oil and water are present.

- 20 Step P226 includes using the data thus acquired to solve for the flow rates of the three respective phases in each of the majority liquid phase and the majority gas phase. These equations are useful for this purpose:

$$(15) \quad Q_L = Q_{TL} * (1 - X_i) + Q_{TG} * (1 - X_G);$$

$$(16) \quad Q_G = Q_{TL} * X_i + Q_{TG} * X_G;$$

25 (17) $Q_o = Q_L * (1 - WC);$

$$(18) \quad Q_w = Q_L * WC;$$

$$(19) \quad V_L = \frac{Q_L}{\rho_L};$$



$$(20) \quad V_O = \frac{Q_O}{\rho_O};$$

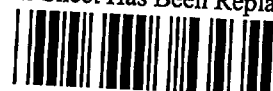
$$(21) \quad V_G = \frac{Q_G}{P_{gas}}; \text{ and}$$

$$(22) \quad V_W = \frac{Q_W}{P_W},$$

wherein Q_L is the total mass flow rate of the liquid phases flowing through system 100;
 5 X_i is the gas void fraction in the majority liquid phase determined from step P214 and
 resulting in convergence in step P218; Q_{TG} is the total gas mass flow rate of the
 majority gas phase measured in step P222; X_G is the gas void fraction in the majority
 gas phase determined in step P224; Q_G is the total gas mass flow rate through system
 100; Q_O is the total oil mass flow rate through system 100; Q_W is the total water mass
 10 flow rate through system 100; Q_O is the total oil mass flow rate through system 100;
 WC is the water cut provided from water cut monitor 172 with corrections as needed
 in step P224; V_L is the total volumetric flow rate of the liquid phases flowing through
 system 100; ρ_L is the liquid phase density determined in step P206; V_O is the total oil
 volumetric flow rate through system 100; ρ_o is oil density at flow conditions; V_G is the
 15 total gas volumetric flow rate through system 100; ρ_{gas} is gas density at flow
 conditions; V_w is the total water volumetric flow rate through system 100; and ρ_w is
 water density at flow conditions.

Controller 112 in step P228 provides system outputs including direct
 temperature, density, and mass flow rate measurements together with calculation
 20 results for volumetric and mass flow rates for the respective phases. These flow rates
 may be integrated over time to provide cumulative production volumes for the test
 interval.

Controller 112 in step P230 interacts with system components including
 production manifold 116 to optimize field efficiency. For example, in an oilfield having
 25 drive energy that is predominated by a gas cap, production efficiency is optimized
 when the gas cap is depleted after the oil is recovered. It is desirable to produce oil
 referentially before the gas, and the gas-oil contact may move downward into the
 former oil zone as the oil is depleted. This movement of the gas-oil contact can result



in wells that formerly produced primarily oil changing to produce primarily gas. The proper response to this drastically increased gas production in an oil well is normally to shut the well in or reduce its production rate so as not to deplete the drive energy of the reservoir, and controller 112 can be programmed to take this action. Similar
5 responses can be programmed for moving oil-water contacts or even to optimize present economic performance from an accounting standpoint by producing one low cost well before higher cost wells if all other factors are equal.

Those skilled in the art understand that the preferred embodiments described hereinabove may be subjected to apparent modifications without departing from the
10 scope and spirit of the invention. Accordingly, the inventors hereby state their full intention to rely upon the Doctrine of Equivalents in order to protect their full rights in the invention.

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CLAIMS:

1. A multiphase flow measurement system (100) for use in flow environments including a plurality of liquid phases and a gas phase that includes a separator (104) that separates an incoming multiphase flow into a majority liquid phase having a majority liquid content including entrained gas and a majority gas phase having a majority gas content and a flowmeter (166) that measures a flow rate of said majority liquid phase, wherein said system includes:
- 5 a controller (112) that is configured to measure a flow rate of said majority liquid phase using a calculation to quantify flowrates of a discrete liquid phase and a discrete gas phase in said majority liquid phase.
2. The multiphase flow measurement system (100) of claim 1 wherein said flowmeter (166) includes a mass flowmeter.
3. The multiphase flow measurement system (100) of claim 2 wherein said mass flowmeter (166) is a Coriolis mass flowmeter.
4. The multiphase flow measurement system (100) of claim 1 wherein said calculation of said flow rate of said majority liquid phase is free of empirically derived correlations excepting empirically derived correlations used to determine fluid properties selected from the group consisting of density and viscosity.
5. The multiphase flow measurement system (100) of claim 4 further comprising:
- a liquid measurement flow line (108) that flows a first liquid from said separator (104) in a manner providing essentially no entrained gas bubbles in said first liquid;
- 5 and
- a densimeter (166) that determines a density ρ_L of said first liquid in said liquid measurement line (108).
6. The multiphase flow measurement system (100) of claim 5 further comprising:

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a second densimeter that measures a density ρ_{meas} in said majority liquid phase; and

- 5 said controller (112) being further configured to calculate a void fraction X_L based upon a relationship between said density ρ_{meas} and said density ρ_L and to apply said void fraction X_L to a total flow rate Q_{TL} of said major liquid component to provide respective flow rates Q_L and Q_G , respectively, corresponding to liquid and gas components of said majority liquid phase.

7. The multiphase flow measurement system (100) of claim 6 wherein said controller (112) is further configured to calculate said void fraction X_L using an iterative convergence calculation.

8. The multiphase flow measurement system (100) of claim 7 wherein said controller (112) is further configured to converge said iterative convergence calculation based upon a difference between a measured density value and a theoretical density value based on said void fraction X_L .

9. The multiphase flow measurement system (100) of claim 8 wherein said transmitter (112) is further configured to calculate a void fraction X_L using a noniterative calculation.

10. The multiphase flow measurement system (100) of claim 9 wherein said transmitter (112) is further configured to calculate said void fraction X_L includes by comparing results from said iterative calculation against results from said noniterative calculation.

11. The multiphase flow measurement system (100) of claim 6 further comprising:

a gas densimeter (154) a gas density ρ_{gas} at temperature and pressure in said multiphase flow measurement system; and

- 5 said transmitter (112) being further configured to calculate a density ρ_{calc} based upon said gas density ρ_{gas} and said liquid density ρ_L and said void fraction X_L .

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12. The multiphase flow measurement system (100) of claim 11 wherein said transmitter (112) is further configured to calculate said density ρ_{calc} according to a relationship of said density ρ_{calc} being equal to said gas density ρ_{gas} multiplied by said void fraction X_L added to one minus said void fraction X_L multiplied by said liquid density ρ_L .

13. The multiphase flow measurement system of claim 12 wherein said transmitter (112) is configured to determine said flow rate of said majority liquid phase using an iterative calculation by iterating values of ρ_{calc} through successive values of X_L until ρ_{calc} converges within an acceptable range of error with respect to a value ρ_{meas} which is determined by said means for measuring a density ρ_{meas} .

14. The multiphase flow measurement system (100) of claim 13 wherein said transmitter (112) is configured to iterate values of said density ρ_{calc} according to a relationship that a gas void fraction X_L equals said density ρ_{calc} minus said density ρ_{meas} divided by said density ρ_{calc} wherein X_L is the gas void fraction based upon an iterative approximation of ρ_{calc} .

15. The multiphase flow measurement system (100) of claim 11 further comprising:

a water cut monitor (172) that measures a water cut WC in said majority liquid phase based upon said density ρ_{calc} when said majority liquid phase contains an oil phase and a water phase in an intended environment of use.

16. The multiphase flow measurement system (100) of claim 15 wherein said water cut monitor (172) operates according to a relationship that said water cut WC equals said density ρ_{calc} minus an oil density divided by a water density - said oil density wherein said oil density is a density of oil in said majority liquid phase, and said water density is a density of water in said majority liquid phase.

17. The multiphase flow measurement system (100) of claim 1 further comprising:

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a densimeter (154) that measures a density ρ_{mgas} of a majority gas component delivered from said separator;

5 a gas flowmeter (154) that measures a flow rate of said majority gas component.

18. The multiphase flow measurement system (100) of claim 17 wherein said transmitter is further configured to calculate a void fraction X_G of said majority gas phase based upon a density using said density ρ_{mgas} .

19. A method (P200) of performing multiphase flow measurements in flow environments including a liquid phase and a gas phase, said method comprising the steps of:

5 separating (P204) an incoming multiphase flow into a majority liquid phase having a majority liquid content with entrained gas and a majority gas phase having a majority gas content;

measuring (P210) a flow rate of said majority liquid phase; and

calculating (P226) to quantify flowrates of a discrete liquid phase and a discrete gas phase in said majority liquid phase.

20. The method (P200) of claim 19 wherein said step of calculating is free of empirically derived correlations excepting empirically derived correlations used to determine fluid properties selected from the group consisting of density, viscosity, and no empirically derived correlations.

21. The method (P200) of claim 20 wherein said step of measuring said flowrate of said majority liquid phase comprises the step of:

flowing a first liquid from said separating means in a manner providing essentially no entrained gas bubbles in said first majority liquid; and

5 measuring (P206) a density ρ_L of said first liquid.

22. The method (P200) of claim 21 wherein said step of measuring said flow rate of said majority liquid phase further comprising the step of:



- measuring (P210) a density ρ_{meas} in said majority liquid phase under conditions of normal flow possibly including entrained gas bubbles in said liquid phase; and
- 5 calculating (P214) a void fraction X_L based upon a relationship between said density ρ_{meas} determined and said density ρ_L ; and
- applying said void fraction X_L to a total flow rate Q_{TL} of said majority liquid phase to provide respective a flow rate Q_L of said liquid component and a flow rate Q_G of a gas component of said majority liquid phase.

23. The method (P200) of claim 22 wherein said step of calculating (P214) said void fraction X_L comprises the step of:

performing an iterative convergence calculation.

24. The method (P200) of claim 23 wherein said iterative convergence calculation converges based upon a difference between a measured density value and a theoretical density value based on the void fraction X_L .

25. The method (P200) of claim 24 wherein said step of calculating (P214) said void fraction X_L comprises the step of:

performing a noniterative calculation.

26. The method (P200) of claim 25 wherein said step of calculating (P214) said void fraction X_L comprises the step of:

comparing results from said iterative solution against results from said noniterative calculation to obtain a best answer.

27. The method (P200) of claim 22 further comprising the step of:
- determining a gas density ρ_{gas} at temperature and pressure in a multiphase flow measurement system;
- measuring a liquid density ρ_L of said majority liquid phase;
- 5 calculating (P214) a void fraction X_L based upon a relationship between said density ρ_{meas} determined and said density ρ_L ;
- calculating (P216) a density ρ_{calc} from said gas density ρ_{gas} , said liquid density ρ_L and said void fraction X_L determined from said step of calculating a void fraction X_L .



28. The method (P200) of claim 27 wherein said step of calculating (P216) said density ρ_{calc} operates according to a relationship:

$$P_{calc} = (P_{gas} X_L) + (1 - X_L) P_L.$$

wherein X_1 is a void fraction of said majority liquid component.

29. The method (P200) of claim 28 wherein said step of calculating (P216) a density ρ_{calc} comprising the steps of:

iterating values of ρ_{calc} through successive values of X_L until ρ_{calc} converges within an acceptable range of error with respect to a value ρ_{meas} which is determined from said step of measuring a density ρ_{meas} .

30. The method (P200) of claim 31 wherein said step of iterating values of ρ_{calc} operates according to a relationship:

$$X_{Li} = (P_{calc} - P_{meas}) / P_{calc},$$

wherein $X_{g,i}$ is the gas void fraction based upon an iterative approximation of ρ_{calc} .

31. The method (P200) of claim 30 further including a step of:

calculating (P224) a water cut WC in said majority liquid phase based upon a density ρ_{calc} ;

32. The method (P200) of claim 31 wherein said step of calculating (P224) said water cut operates according to a relationship:

$$WC = (P_{calc} - P_o) / (P_w - P_o),$$

wherein ρ_o is a density of oil in said majority liquid phase, and ρ_w is a density of water
5 in said majority liquid phase.

33. The method (P200) of claim 22 comprises the step of:
measuring (P222) a density ρ_{mgas} of a majority gas phase; and
measuring (P222) a flow rate of said majority gas phase.



34. The method of claim 33 further comprising step of:
calculating a void fraction X_g in said majority gas phase based upon a density
using said density ρ_{mgas} determined from said means for measuring a density ρ_{mgas} .

