US005224372A

United States Patent [19]

Kolpak

[11] **Patent Number: 5,224,372**

[45] **Date of Patent: Jul. 6, 1993**

[54] **MULTI-PHASE FLUID FLOW MEASUREMENT**

[75] Inventor: **Miroslav M. Kolpak**, Plano, Tex.

[73] Assignee: **Atlantic Richfield Company**, Los Angeles, Calif.

[21] Appl. No.: **781,434**

[22] Filed: **Oct. 23, 1991**

Related U.S. Application Data

[63] Continuation-in-part of Ser. No. 523,152, May 14, 1990, Pat. No. 5,090,253.

[51] **Int. Cl.**[5] **G01N 33/00**

[52] **U.S. Cl.** **73/19.03**; 73/19.10

[58] **Field of Search** 73/861.04, 861.37, 861.38, 73/19.01, 19.03, 19.05

[56] **References Cited**

U.S. PATENT DOCUMENTS

3,927,565 12/1975 Pavlin et al. .... 73/861.38 X
4,096,745 6/1978 Riukin et al. .... 73/861.37 X
5,029,482 7/1991 Liu et al. .... 73/861.04 X

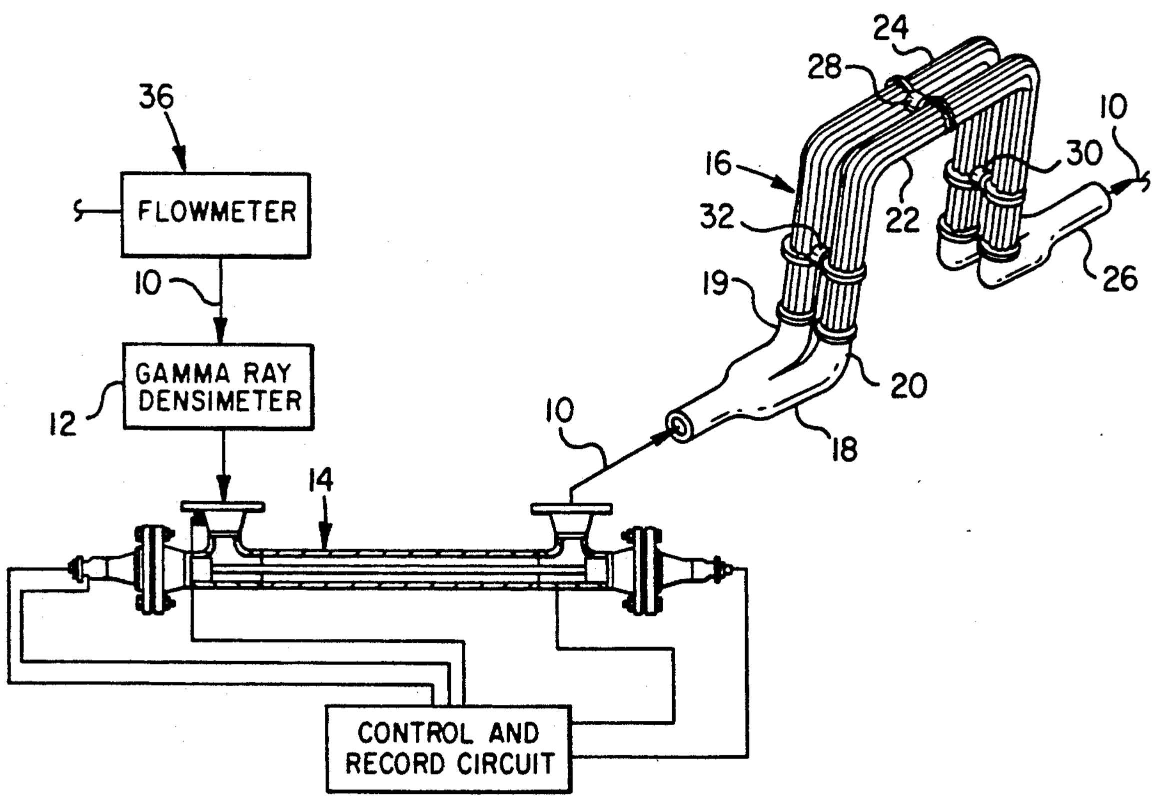
Primary Examiner—Herbert Goldstein

Attorney, Agent, or Firm—Michael E. Martin

[57] **ABSTRACT**

Multiphase (gas and two liquid phases) fluid flowstreams are measured to determine the total flow rate, fluid density, the fraction of gas, and one liquid in the total liquid mixture by passing the flowstream through a Ceriolis flow meter (**16, 40**), a densimeter (**12**) and a meter (**14**) which measures the fraction of one liquid in the two liquid mixture. The total fluid flow rate may be measured by a single tube flow meter (**40**) having adjacent loops which provide tube legs (**49, 51**) positioned adjacent each other and vibrated laterally at a predetermined frequency and amplitude while measuring pressures in the contraflowing streams in the adjacent tube legs. The density and gas fraction of the flowstream may be determined by vibrating a tube containing the flowstream over a range of frequencies and measuring the phase angle and amplitude of the fluctuating fluid pressures compared with acceleration of the tube to determine the sloshing natural frequency of the fluid mixture. The tube may be vibrated at a frequency far from the sloshing natural frequency of the fluid mixture to determine the fluid density.

12 Claims, 2 Drawing Sheets



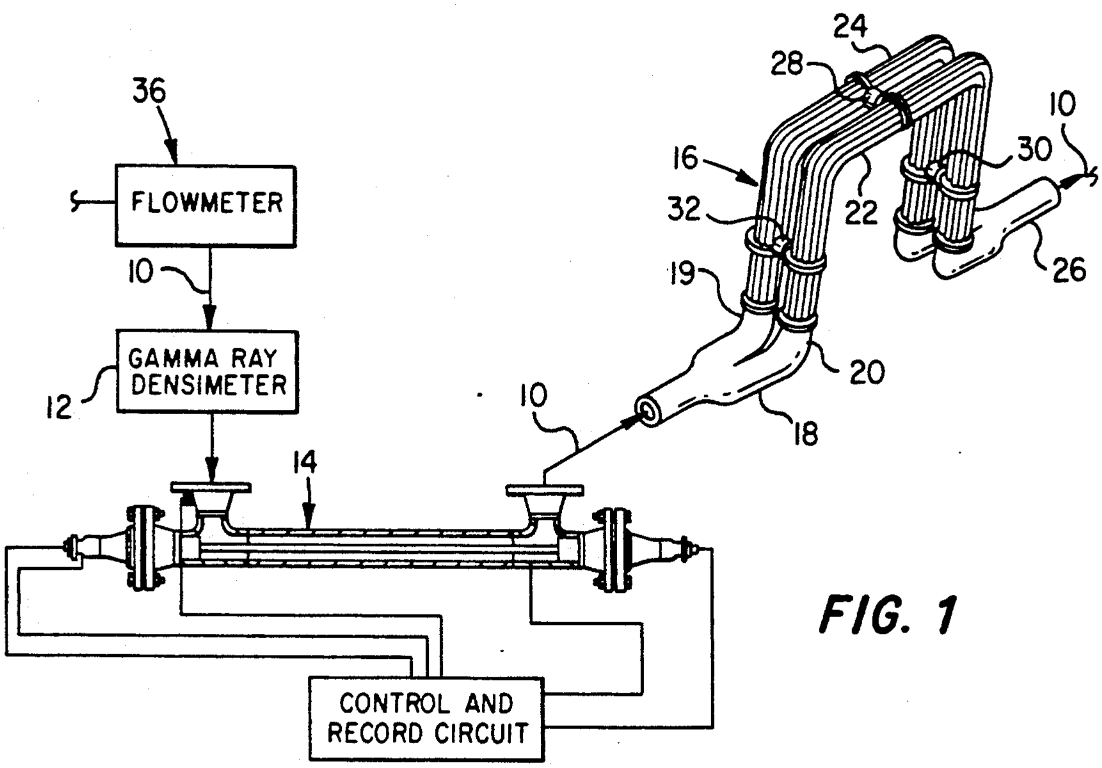


FIG. 1

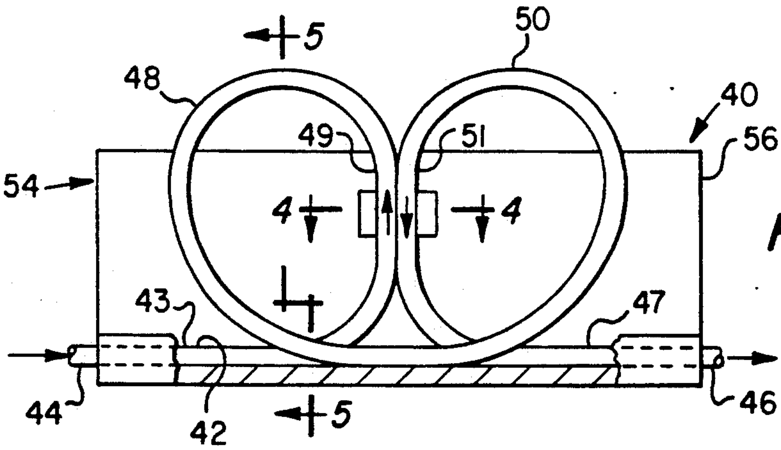


FIG. 2

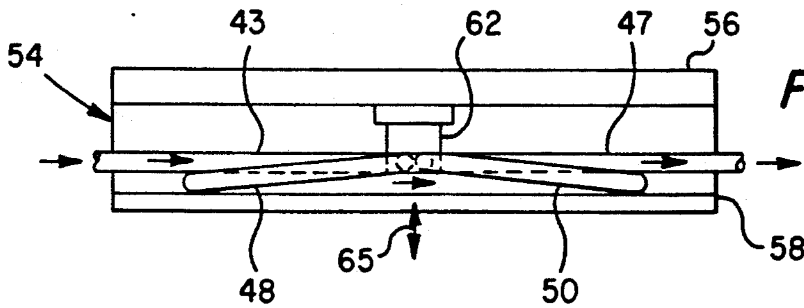
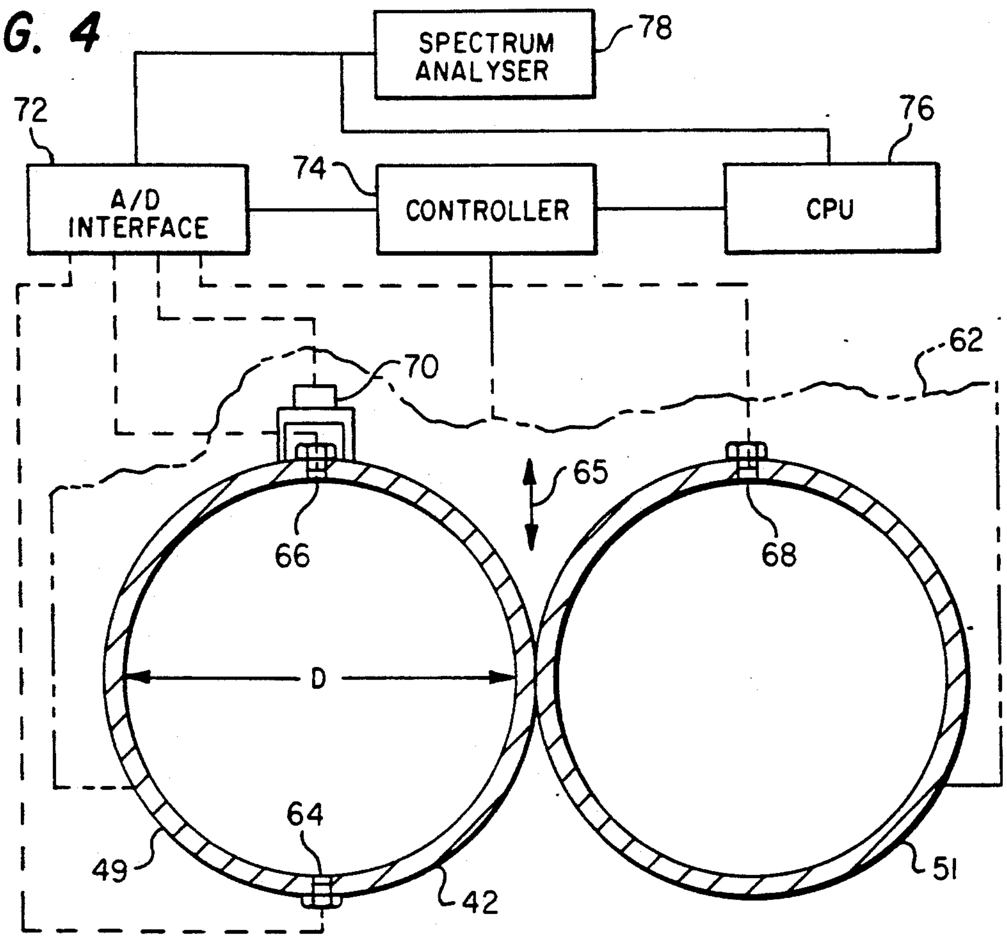


FIG. 3

FIG. 4


SPECTRUM ANALYSER
78
72
76
A/D INTERFACE
74
CONTROLLER
CPU
62
70
65
66
68
D
64
49
42
51

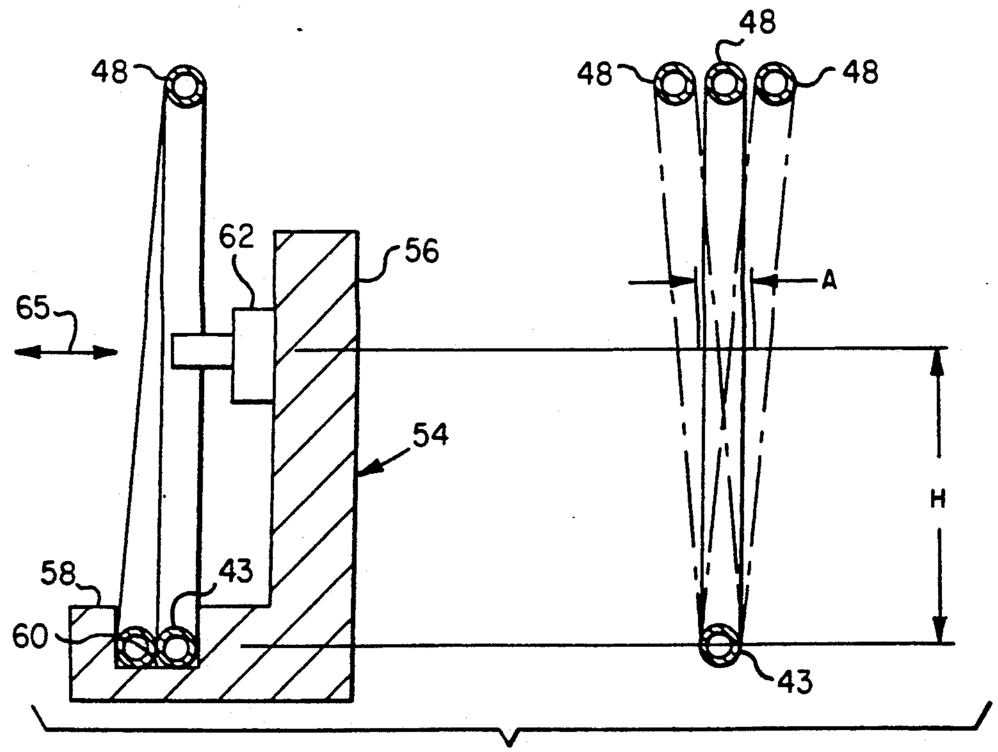

48
48
48
48
62
56
65
A
54
H
58
43
60
43

FIG. 5

MULTI-PHASE FLUID FLOW MEASUREMENT

CROSS REFERENCE TO RELATED APPLICATION

This application is a continuation in part of application Ser. No. 07/523,152, filed May 14, 1990, now U.S. Pat. No. 5,090,253, the subject matter of which is incorporated herein by reference.

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention pertains to methods and apparatus for measuring multi-phase fluid flow such as mixtures of oil, water and gas utilizing a densimeter, a two-phase flow meter based on microwave attenuation characteristics and a mass or volumetric flow meter such as a modified coriolis-type flow meter.

2. Background of the Invention

Various techniques and systems have been developed for measuring multi-phase fluid flow, in particular, three phase fluid flow comprising a mixture of oil, water and gas. My U.S. Pat. No. 4,852,395, assigned to the assignee of the present invention describes a system for measuring multiphase fluid flow wherein gas is separated from a mixture of oil and water and the fractions of oil and water are then determined including measuring batch samples to correct for the residual gas content. Although such a system has a high degree of accuracy, it is relatively mechanically complex and requires a gas separator and gas flow meter.

Mechanically simple flow meters are sought for many applications, particularly in applications for measuring the multiphase fluid emanating from oil and gas wells wherein essentially, mixtures of water, hydrocarbon liquids, such as crude oil; and gas are continually produced in varying proportions of the total fluid flowstream. The present invention provides new and unique methods for measuring multiphase fluid flow, particularly of the type above described, as well as improved apparatus for measuring such multiphase fluid flow, which overcomes some of the problems associated with prior art methods and systems.

SUMMARY OF THE INVENTION

The present invention provides improved methods for measuring multiphase fluid flow, such as mixtures of oil, water and gas.

In accordance with one aspect of the present invention a method is provided for measuring the oil, water and gas flow rates of a multiphase fluid flowstream without completely separating any of the fluid fractions from the flowstream. A system for practicing the method includes a meter which measures the oil and water fractions of the flowstream, a densimeter and a coriolis type flow meter. The oil-water fraction or "watercut" meter may be one of several types but is preferably one based on microwave attenuation characteristics which vary with the fraction of oil and water, respectively. The coriolis type flow meter may be of the type described in co-pending U.S. patent application Ser. No. 07/523,152.

In another system and method according to the invention, the fractional volumetric flow rates may be determined using only, in combination, the watercut meter and the modified coriolis type flow meter.

The present invention still further provides unique methods and apparatus for determining the gas fraction and density of a multiphase fluid mixture utilizing a single continuous tube type device which is vibrated substantially at the sloshing resonant frequency of the fluid mixture, or determining the density of a fluid mixture by vibrating the device at a frequency substantially away from the sloshing resonant frequency. Still further, there is provided a method and system utilizing a single continuous tube type flow meter with tube portions wherein the fluid flow at a predetermined point is in opposite directions and wherein the difference in fluid pressures at selected locations in the tube are measured to determine mass flow rate.

Those skilled in the art will recognize the above-described advantages and superior features of the present invention together with other important aspects thereof upon reading the detailed description which follows in conjunction with the drawing.

BRIEF DESCRIPTION OF THE DRAWING

FIG. **1** is a schematic diagram illustrating one combination of measurement devices used in conjunction with the methods of the present invention.

FIG. **2** is a side elevation of a single continuous tube type flow measuring apparatus in accordance with the present invention;

FIG. **3** is a top plan view of the apparatus shown in FIG. **2**;

FIG. **4** is a section view taken along the line **4—4** of FIG. **2** illustrating an arrangement which is used in conjunction with a method of the present invention;

FIG. **5** is a section view taken along line **5—5** of FIG. **2** and including a diagram illustrating some of the dimensions used in accordance with the method of the present invention.

DESCRIPTION OF PREFERRED EMBODIMENTS

In the description which follows like parts are marked throughout the specification and drawing with the same reference numerals, respectively. The drawing figures are not to scale and certain features are shown in schematic form in the interest of clarity and conciseness. Referring to FIG. **1**, there is illustrated a conduit **10** which is operable to conduct a multiphase fluid flowstream, such as might result from the production of crude oil from a well, and which typically includes a mixture of crude oil, water and gas. The systems and methods described herein are more accurate when the gas content of the fluid flowstream is less than about twenty percent (20%) of the total. Preliminary separation of gas might be necessary in some situations in order to prepare the flowstream for measurements by the system of the present invention. In FIG. **1**, four separate devices are shown interposed in the conduit **10** and which devices may be used in certain combinations or alone to make certain measurements in accordance with the present invention. A densimeter **12** is interposed in the conduit **10** which may be of the so-called gamma ray type, for example. The densimeter **12** may be of a type commercially available, such as a model S-Series "Sensor Net" manufactured by TN Technologies, Inc. of Round Rock, Tex. A second device shown interposed in the conduit **10** for receiving flow of fluid therethrough is a so-called "watercut" meter, generally designated by the numeral **14**, and of the type which measures changes in microwave attenuation resulting from changes in the composition of the fluid flowing therethrough. The meter **14** is preferably of the type disclosed and claimed in U.S. Pat. Nos. 4,862,060 issued Aug. 29, 1989 or 4,996,490 issued Feb. 26, 1991 both to Scott et al. and both assigned to the assignee of the present invention. Suffice it to say that the meter **14** is operable to measure the water fraction of an oil-water mixture which may include certain amounts of gas entrained therein.

FIG. **1** further illustrates a modified coriolis type flow meter, generally designated by the numeral **16**, which may be of the type described in application Ser. No. 07/523,152. Basically, the flow meter **16** comprises an inlet conduit **18** which is split into two branch conduits **19** and **20** which are in communication with respective bundles of smaller diameter tubes **22** and **24**, having a generally U-shaped configuration, and connected to an outlet manifold **26** similar to the manifold or conduit **18**. The tube bundles **22** and **24** are vibrated in a generally lateral direction with respect to their longitudinal central axes by suitable vibrator means **28** and the vibrations of the respective upstream and downstream legs of the tube bundles **22** and **24** are sensed by vibration sensors **30** and **32**. Further details of the flow meter **16** may be obtained by referring to the above-referenced patent application.

In accordance with a first method the gas, water and oil flow rates in a multi-phase fluid flowstream flowing through the conduit **10** may be determined utilizing the densimeter **12**, a meter such as the meter **14**, and the coriolis flow meter **16**, for example. The densimeter **12** provides measurement of the total fluid mixture density, dm, and the coriolis flow meter **16** provides measurement of the apparent mixture density, dma, which is related to the true mixture density, dm, by the equation:

$$dm = dma(1 + A2 * fg + A3 * fg^2) \quad (1)$$

where A2 and A3 are coefficients which may be determined earlier by calibration of the meter **16** in gassy liquid flow wherein small uniformly distributed gas bubbles are present in the range of zero percent (0%) to twenty percent (20%) by volume in the liquid, and fg is the gas fraction of the multi-phase fluid flowstream. Equation (1) may be solved for the gas fraction, fg, which then takes the form:

$$fg = \frac{\sqrt{A2^2 - 4A3(1 - dm/dma)}}{2A3} \quad (2)$$

The coriolis type flow meter **16**, is operable to provide a measurement of the apparent mass flow rate of the fluid flowstream, Ma, which is related to the true mass flow rate, M, by the equation:

$$M = Ma(1 + A4 * fg + A5 * fg^2 + \ldots) \quad (3)$$

where A4, A5, . . . are coefficients which are also determined earlier by calibration of the coriolis meter **16** in gassy liquid flow wherein small uniformly distributed gas bubbles are present in the range of zero percent (0%) to twenty percent (20%) by volume, in the liquid.

The oil, water and gas volumetric flow rates Qo, Qw, and Qg are computed by:

$$Qo = Qm(1 - fg)(1 - wc) \quad (4)$$

$$Qw = Qm(1 - fg) * wc \quad (5)$$

$$Qg = Qm * fg \quad (6)$$

where Qm is the volumetric flow rate of the fluid mixture determined by:

$$Qm = M/dm \quad (7)$$

where dm and M are computed by equations (1) and (3) substituting the value of the gas fraction, fg, determined in equation (2) and the value of the water fraction, wc, as determined by the meter **14**. The method just described above provides volumetric flow rates for the oil fraction, the water fraction and the gas fraction without the need of knowing the density of each of these components.

On the other hand, in situations where the water density, the oil density and the gas density are known or are easily measured and are relatively stable from time to time over the period where flow measurement is desired, the flow rates of each of the fractions of gas, water and oil in the multi-phase flowstream may be determined by a second method using a watercut meter and a modified coriolis type meter such as the meters **14** and **16**, respectively. The coriolis meter **16** will provide a measurement of the apparent density of the mixture, dma, which may be used to determine the true density, dm, from equation (1). The gas fraction, fg, is related to the density values and the water fraction (on a volumetric basis) by the following equation:

$$fg = [wc(dw - do) + (do - dm)]/[wc(dw - do) + (do - dg)] \quad (8)$$

where fg is the gas fraction, wc is the water fraction measured by the meter **14**, do is the oil density, dw is the water density and dg is the gas density.

Simultaneous solution of equations (**1**) and (**8**) yields

$$fg = \frac{\sqrt{b^2 - 4ac}}{2a}$$

where

$$a = dma * A3 \quad (9)$$

$$b = dma * A2 + wc(dw - do) + (do - dg) \quad (10)$$

$$c = dma - wc(dw - do) - do \quad (11)$$

wc=measured by meter 14

dma=measured by coriolis meter 16

do,dw,dg=known (measured) densities of oil, water and gas

The oil, water and gas flow rates Qo, Qw, and Qg may then be computed using equations (4) through (6). Accordingly, a method utilizing only two meters, namely the meters **14** and **16** may be used if the densities of the fluid fractions can be measured and remain relatively constant. Inaccuracies caused by imprecise knowledge of the oil density and the water density when oil gravity is low (API gravity approaches about 10) do not occur.

In accordance with a third method of the present invention, the flow rates of the fractional fluid components of a multi-phase fluid flowstream flowing through the conduit **10** may be determined utilizing a watercut

DOCKET ALARM

Explore Litigation Insights

Docket Alarm provides insights to develop a more informed litigation strategy and the peace of mind of knowing you're on top of things.

Real-Time Litigation Alerts

Keep your litigation team up-to-date with **real-time alerts** and advanced team management tools built for the enterprise, all while greatly reducing PACER spend.

Our comprehensive service means we can handle Federal, State, and Administrative courts across the country.

Advanced Docket Research

With over 230 million records, Docket Alarm's cloud-native docket research platform finds what other services can't. Coverage includes Federal, State, plus PTAB, TTAB, ITC and NLRB decisions, all in one place.

Identify arguments that have been successful in the past with full text, pinpoint searching. Link to case law cited within any court document via Fastcase.

Analytics At Your Fingertips

Learn what happened the last time a particular judge, opposing counsel or company faced cases similar to yours.

Advanced out-of-the-box PTAB and TTAB analytics are always at your fingertips.

API

Docket Alarm offers a powerful API (application programming interface) to developers that want to integrate case filings into their apps.

LAW FIRMS

Build custom dashboards for your attorneys and clients with live data direct from the court.

Automate many repetitive legal tasks like conflict checks, document management, and marketing.

FINANCIAL INSTITUTIONS

Litigation and bankruptcy checks for companies and debtors.

E-DISCOVERY AND LEGAL VENDORS

Sync your system to PACER to automate legal marketing.