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(54) SEPARATOR SYSTEM AND MULTIPHASE METERING METHOD

SEPARATORSYSTEM UND MEHRPHASIGES MESSVERFAHREN

SYSTÈME SÉPARATEUR ET PROCÉDÉ DE COMPTAGE MULTIPHASE

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(73) Proprietor: **Invensys Systems, Inc.**
Foxboro, MA 02035 (US)

(72) Inventors:

- **Manus, Henry P.**
Oxford, Oxfordshire OX3 7TR (GB)

• **Cashimiro, Richard**

North Kingstown, RI Rhode Island 02852 (US)

(74) Representative: **Friese Goeden Patentanwälte
PartGmbB**

**Widenmayerstraße 49
80538 München (DE)**

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Description**FIELD OF INVENTION**

5 [0001] The present invention relates generally to systems and methods for metering multiphase flows, and more particularly to systems and methods for metering flow from a multiphase fluid source, such as a petroleum well, that may produce a multiphase flow having variable content.

BACKGROUND

10 [0002] In the oil and gas industry, the output of a production well is usually a multiphase mixture of oil, water, and gas, commonly referred to as three-phase flow. The gas itself can be present in two forms: as free gas in the form of bubbles or slugs, or as dissolved gas tightly bound to the liquid. The relative proportions of free and dissolved gas vary with many factors, most notably pressure. Thus, for the same well production stream with constant mass flow rates of oil, water
15 and gas, the proportion of gas coming out of solution to become free gas will increase as the line pressure decreases downstream. Accurate assessment of the output of each well is important for reservoir management, as well as for the payment of royalties and taxation.

20 [0003] The output of each petroleum well could be measured on a continuous basis with a dedicated metering system capable of monitoring the three phase simultaneously. Such a device is known as a three-phase flow meter. Unfortunately, it is at present uneconomic to meter wells individually using dedicated three-phase flow meters. As discussed below, the most widely used system for measuring three-phase flow is the separator, which physically separates at least the gas and the liquid. In many separator systems the oil and water are also separated. Separator systems are large and expensive, and it is uneconomic to provide a separator for each well. Instead, the industry has developed the practice
25 of using well test stations, where the outputs of many wells are brought together to share a single multiphase measurement system, i.e. a test separator.

30 [0004] Referring to Fig. 1, a conventional well test separator selects 1 of N wells (where N is typically 6 - 60) and directs the multiphase flow from a well that has been selected for testing into a separator system so that the well output can be tested or measured. The outputs from all the unselected wells are typically pooled and sent unmeasured to the production facility, bypassing the test separator. Once the testing of the selected well is complete, a different well can be selected for testing. Thus, all N wells can eventually be tested one at a time using the conventional test separator.

35 [0005] Figure 2 shows a conventional separator system in more detail. The multiphase flow is directed into a separator vessel, which has sufficient capacity to enable the gravimetric separation of at least the liquid (e.g., oil and water) from the gas. Other separator designs have additional features to enable the further separation of the oil from the water. The separated gas rises, and is piped away on the "gas leg" to be metered by a suitable gas flow measurement device, such as a vortex meter or a Coriolis mass flow meter. Similarly, the liquids are piped away on the "liquid leg" to be metered by a suitable liquid flow measurement device, such as a positive displacement meter, a vortex meter, or a Coriolis mass flow meter. Further measurements can be taken to determine the 'water cut', or proportion by volume of water within the liquid mixture, so that the individual oil and water flow rates can be calculated. For example, a water cut meter can be incorporated into the liquid leg. Alternatively, if a Coriolis meter is used to meter the liquid, its density reading can be
40 used to determine the water cut.

45 [0006] A range of techniques, familiar to those skilled in the art, may be used to manage the separation and measurement of the liquid and gas streams by conventional separator systems. Typically, level and/or pressure control is used. For example, the level of the liquid in the separator may be maintained between an upper and lower limit, or the pressure at the top of the separator may be maintained between an upper and lower pressure limit, or some combination of the two may be implemented. Flow out of the separator through the liquid and/or gas legs may occur continuously or in batches, depending upon the control scheme implemented. In any event, phase separation entails gravimetric separation of the various constituents of the multiphase flow, which requires the separator tank or vessel to be large enough to provide a suitable settling time for allowing gravimetric separation of the fluids. Because of the settling time in the separator vessel, there is no way to correlate instantaneous gas or liquid flow rate measurements with any instantaneous flow rates into the separator vessel. In other words, there is no way to correlate the instantaneous oil, water and gas flow rates of the well being tested with the instantaneous flow outputs from the separator.

50 [0007] For example, Figure 3 shows the observed flow pattern from a conventional separator as it monitors an oil and gas well over a two hour test period. The upper plot shows the flow measurement reported on the liquid leg, in tons per day (t/d), while the lower graph shows the reported flow measurement on the gas leg, in standard cubic meters per day. In this example, the separator control scheme operates so that liquid normally flows through the liquid leg meter, but from time to time (for example when the pressure in the separator reaches an upper limit) a gas purge takes place, where the liquid leg is shut off and the gas leg is opened up to expel gas from the separator and meter the gas. Each gas purge is characterized by an initial spike in gas flowrate, followed by a sharp decline and then a more gradual decline.

When the separator pressure drops to its lower limit, the gas leg is closed and the liquid leg is reopened.

[0008] Over a sufficiently long period the flow entering the separator must equal the flow leaving the separator. However, the original flow behavior from the well is largely destroyed by the separation process. The pattern of flow exiting the separator and recorded by the gas and liquid meters is mostly determined by the separator control scheme, not the pattern of flow entering the separator. For example, it is likely that the gas flow rate from the well is more continuous than the pattern of gas purges observed in the gas leg. Thus, no real-time information on the pattern of well flow is provided by this conventional separator system. Typically, therefore, for each well test, only the totalized flows of gas and liquid (sometimes further distinguished as oil and water) are reported, along with the totalized time. Thus, a separator can be used to determine average flow rates for each of the phases, but not the dynamic flow behavior.

[0009] A further limitation of separators, which follows from this interrupted pattern of flow, is that a long testing period is often necessary to ensure accurate measurements. For example, in Figure 3, the time delay between gas purges is up to 50 minutes. If the test had been completed immediately before the final gas purge, say at 11:30, the average gas flow rate reported would have been quite different. Thus, given that the gas and/or liquid streams may leave the separator in a series of cycles, it is important to ensure the test period is long enough to have sufficient separator cycles so that incomplete cycles at the beginning or end of the test period do not introduce significant errors. When switching between wells that are being tested, it also is important to set aside sufficient time to flush the separator through completely with the new well stream before starting a new test or additional measurement errors will be introduced. These issues limit the ability to test wells quickly.

[0010] Figure 4 illustrates another problem that can occur when using a conventional test separator. If gas/liquid separation is incomplete (e.g., if an emulsion is formed, or if the separator is undersized for the well flow rate), then gas carry under and/or liquid carry over may take place. Gas carry under occurs when gas leaves the separator through the liquid leg. Liquid carry over occurs when liquid leaves the separator through the gas leg. Figure 4 shows liquid carry-over occurring at the very start of a test period, in data collected from the same separator with the same control schemes as shown in Figure 3. The top graph shows the liquid flow rate leaving the separator, which is essentially steady other than the regular drops in flow when the liquid leg is closed for gas purges. The middle graph shows the gas flow rate reading from a Coriolis mass flow rate meter on the gas leg. There are regular bursts of gas flow coinciding with each of the pauses in liquid flow, as expected, but the graph is dominated by the first burst of gas occurring at time 16:25. The bottom graph shows the density reading from the Coriolis meter on the gas leg. The density time series demonstrates that for much of the test the density is around 30 kg/m³, which is the expected value for the gas composition and the operational pressure. However, at the initial purge of gas at time 16:25, the density rises to above 400 kg/m³. This can only have been caused by liquid carry-over, where liquid is carried through into the gas leg, resulting in a very high density reading from the Coriolis meter on the gas leg. In this case the liquid carry over appears to cause a large over-reading of the gas mass flow before the end of the liquid carry over event. Similarly, in the case of gas carry under, when gas/liquid separation is incomplete it is possible for some gas to be passed through the liquid leg, which may introduce errors in the liquid flow meter. Gas carry under in the liquid leg can be detected by density readings from the liquid leg that are too low.

[0011] A related potential problem with the conventional separator arrangement in Fig. 2 concerns the effects of dissolved gas. As is well known to those familiar with the industry, natural gas readily dissolves in oil. The amount of gas dissolving in the oil is a function of several parameters, including temperature and pressure. Specifically, at higher pressures more gas can be dissolved into a given volume of oil. Accordingly, at each stage of the upstream oil and gas production process, whenever the pressure decreases, some gas will be released from solution in the oil. Thus, even when there is no gas carry under, the pressure drop across the liquid meter will induce a proportion of gas to come out of solution, and in that sense the fluid measured in the liquid leg is not purely liquid because of the gas therein. Even small amounts of gas coming out of solution can cause significant measurement errors in some conventional liquid phase meters, for example some conventional Coriolis meters.

[0012] Moreover, each separator is typically used to test the outputs from many wells, and so must be designed to deal with the range of flow conditions across all these wells, as characterized by liquid volumetric flowrate, water cut, GVF, pressure and other parameters. Choosing the most appropriate capacity for a separator, given the set of wells to be tested, is a matter of balancing different considerations. It is desirable to minimize the separator size in order to keep the cost of construction as low as possible. However, if the capacity of the separator is too small for high flowing wells, the separation process may be incomplete, leading to liquid carry over and/or gas carry under with the likelihood of measurement errors induced in the gas and liquid leg flow meters. On the other hand, if the capacity of the separator is too large, then for low flowing wells the test period may need to be significantly extended to ensure sufficient separator gas purge cycles for the desired measurement accuracy. In practice, a single separator can be used in the industry to measure a well cluster with a wide range of well flow rates - for example a ratio of 20:1 - between the highest and lowest liquid flow rate. However, the need to accommodate a wide range of flow rates does limit the options available for well testing.

[0013] WO 01/31298 A2 discloses a system for testing production of fluids by a petroleum well according to the

preamble of claim 1.

[0014] The present inventor has developed systems and methods that improve on the conventional systems described above and which will be described in detail below.

5 SUMMARY

[0015] One aspect of the invention is a system for testing production of fluids by one or more petroleum wells. The system includes a separator. The separator has an inlet for receiving a multiphase fluid flow from a petroleum well, a vessel for containing fluids received through the inlet, a liquid outlet, and a gas outlet. The gas outlet is positioned at a higher elevation on the vessel than the liquid outlet. The system also includes first and second multiphase flow metering systems. Each of the first and second multiphase flow metering systems has the capability, over at least a portion of its operating envelope, of separately measuring flow rates of oil, water, and gas through the respective flow metering system. The system also includes a fluidic system that has: (i) gas leg conduits fluidically coupling the gas outlet of the separator to the first and second multiphase flowmeters; (ii) liquid leg conduits fluidically coupling the liquid outlet of the separator to the first and second multiphase flow metering systems; (iii) bypass conduits plumbed to direct multiphase fluid through the fluidic system to the first and second multiphase flow metering systems without flowing the fluid through the separator to thereby bypass the separator; and (iv) a plurality of valves configured to selectively control routing of fluid flow through the fluidic system.

[0016] Another aspect of the invention is a method of testing fluids produced by individual petroleum wells in a group of N petroleum wells using the above described system. The method includes routing fluid from one or more wells selected for testing to a well test system. The well test system including a separator vessel, a plurality of multiphase metering systems, and a fluidic system for receiving multiphase fluid output from the one or more wells. The method also includes determining whether or not the plurality of multiphase metering systems can, either individually or collectively, provide individual measurements of oil, water, and gas. The fluid is selectively routed to the separator vessel when it is determined the plurality of multiphase metering systems cannot provide individual measurements of oil, water, and gas. The fluid is selectively routed directly to one or more of the plurality of multiphase metering units, bypassing the separator, when it is determined the multiphase metering units can provide individual measurements of oil, water, and gas.

[0017] Other objects and features will in part be apparent and in part pointed out hereinafter.

30 BRIEF DESCRIPTION OF THE DRAWINGS

[0018]

35 FIG. 1 is a schematic diagram of a prior art test separator system being used to test multiphase output from one well selected from a group of N wells;
 FIG. 2 is a schematic diagram of the test separator from Fig. 1;
 FIG. 3 is a set of graphs illustrating flow rates of gas and liquid from the test separator in Fig. 2 during a well test;
 FIG. 4 is a set of graphs illustrating flow rates of gas and liquid as well as measured "gas" density during a liquid carry over event;
 FIG. 5 is a schematic diagram of one embodiment of a multiphase test system of the present invention being used to test a selected well from a group of N wells;
 FIG. 6 is a schematic diagram illustrating the multiphase test system in more detail;
 FIG. 7 is a front elevation of one embodiment of a net oil skid that can be used to measure flow rate of individual components of a three-phase flow from the separator of the multiphase test system illustrated in Figs. 5 and 6;
 FIG. 8 is a schematic diagram illustrating one embodiment of an electronic architecture for the net oil skid illustrated in Fig. 7;
 FIG. 9 is a set of graphs illustrating volumetric fraction for each constituent of a three-phase flow from a petroleum well and flow rate for each constitute of the three-phase flow; and
 50 FIG. 10 is a schematic diagram illustrating one embodiment of an electronic architecture suitable for use in a multiphase test system, such as the multiphase test system illustrated in Fig. 6.

[0019] Corresponding reference characters indicate corresponding parts throughout the drawings.

55 DETAILED DESCRIPTION

[0020] Referring now to the drawings, first to Figs. 5 and 6, one embodiment of a system for testing fluids produced by one or more petroleum wells in a cluster of N wells is generally designated 101.

[0021] The system includes a separator 103, as illustrated in Fig. 6. In general, any device that separates gas from liquids using gravity can be used as the separator. For example, any conventional separator can be used as the separator in the system. As illustrated in Fig. 6, the separator 103 includes an inlet 105 for receiving a multiphase fluid flow from a petroleum well and a vessel 107 for containing fluids received through the inlet. The separator 103 also includes a liquid outlet 109 and a gas outlet 111. The gas outlet 111 is positioned at a higher elevation on the vessel 107 than the liquid outlet 109. In particular, the liquid outlet 109 is suitably positioned near the bottom of the vessel 107 to facilitate draining liquid completely from the vessel and to limit the potential for gas carry under. The gas outlet 111 is suitably positioned near the top of the vessel 107 for discharging gas from the vessel while limiting the potential for liquid carry over.

[0022] In addition to the separator 103, the system also includes a plurality of multiphase flow metering systems 121, 123. Each of the multiphase flow metering systems 121, 123 has the capability to receive a multiphase flow containing oil, water, and gas and provide separate flow rate measurements for flow of oil, water, and gas therethrough over at least a portion of its operating envelope. For example, one or both of the multiphase flow metering systems 121, 123 can suitably include a multiphase Coriolis meter, such as the Coriolis flowmeters described in U.S. Patent Nos. 6,311,136; 6,505,519; 6,950,760; 7,059,199; 7,614,312; 7, 660, 681; 7, 617, 055. One or both of the multiphase metering systems 121, 123 can also include a water cut meter that measures the amount of water in the multiphase flow in combination with a Coriolis flowmeter or other type of flowmeter that is operable to measure liquids (e.g., oil and water) separately from gas.

[0023] Figure 7 illustrates one embodiment of a multiphase metering system 131 that is suitable for use in the system 101. The multiphase metering system 131 illustrated in Fig. 7 is generally known as a net oil skid. The net oil skid 131 in the illustrated embodiment includes a multiphase Coriolis flowmeter 133 in series with a water cut meter 135. Together the Coriolis meter 133 and water cut meter 135 can provide independent measurement of oil, water, and gas flow through the net oil skid 131. For example, the multiphase Coriolis meter 133 can suitably provide separate flow rate measurements for the gas phase and the combined liquid phases (e.g., flow rate of oil plus flow rate of water) while the water cut meter 135 can provide a measurement indicating the percentage of water in the combined liquid phases. Thus, the information provided by the Coriolis and water cut meters 133, 135 enables determination of independent flow rates for each constituent of the three phase oil, water, and gas mixture produced by one or more of the petroleum wells. For example, each net oil skid 131 may include a net oil computer 137 that receives information from the Coriolis meter 133 and also from the water cut meter 135 and computes the flow rates for oil, water, and gas through the net oil skid 131 based on that information. Alternatively, a single net oil computer may be shared by a plurality of multiphase metering systems 131 within the scope of the invention. For example, each of the flow metering systems 121, 123 of the system illustrated in Fig. 6 can be a net oils skid as illustrated in Fig. 7 and they may share a single net oil computer 137. It is understood that different arrangements of Coriolis meters and water cut meters can be used.

[0024] It is not required that the multiphase flow metering systems be able to provide three phase flow measurements under all types of conditions. For example, some Coriolis flowmeters provide suitable measurements when operating under low to moderate gas void fraction conditions (e.g., about 50% GVF or less) but do not operate as well under high gas void fraction conditions (e.g., more than about 50% GVF). Although each of the flowmeters 121, 123 in the illustrated embodiment includes a Coriolis flowmeter 133 in combination with a water cut meter 135, it is understood that Coriolis meters are not required to practice the invention and other types of multiphase flowmeters could be used instead without departing from the broad scope of the invention. It is conceivable that other types of multiphase metering systems may need a different set of operating conditions in order to provide suitably independent measurements of the flow rates for oil, water, and gas.

[0025] The multiphase metering systems 121, 123 can provide total flow measurements for the total amount of oil, water, and/or gas flowing therethrough even when the operating conditions are outside the envelop that is suitable for operation in multiphase mode. In other words, each of the multiphase metering systems 121, 123 suitably has a narrower operating envelop within which they can be operated to provide dynamic multiphase measurements of each component of a three phase mixture of oil, water, and gas and also a broader operating envelop within which they can at least provide useful total flow measurements even if they are outside the narrower envelop that allows measurement of individual flow rates of oil, water, and gas.

[0026] For reasons that will become apparent, it may be desirable for each of the multiphase flow metering systems to have a different maximum flow rate capacity. For example, in a system having two multiphase flow metering systems one of the multiphase flow metering systems suitably has a relatively higher maximum flow rate capacity while the other has a relatively lower maximum flow rate capacity. The multiphase flow metering systems can suitably have different minimum flow rates as well. For example, referring to the embodiment illustrated in Fig. 6, one of the multiphase metering systems 121 suitably has an operating range from about 1 to about 5 units while the other 123 has an operating range from about 5 to about 20 units. In this embodiment, there is no gap between the operating ranges for the metering systems 121, 123. Similarly, the multiphase flow metering systems 121, 123 can be used, either collectively or individually, to measure any total flow rate between the lowest minimum flow rate for the smaller capacity system (e.g., 1 unit) to the sum of the maximum flow rates for both systems (e.g., 25 units).

[0027] A fluidic system 141 connects the separator 103 to the multiphase flow metering systems 121, 123. As illustrated in Fig. 6, for instance, gas leg conduits 143 fluidically couple the gas outlet 111 of the separator 103 to the first and second multiphase flow metering systems 121, 123. Liquid leg conduits 145 fluidically couple the liquid outlet 109 of the separator 103 to the first and second multiphase flow metering systems 121, 123. The fluidic system 141 in Fig. 6 also includes 5 bypass conduits 147 plumbed to direct multiphase fluid through the fluidic system to the first and/or second multiphase flow metering systems 121, 123 without flowing the fluid through the separator 103 to thereby bypass the separator. The fluidic system 141 also includes a plurality of valves 151 configured to selectively control routing of fluid flow though the fluidic system.

[0028] In the embodiment illustrated in Fig. 6, for example, the gas leg conduits 143 include an upstream conduit 143a 10 and a set of downstream conduits 143b arranged so each of the multiphase flow metering systems 121, 123 is connected to the upstream gas leg conduit 143a by one of downstream gas leg conduits 143b. Thus, in Fig. 6 for example the gas leg conduits 143 include two downstream gas leg conduits 143b branching from the upstream gas leg conduit 143a because there are two multiphase flow metering systems 121, 123. The number of downstream gas leg conduits could be increased to accommodate additional multiphase flow metering systems. Similarly, the liquid leg conduits 145 also 15 include an upstream conduit 145a and a set of downstream conduits 145b arranged so each of the multiphase flow metering systems 121, 123 is connected to the upstream liquid leg conduit 145a by one of the downstream liquid leg conduits 145b. Again, additional downstream liquid leg conduits could be added to accommodate additional multiphase flow metering systems, if desired. Likewise, the bypass conduits 147 also include an upstream conduit 147a and a set of downstream conduits 147b arranged so each of the multiphase flow metering systems 121, 123 is connected to the 20 upstream bypass conduit 147a by one of the downstream bypass conduits 147b.

[0029] Still referring to Fig. 6, the plurality of valves include a set of valves 153a, 153b in the gas leg conduits 143 that control flow of fluid through the gas leg conduits. One of the valves 153a in the gas leg conduits is positioned in the upstream gas conduit 143a (e.g., near the separator 103) and is configured to selectively open the gas leg conduits 143 for receiving flow from the gas outlet 111 into the upstream gas leg conduit 143a. Further, each of the downstream gas leg conduits 143b has a valve 153b that is configured to selectively open and close the respective downstream gas leg conduits 143b. Thus, the valves 153b in the downstream gas leg conduits 143b are operable to selectively route fluid flow from the upstream gas leg conduit 143 to one or more of the multiphase flow metering systems 121, 123. For example, the valves 153b in the downstream gas leg conduits can be operated to switch flow through the gas leg conduits 143 back and forth from one of the multiphase flow metering systems 121, 123 to the other to reroute the flow of fluid 30 through the gas leg conduits 143.

[0030] The plurality of valves also includes a set of valves 155a, 155b in the liquid leg conduits 145 that control flow of fluid through the liquid leg conduits. One of the valves 155a in the liquid leg conduits 145 is positioned in the upstream liquid conduit 145a (e.g., near the separator 103) and is configured to selectively open the liquid leg conduits 145 for receiving flow from the liquid outlet 109 into the upstream liquid leg conduit 145a. Further, each of the downstream liquid leg conduits 145b has a valve 155b that is configured to selectively open and close the respective downstream liquid leg conduit 145b. Thus, the valves 155b in the downstream liquid leg conduits 145b are operable to selectively route fluid flow from the upstream liquid leg conduit 145a to one or more of the multiphase flow metering systems 121, 123. For example, the valves 155b in the downstream liquid leg conduits 145b can be operated to switch flow through the liquid leg conduits 145 back and forth from one of the multiphase flow metering systems 121, 123 to the other to reroute 40 the flow of fluid through the liquid leg conduits.

[0031] The plurality of valves also includes a set of valves 157a, 157b in the bypass conduits 147 that control flow of fluid through the bypass conduits. One of the valves 157a in the bypass conduits 147 is positioned in the upstream liquid conduit 147a and is configured to selectively open the bypass conduits for receiving flow directly from the petroleum wells. Further, each of the downstream bypass conduits 147b has a valve 157b that is configured to selectively open 45 and close the respective downstream bypass conduits. Thus, the valves 157b in the downstream bypass conduits 147b are operable to selectively route fluid flow from the upstream bypass conduit 147a to one or more of the multiphase flow metering systems 121, 123. For example, the valves 157b in the downstream bypass conduits 147b can be operated to switch flow through the bypass conduits back and forth from one of the multiphase flow metering systems 121, 123 to the other to reroute the flow of fluid through the bypass conduits 147. The bypass valves 159 also include a valve 50 159c upstream of the separator 103 that is configured to selectively open and close the inlet 105 to the separator 103.

[0032] The system also has a control system 161 configured to control operation of the valves 151 in the fluidic system 141. The control system 161 can reside in one or more components. For example, some or all of the control system 161 can be part of or accompany a net oil computer associated with one or both of the Coriolis meters, such as the net oil computer 137 on the skid 131 illustrated in Fig. 7. Likewise, the processor 161 can be a separate component that 55 communicates (e.g., wirelessly or through communication lines) with other components of the system. Moreover, the functions ascribed to the control system 161 herein can be divided among multiple separate processing components. The control system 161 is suitably also configured to selectively and sequentially route the output of one or more wells selected from a group of N wells to the fluidic system 141 to perform a series of well tests on the wells, for example

using any convention well switching systems (not shown). Moreover, the control system 161 is suitably configured to implement multiple different measurement modes of the metering system 101 by opening and closing selected valves 151 in the fluidic system 141. More information about some of the possible measurement modes will be provided below. In general, however, the control system 161 implements different measurement modes by routing fluid from the petroleum wells through the fluidic system 141 in different ways and changing how measurements of the production fluids are taken. The control system 161 is suitably configured to select from one of several different measurement modes to match current operating conditions (e.g., flow rate into the system, gas void fraction, etc.) to the performance capabilities of the multiphase flow metering systems 121, 123. In general, the control system 161 routes fluid through the fluidic system 141 differently for each mode.

[0033] For example, the control system 161 is suitably configured to operate the bypass valves 157a, 157b, 157c to bypass the separator 103 and use one or more of the multiphase metering systems 121, 123 to provide dynamic measurement of the production fluids, including near real time individual flow rate measurements for oil, water, and gas, when operating conditions are consistent with operation of the multiphase metering systems in this manner. As used herein, the phrase "dynamic measurement" refers to a measurement that provides time varying individual flow rate measurements for oil, water, and gas that can be correlated with the flow rates of the constituents into the system 101 from the well under test. Similarly, a "dynamic measurement mode" is one that provides dynamic measurements.

[0034] Conversely, the control system 161 is suitably configured to operate the valves 151 to direct fluids produced from the wells to the separator 103 when operating conditions are not conducive to use of the multiphase flow metering systems 121, 123 to provide dynamic measurements (e.g., if the gas void fraction is above a threshold amount). When a measurement mode uses the separator 103, the control system 161 operates the valves 151 to route liquids from the separator 103 to one of the multiphase flow metering systems 121, 123 through the liquid leg conduits 145 and to route gas from the separator to the other of the multiphase flow metering systems through the gas leg conduits 143. Since dynamic measurements are more desirable in most cases than non-dynamic measurements, the control system 161 is suitably configured to route all fluid flow received from the well through the bypass conduits 147 when it determines the current operating conditions allow separate flow rate measurements of oil, water, and gas through the system.

[0035] The system 101 can include one or more of several different components configured to provide information for use by the control system 161 to determine whether or not to bypass the separator 103. For example, one or more sensors can be installed in a line leading from the wells to the system 101 to provide information about the gas void fraction and/or total flow rate of fluids currently being directed into the system. The multiphase metering systems 121, 123 will also provide flow rate measurements that can be used by the control system 161 to assess total flow rate of fluid through the system 101. Moreover, the multiphase flow metering systems 121, 123 may also be able to provide information about the gas void fraction or other characteristics of the fluid flow which may be used by the control system 161 to determine which measurement mode to select and when to implement a change in the current measurement mode.

[0036] Several different measurement modes that can be implemented in connection with the system 101 illustrated in Fig. 6 are listed in Table 1 below:

TABLE 1 - Various Measurement Modes

Operating Mode	Liquid Flow Rate	Gas Void Fraction	Separator	Meter 1 (Capacity of 1-5 units)	Meter 2 (Capacity of 5-20 units)	Measurement Quality
1	0-1 units	0 - 100%	In Use	Liquid Leg	Gas Leg	Conventional
2	1-5 units	0 - 50%	Bypassed	Multiphase Flow	Not In Use	Enhanced/Dynamic
3	1-5 units	50-100%	In Use	Liquid Leg	Gas Leg	Conventional
4	5-20 units	0 - 50%	Bypassed	Not In Use	Multiphase Flow	Enhanced/Dynamic
5	5-20 units	50-100%	In Use	Gas Leg	Liquid Leg	Conventional
6	20-25 units	0 - 50%	Bypassed	Multiphase Flow	Multiphase Flow	Enhanced/Dynamic

In the example set forth in Table 1, the 1st multiphase flow metering system 121 has a minimum flow rate of 1 unit and

a maximum flow rate of 5 units. The 2nd multiphase flow metering system 123 has a minimum flow rate of 5 units and a maximum flow rate of 20 units. The liquid flow rate and gas void fraction columns refer to the flow rate and gas void fraction of fluids entering the system.

5 Mode 1 - Very Low Flow Rate

[0037] In Mode 1 the control system 161 operates the valves 151 to direct fluid from the wells to the separator 103. The control system 161 is suitably configured to pick Mode 1 when the total flow rate of fluid into the system is less than the minimum flow rate for the smallest of multiphase metering systems 121. The separator 103 is used because the fluid flow rate is too low to use any of the multiphase flow metering systems 121, 123 to provide dynamic measurements. One of the metering systems 123 is used to measure gas flow from the separator 103 through the gas leg conduits 143 and the other 121 is used to measure liquid flow from the separator through the liquid leg conduits 145. As indicated in Table 1, the smaller multiphase flow metering system 121 is used to measure the liquid because the flow rate of liquid during very low flow rate into the system will better match the operating range of the smaller system and it is expected that the control strategy for operating the separator will result in periodic batches of gas being released, which can be measured by the larger system in spite of the low overall flow rate because gas will typically be released only periodically. The system output during the Very Low Flow Rate Measurement Mode provides conventional type measurements on the liquid leg and gas leg respectively. In other words, the measurements are accurate when totalized or averaged over a sufficiently long time period, but dynamic measurements are not available due to the settling time in the separator 103 and/or control strategies that may be used to control operation of the separator.

Mode 2 - Low Flow Rate Dynamic

[0038] In Mode 2 the control system 161 operates the valves 151 to bypass the separator 103 and direct all flow from the wells through the bypass conduits 147 to the smallest of the multiphase flow metering systems 121. The control system 161 is configured to pick Mode 2 when the flow rate is within the operating range of the smallest multiphase flow metering system 121 and the gas void fraction is within the specifications for operation of the smaller multiphase metering system in a dynamic multiphase mode (e.g., GVF is less than a threshold value, such as about 50% or less). In the Low Flow Rate Dynamic Measurement Mode, the control system 161 directs all fluids received by the system 101 to the smallest multiphase flow metering system 121, which provides enhanced dynamic multiphase measurements.

Mode 3 - Low Flow Rate Conventional

[0039] In Mode 3 the control system 161 operates the valves 151 to direct all flow received by the system 101 to the separator 103. The control system 161 is suitably configured to pick Mode 3 when the flow rate is within the specifications for the smallest multiphase flow metering system 121 but the gas void fraction is too high to use the metering systems 121, 123 to obtain dynamic measurements. One of the metering systems 123 is used to measure gas flow from the separator 103 through the gas leg conduits 143 and the other 121 is used to measure liquid flow from the separator through the liquid leg conduits 145. As indicated in Table 1 the smaller system 121 is used to measure the liquid because the flow rate of liquid through the system 101 will better match the operating range of the smaller metering system. The system output during the Low Flow Rate Conventional Measurement Mode is conventional type measurements on the liquid leg and gas leg respectively.

Mode 4 - Medium Flow Rate Dynamic

[0040] In Mode 4 the control system 161 operates the valves 151 to bypass the separator 103 and direct all flow from the wells through the bypass conduits 147 to the larger of the multiphase flow metering systems 123. The control system 161 is configured to pick Mode 4 when the flow rate is within the operating range of the larger multiphase flow metering system 123 and the gas void fraction is within the specifications for operation of this system in a dynamic multiphase mode (e.g., GVF is less than a threshold value, such as about 50% or less). In the Medium Flow Rate Dynamic Measurement Mode, the control system 161 directs all fluids received by the system 101 to the larger of multiphase flow metering system 123, which provides enhanced dynamic multiphase measurements.

Mode 5 - Medium Flow Rate Conventional

[0041] In Mode 5 the control system 161 operates the valves 151 to direct all flow received by the system 101 to the separator 103. The control system 161 is suitably configured to pick Mode 5 when the flow rate is within the specifications for the larger multiphase flow metering system 123 but the gas void fraction is too high to use that metering systems to

obtain dynamic measurements. One of the metering systems 121 is used to measure gas flow from the separator 103 through the gas leg conduits 143 and the other 123 is used to measure liquid flow from the separator through the liquid leg conduits 145. As indicated in Table 1 the larger system 123 is used to measure the liquid because the flow rate of liquid through the system 101 will better match the operating range of the larger metering system. The system output
5 during the Medium Flow Rate Conventional Measurement Mode is conventional type measurements on the liquid leg and gas leg respectively.

Mode 6 - High Flow Rate Dynamic

- 10 [0042] In Mode 6 the control system 161 operates the valves 151 159 to bypass the separator 103 and direct all flow from the wells through the bypass conduits 147 to the multiphase flow metering systems 121, 123, which are used in parallel. The control system 161 is configured to pick Mode 6 when the flow rate is above the maximum flow rate capacity of the larger metering system 123 but within the operating range of both metering systems 121, 123 working in parallel to collectively measure all the fluid and the gas void fraction is within the specifications for operation of the metering
15 systems in a dynamic multiphase mode (e.g., GVF is less than a threshold value, such as about 50% or less). In the High Flow Rate Dynamic Measurement Mode, all of the valves 157a, 157b in the bypass conduits 147 are open to provide maximum capacity. Meanwhile the valve 159c controlling the inlet 105 to the separator 103 is closed to prevent flow of fluid into the separator.
- 20 [0043] The various modes set forth above are provided for illustrative purposes. The cutoff points between modes, the criteria used to pick a particular mode, and the way fluid is routed through the system can be varied without departing from the broad scope of the invention. Also, the number of multiphase flow metering systems can be increased from two to three or more. For example, the gas leg conduits, liquid leg conduits, and bypass conduits can include additional downstream conduits connecting the respective upstream conduits to additional multiphase flow metering systems.
- 25 [0044] The system 101 described herein allows dynamic multiphase measurements to be provided over a wide range of potential well-flow rates. Existing conventional separation-based well test systems can easily be upgraded to create the system 101 by adding the multiphase flow meters 121, 123 and conduits 143, 145, 147 to the existing systems. Moreover, the system 101 is also suitable for use in new installations. The system 101 can also provide improved robustness to gas carry under, liquid carry over, and dissolved gas breakout when the separator 103 is in because the multiphase meters 121, 123 can still provide multiphase measurements, and thereby detect presence of gas in the
30 separated liquid and/or presence of liquid in the separated gas, even when the system is not operating in a dynamic mode. Thus, liquid carry over, gas carry under, gas breakout, and other such events can be detected by the system 101. This increased robustness can also make it reasonable to reduce the size and cost of the separator 103 because it may no longer be considered as important to achieve complete separation under the full range of operating conditions that could be encountered.
- 35 [0045] When introducing elements of aspects of the invention or the embodiments thereof, the articles "a," "an," "the," and "said" are intended to mean that there are one or more of the elements. The terms "comprising," "including," and "having" are intended to be inclusive and mean that there may be additional elements other than the listed elements.
- 40 [0046] In view of the above, it will be seen that several advantages of the aspects of the invention are achieved and other advantageous results attained.
- 45 [0047] Not all of the depicted components illustrated or described may be required. In addition, some implementations and embodiments may include additional components. Variations in the arrangement and type of the components may be made without departing from the scope of the claims as set forth herein. Additional, different or fewer components may be provided and components may be combined. Alternatively or in addition, a component may be implemented by several components.
- 50 [0048] The above description illustrates the aspects of the invention by way of example and not by way of limitation. This description enables one skilled in the art to make and use the aspects of the invention, and describes several embodiments, adaptations, variations, alternatives and uses of the aspects of the invention, including what is presently believed to be the best mode of carrying out the aspects of the invention. Additionally, it is to be understood that the aspects of the invention is not limited in its application to the details of construction and the arrangement of components set forth in the following description or illustrated in the drawings. The aspects of the invention are capable of other embodiments and of being practiced or carried out in various ways. Also, it will be understood that the phraseology and terminology used herein is for the purpose of description and should not be regarded as limiting.
- 55 [0049] Having described aspects of the invention in detail, it will be apparent that modifications and variations are possible without departing from the scope of aspects of the invention as defined in the appended claims. It is contemplated that various changes could be made in the above constructions, products, and process without departing from the scope of aspects of the invention. In the preceding specification, various preferred embodiments have been described with reference to the accompanying drawings. It will, however, be evident that various modifications and changes may be made thereto, and additional embodiments may be implemented, without departing from the broader scope of the aspects

of the invention as set forth in the claims that follow. The specification and drawings are accordingly to be regarded in an illustrative rather than restrictive sense.

5 **Claims**

1. System (101) for testing production of fluids by one or more petroleum wells, the system comprising:
 - a separator (103) comprising an inlet (105) for receiving a multiphase fluid flow from a petroleum well, a vessel (107) for containing fluids received through the inlet, a liquid outlet (109), and a gas outlet (111), the gas outlet being positioned at a higher elevation on the vessel than the liquid outlet;
 - first and second multiphase flow metering systems (121, 123), each of the first and second multiphase flow metering systems having the capability, over at least a portion of its operating envelope, of separately measuring flow rates of oil, water, and gas through the respective flow metering system;
- 10 **characterized by**
 a fluidic system (141) comprising: (i) gas leg conduits (143) fluidically coupling the gas outlet of the separator to the first and second multiphase flowmeters; (ii) liquid leg conduits fluidically coupling the liquid outlet of the separator to the first and second multiphase flow metering systems; (iii) bypass conduits (147) plumbed to direct multiphase fluid through the fluidic system to the first and second multiphase flow metering systems without flowing the fluid through the separator to thereby bypass the separator; and (iv) a plurality of valves (151) configured to selectively control routing of fluid flow though the fluidic system.
2. System according to claim 1 wherein the gas leg conduits (143), liquid leg conduits (145), and bypass conduits (147) each comprises a first conduit configured to direct fluid to the first multiphase flow metering system and a second conduit configured to direct fluid to the second multiphase flow metering system, wherein said plurality of valves preferably includes a valve for each of the first conduits and a valve for each of the second conduits, the valves for the first and second conduits being configured to selectively open and close the respective conduit.
 3. System according to any of the preceding claims wherein the first multiphase flow metering system (121) has a relatively higher maximum flow rate capacity and the second multiphase flow metering system (123) has a relatively lower maximum flow rate capacity.
 4. System according to any of the preceding claims wherein the first multiphase flow metering system (121) comprises a multiphase Coriolis flowmeter and/or the second multiphase flow metering system (123) comprises a multiphase Coriolis flowmeter.
 5. System according to any of the preceding claims wherein each of the first and second multiphase flow metering systems (121, 123) comprises a multiphase Coriolis flowmeter in combination with a water cut meter.
 6. System according to any of the preceding claims further comprising a control system (161), the control system being configured to use the valves to implement multiple different measurement modes, wherein fluid is routed differently through the fluidic system in each of the modes.
 7. System according to claim 6 wherein at least one of the measurement modes is a dynamic measurement mode in which fluid is routed through the bypass conduits to bypass the separator and at least one of the other measurement modes is a separated measurement mode in which fluid is routed to the separator for separation into liquids and gas and then liquids are routed from the separator to one of the first and second multiphase flowmeters and gas is routed from the separator to the other of the first and second multiphase flowmeters.
 8. System according to claim 6 or 7 wherein the control system (161) is further configured to:
 - determine whether or not the current operating conditions allow the first and second multiphase flow metering systems, collectively or individually, to provide separate flow rate measurements of oil, water, and gas through the system; and
 - route all fluid flow received from the well through the bypass conduits when the controller determines the current operating conditions allow separate flow rate measurements of oil, water, and gas through the system.

9. System according to claim 8 wherein the first multiphase flow metering system (121) has a relatively higher maximum flow rate capacity and the second multiphase flow metering system (123) has a relatively lower maximum flow rate capacity and wherein the control system (161) is further configured to:

5 determine a current flow rate received from the well; and
 implement a low flow rate dynamic measurement mode when: (i) the controller determines the current operating conditions allow separate flow rate measurements of oil, water, and gas through the system; and (ii) the current flow rate is below a threshold amount corresponding to the maximum flow rate capacity of the second multiphase flow metering system, wherein implementing the low flow rate dynamic measurement mode comprises operating the valves to direct substantially all fluid flow through the fluidic system to the second multiphase flow metering system via the bypass conduits, thereby bypassing the separator, wherein preferably the control system is further configured to implement a medium flow rate dynamic measurement mode when: (i) the controller determines the current operating conditions allow separate flow rate measurements of oil, water, and gas through the system; (ii) the current flow rate is above said threshold amount corresponding to a maximum flow rate capacity of the second multiphase flowmeter; and (iii) the current flow rate is below a second threshold amount corresponding to the maximum flow rate capacity of the first multiphase flowmeter, wherein implementing the medium flow rate dynamic measurement mode comprises operating the valves to direct substantially all fluid flow through the fluidic system to the first multiphase flow metering system via the bypass conduits, thereby bypassing the separator, and/or configured to implement a high flow rate dynamic measurement mode when: (i) the controller determines the current operating conditions allow separate flow rate measurements of oil, water, and gas through the system; and (ii) the current flow rate is above said second threshold amount, wherein implementing the high flow rate dynamic measurement mode comprises operating the valves to direct substantially all fluid flow through the bypass conduits to the first and second multiphase flow metering systems so the first and second multiphase flow metering systems collectively meter all fluid flow through the system, thereby bypassing the separator.

10. System according to any of claims 6 to 9 wherein the control system (161) is further configured to:

30 determine whether or not the current operating conditions allow the first and second multiphase flow metering systems, collectively or individually, to provide separate flow rate measurements of oil, water, and gas being output by the well; and
 route all fluid flow received from the well to the separator when the current operating conditions do not allow separate flow rate measurements of oil, water, and gas by the first and second multiphase flow metering systems, wherein preferably the control system is configured to determine whether or not the current operating conditions allow the first and second multiphase flow metering system, collectively or individually, to provide separate flow rate measurements of oil, water, and gas being output by the well by comparing a current measured gas void fraction of fluid from the well to one or more threshold values corresponding to maximum gas void fractions for which the first and second multiphase flow metering systems are operable to provide separate flow rate measurements of oil, water, and gas being output by the well, and/or
 35 configured to direct fluid from the gas outlet through the gas conduits to one of the first and second multiphase flow metering systems and to direct fluid from the liquid outlet through the liquid conduit to the other of the first and second multiphase flow metering systems so one of the first and second flow metering systems is used to meter separated gas and the other of the first and second flow metering systems is used to meter separated liquid when the control system determines the current operating conditions do not allow the first and second multiphase flow metering systems to provide separate flow rate measurements of oil, water, and gas.

- 40 11. System according to any of claims 6 to 10 wherein the control system (161) is configured to:

50 determine whether or not a set of current operating conditions allows the first and second multiphase flow metering systems, collectively or individually, to provide separate flow rate measurements of oil, water, and gas being output by the well; and
 use one or more of the first and second multiphase flow metering systems to provide separate dynamic flow rate measurements for oil, water, and gas when the controller determines the current operating conditions allow separate flow rate measurements of oil, water, and gas being output by the well.

55 12. System according to any of the preceding claims further comprising a third multiphase flow metering system, wherein the gas leg conduits fluidically couple the gas outlet of the separator to the third multiphase flow metering system, the liquid leg conduits fluidically couple the liquid outlet of the separator to the third multiphase flow metering system, and

the bypass conduits are plumbed to direct multiphase fluid from the petroleum well to the first, second, and third multiphase flow metering systems without flowing the fluid through the separator to thereby bypass the separator, wherein the system preferably further comprises a control system, the control system being configured to use the valves to implement multiple different measurement modes, wherein fluid is routed differently through the fluidic system in each of the modes, and wherein at least three of the measurement modes are dynamic measurement modes in which fluid is routed through the bypass conduits to bypass the separator and allow for measurement of substantially instantaneous individual flow rates for oil, water, and gas by different combinations of the first, second, and third multiphase flow metering systems.

- 5 13. System according to any of the preceding claims further comprising a control system configured to selectively and sequentially route the output one or more wells selected from a group of N wells to the fluidic system to perform a series of well tests on the wells.
- 10 14. Method of testing fluids produced by individual petroleum wells in a group of N petroleum wells, using a system (101) according to any of the preceding claims, the method comprising:
- 15

routing fluid from one or more wells selected for testing to a well test system, the well test system including a separator vessel (107), a plurality of multiphase metering systems (121,123), and a fluidic system (141) for receiving multiphase fluid output from said one or more wells;

20 determining whether or not the plurality of multiphase metering systems can, either individually or collectively, provide individual measurements of oil, water, and gas; and

selectively routing the fluid to the separator vessel when it is determined the plurality of multiphase metering systems cannot provide individual measurements of oil, water, and gas and selectively bypassing the separator to route fluid directly to one or more of the plurality of multiphase metering units when it is determined the multiphase metering units can provide individual measurements of oil, water, and gas.

25

Patentansprüche

- 30 1. System (101) zum Testen der Gewinnung von Fluiden aus einem oder mehreren Erdölbohrlöchern, wobei das System umfasst:
- 35 einen Separator (103), umfassend einen Einlass (105) zum Erhalten einer mehrphasigen Fluidströmung aus einem Erdölbohrloch, ein Gefäß (107) zum Aufnehmen von Fluiden, die durch den Einlass erhalten werden, einen Flüssigkeitsauslass (109) und einen Gasauslass (111), wobei sich der Gasauslass weiter oben am Gefäß als der Flüssigkeitsauslass befindet;
- 40 ein erstes und zweites mehrphasiges Durchflussmesssystem (121,123), wobei das erste und zweite mehrphasige Durchflussmesssystem jeweils in der Lage sind, über mindestens einen Teil seines Anwendungsbereichs die Durchflussmengen für Öl, Wasser und Gas durch das jeweilige Durchflussmesssystem separat zu messen;

gekennzeichnet durch

- 45 ein fluidisches System (141) umfassend: (i) Gasteilabschnittsleitungen (143), die den Gasauslass des Separators an den ersten und zweiten mehrphasigen Durchflussmesser fluidisch koppeln; (ii)
- 50 Flüssigkeitsteilabschnittsleitungen, die den Flüssigkeitsauslass des Separators an das erste und zweite mehrphasige Durchflussmesssystem fluidisch koppeln; (iii) Umgehungsleitungen (147), die so angeschlossen sind, dass das mehrphasige Fluid durch das fluidische System zum ersten und zweiten mehrphasigen Durchflussmesssystem dirigiert wird, ohne dass das Fluid durch den Separator hindurchgeleitet wird, wodurch der Separator umgangen wird; und (iv) eine Mehrzahl von Ventilen (151), die so konfiguriert sind, dass sie ein Leiten des Fluidstroms durch das fluidische System selektiv steuern.
- 55 2. System nach Anspruch 1, wobei die Gasteilabschnittsleitungen (143), Flüssigkeitsteilabschnittsleitungen (145) und Umgehungsleitungen (147) jeweils eine erste Leitung, die so konfiguriert ist, dass Fluid zum ersten mehrphasigen Durchflussmesssystem dirigiert wird, und eine zweite Leitung umfassen, die so konfiguriert ist, dass Fluid zum zweiten mehrphasigen Durchflussmesssystem dirigiert wird, wobei die Mehrzahl der Ventile vorzugsweise ein Ventil für jede der ersten Leitungen und ein Ventil für jede der zweiten Leitungen aufweiset, wobei die Ventile für die erste und zweite Leitung so konfiguriert sind, dass die jeweilige Leitung selektiv geöffnet und geschlossen wird.

3. System nach einem der vorhergehenden Ansprüche, wobei das erste mehrphasige Durchflussmesssystem (121) eine vergleichsweise höhere maximale Durchflussmengenkapazität hat und das zweite mehrphasige Durchflussmesssystem (123) eine vergleichsweise geringere maximale Durchflussmengenkapazität hat.
- 5 4. System nach einem der vorhergehenden Ansprüche, wobei das erste mehrphasige Durchflussmesssystem (121) einen mehrphasigen Coriolis-Durchflussmesser umfasst und/oder das zweite mehrphasige Durchflussmesssystem (123) einen mehrphasigen Coriolis-Durchflussmesser umfasst.
- 10 5. System nach einem der vorhergehenden Ansprüche, wobei das erste und zweite mehrphasige Durchflussmesssystem (121, 123) jeweils einen mehrphasigen Coriolis-Durchflussmesser in Kombination mit einem Messgerät zum Festlegen des Wassergehalts umfasst.
- 15 6. System nach einem der vorhergehenden Ansprüche, weiter umfassend ein Steuersystem (161), wobei das Steuersystem so konfiguriert ist, dass es die Ventile verwendet, um mehrere unterschiedliche Messverfahren auszuführen, wobei das Fluid durch das fluidische System in jedem der Verfahren unterschiedlich geleitet wird.
- 20 7. System nach Anspruch 6, wobei mindestens eines der Messverfahren ein dynamisches Messverfahren ist, bei dem Fluid durch die Umgehungsleitungen geleitet wird, um den Separator zu umgehen, und mindestens eines der anderen Messverfahren ein separates Messverfahren ist, bei dem Fluid zum Trennen in Flüssigkeiten und Gas zum Separator geleitet wird, und dann Flüssigkeiten vom Separator zum einen der ersten und zweiten mehrphasigen Durchflussmesser geleitet wird und Gas vom Separator zum anderen der ersten und zweiten mehrphasigen Durchflussmesser geleitet wird.
- 25 8. System nach Anspruch 6 oder 7, wobei das Steuersystem (161) weiter so konfiguriert ist, dass es:
- festlegt, ob die momentanen Betriebsbedingungen es zulassen oder nicht, dass das erste und zweite mehrphasige Durchflussmesssystem, gemeinsam oder einzeln, separate Durchflussmengenmessungen für Öl, Wasser und Gas durch das System vorsieht; und
- 30 den gesamten Fluidstrom leitet, der vom Bohrloch durch die Umgehungsleitungen erhalten wird, wenn die Steuerung festlegt, dass die momentanen Betriebsbedingungen separate Durchflussmengenmessungen für Öl, Wasser und Gas durch das System zulassen.
- 35 9. System nach Anspruch 8, wobei das erste mehrphasige Durchflussmesssystem (121) eine vergleichsweise höhere maximale Durchflussmengenkapazität hat und das zweite mehrphasige Durchflussmesssystem (123) eine vergleichsweise geringere maximale Durchflussmengenkapazität hat und wobei das Steuersystem (161) weiter so konfiguriert ist, dass es:
- 40 eine momentane Durchflussmenge festlegt, die vom Bohrloch erhalten wird; und
ein dynamisches Messverfahren mit geringer Durchflussmenge ausführt, wenn: (i) die Steuerung festlegt, dass die momentanen Betriebsbedingungen separate Durchflussmengenmessungen für Öl, Wasser und Gas durch das System zulassen; und (ii) die momentane Durchflussmenge unter einer Schwellenmenge liegt, die der maximalen Durchflussmengenkapazität des zweiten mehrphasigen Durchflussmesssystems entspricht, wobei das Ausführen des dynamischen Messverfahrens mit geringer Durchflussmenge das Betätigen der Ventile umfasst, um im Wesentlichen die gesamte Fluidströmung durch das fluidische System zum zweiten mehrphasigen Durchflussmesssystem über die Umgehungsleitungen zu dirigieren, wodurch der Separator umgangen wird, wobei vorzugsweise das Steuersystem weiter so konfiguriert ist, dass ein dynamisches Messverfahren mit mittlerer Durchflussmenge ausgeführt wird, wenn: (i) die Steuerung festlegt, dass die momentanen Betriebsbedingungen separate Durchflussmengenmessungen für Öl, Wasser und Gas durch das System zulassen; (ii) die momentane Durchflussmenge über der Schwellenmenge liegt, die einer maximalen Durchflussmengenkapazität des zweiten mehrphasigen Durchflussmessers entspricht; und (iii) die momentane Durchflussmenge unter einer zweiten Schwellenmenge liegt, die der maximalen Durchflussmengenkapazität des ersten mehrphasigen Durchflussmessers entspricht, wobei das Ausführen des dynamischen Messverfahrens mit mittlerer Durchflussmenge das Betätigen der Ventile umfasst, um im Wesentlichen die gesamte Fluidströmung durch das fluidische System zum ersten mehrphasigen Durchflussmesssystem über die Umgehungsleitungen zu dirigieren, wodurch der Separator umgangen wird, und/oder so konfiguriert ist, dass ein dynamisches Messverfahren mit hoher Durchflussmenge ausgeführt wird, wenn: (i) die Steuerung festlegt, dass die momentanen Betriebsbedingungen separate Durchflussmengenmessungen für Öl, Wasser und Gas durch das System zulassen; und (ii) die momentane Durchflussmenge über der zweiten Schwellenmenge liegt, wobei das Ausführen

des dynamischen Messverfahrens mit hoher Durchflussmenge das Betätigen der Ventile umfasst, um im Wesentlichen die gesamte Fluidströmung durch die Umgehungsleitungen zum ersten und zweiten mehrphasigen Durchflussmesssystem zu dirigieren, so dass das erste und zweite mehrphasige Durchflussmesssystem zusammen die gesamte Fluidströmung durch das System misst, wodurch der Separator umgangen wird.

5

10. System nach einem der Ansprüche 6 bis 9, wobei das Steuersystem (161) weiter so konfiguriert ist, dass es:

festlegt, ob die momentanen Betriebsbedingungen zulassen oder nicht, dass das erste und zweite mehrphasige Durchflussmesssystem, gemeinsam oder einzeln, separate Durchflussmengenmessungen für Öl, Wasser und Gas, die vom Bohrloch abgegeben werden, vorsieht; und
 10 die gesamte Fluidströmung, die vom Bohrloch erhalten wird, zum Separator leitet, wenn die momentanen Betriebsbedingungen keine separaten Durchflussmengenmessungen für Öl, Wasser und Gas durch das erste und zweite mehrphasige Durchflussmesssystem zulassen, wobei vorzugsweise das Steuersystem so konfiguriert ist, dass es festlegt, ob die momentanen Betriebsbedingungen zulassen oder nicht, dass das erste und zweite mehrphasige Durchflussmesssystem, gemeinsam oder einzeln, separate Durchflussmengenmessungen
 15 für Öl, Wasser und Gas, die vom Bohrloch abgegeben werden, vorsieht, indem ein momentaner gemessener Gasblosenanteil des Fluids aus dem Bohrloch mit einem oder mehreren Schwellenwerten verglichen wird, die den maximalen Gasblosenanteilen entsprechen, für die das erste und zweite mehrphasige Durchflussmesssystem funktionsbereit ist, um separate Durchflussmengenmessungen für Öl, Wasser und Gas, die vom Bohrloch abgegeben werden, vorzusehen, und/oder so konfiguriert ist, dass es Fluid vom Gasauslass durch die
 20 Gasleitungen zum einem der ersten und zweiten mehrphasigen Durchflussmesssysteme dirigiert und Fluid vom Flüssigkeitsauslass durch die Flüssigkeitseleitung zum anderen der ersten und zweiten Durchflussmesssysteme dirigiert, so dass das eine der ersten und zweiten mehrphasigen Durchflussmesssysteme verwendet wird, um
 25 separiertes Gas zu messen, und das andere der ersten und zweiten Durchflussmesssysteme verwendet wird, um separierte Flüssigkeit zu messen, wenn das Steuersystem festlegt, dass die momentanen Betriebsbedingungen es nicht zulassen, dass das erste und zweite mehrphasige Durchflussmesssystem separate Durchflussmengenmessungen für Öl, Wasser und Gas vorsieht.

11. System nach einem der Ansprüche 6 bis 10, wobei das Steuersystem (161) so konfiguriert ist, dass es:

30

festlegt, ob ein Satz von momentanen Betriebsbedingungen es zulässt oder nicht, dass das erste und zweite mehrphasige Durchflussmesssystem, gemeinsam oder einzeln, separate Durchflussmengenmessungen für Öl, Wasser und Gas, die vom Bohrloch abgegeben werden, vorsieht; und
 eines oder mehrere der ersten und zweiten mehrphasigen Durchflussmesssysteme verwendet, um separate
 35 dynamische Durchflussmengenmessungen für Öl, Wasser und Gas vorzusehen, wenn die Steuerung festlegt, dass die momentanen Betriebsbedingungen separate Durchflussmengenmessungen für Öl, Wasser und Gas, die vom Bohrloch abgegeben werden, zulassen.

12. System nach einem der vorhergehenden Ansprüche, weiter umfassend ein drittes mehrphasiges Durchflussmess-

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system, wobei die Gasteilabschnittsleitungen den Gasauslass des Separators an das dritte mehrphasige Durchflussmesssystem fluidisch koppeln, wobei die Flüssigkeitsteilabschnittsleitungen den Flüssigkeitsauslass des Separators an das dritte mehrphasige Durchflussmesssystem fluidisch koppeln, und die Umgehungsleitungen ange-
 45 schlossen sind, um mehrphasiges Fluid vom Erdölbohrloch zum ersten zweiten und dritten mehrphasigen Durchflussmesssystem zu dirigieren, ohne das Fluid durch den Separator hindurchzuleiten, wodurch der Separator um-
 50 gangen wird,

wobei das System vorzugsweise weiter ein Steuersystem umfasst, wobei das Steuersystem so konfiguriert ist, dass es die Ventile verwendet, um mehrere unterschiedliche Messverfahren auszuführen, wobei Fluid in jedem der Verfahren unterschiedlich durch das fluidische System geleitet wird, und wobei mindestens drei der Messverfahren dynamische Messverfahren sind, bei denen Fluid durch die Umgehungsleitungen geleitet werden, um den Separator zu umgehen und eine Messung von im Wesentlichen augenblicklichen einzelnen Durchflussmengen für Öl, Wasser und Gas durch unterschiedliche Kombinationen der ersten, zweiten und dritten mehrphasigen Durchflussmesssys-
 teme zuzulassen.

13. System nach einem der vorhergehenden Ansprüche, weiter umfassend ein Steuersystem, das so konfiguriert ist,

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dass es selektiv und fortlaufend die Fördermenge von einem oder mehreren Bohrlöchern, die aus einer Gruppe von N Bohrlöchern ausgewählt sind, zum fluidischen System leitet, um eine Reihe von Bohrlochtests bei den Bohrlöchern durchzuführen.

14. Verfahren zum Testen von Fluiden, die aus individuellen Rohölbohrlöchern in einer Gruppe von N-Rohölbohrlöchern gewonnen werden, und zwar mittels eines Systems (101) nach einem der vorhergehenden Ansprüche, wobei das Verfahren umfasst:

- 5 Leiten von Fluid aus einem oder mehreren Bohrlöchern, die zum Testen ausgewählt werden, zu einem Bohrlochtestsystem, wobei das Bohrlochtestsystem ein Separatorgefäß (107), eine Mehrzahl von mehrphasigen Messsystemen (121, 123) und ein fluidisches System (141) zum Erhalten einer mehrphasigen Fluidfördermenge aus dem einen oder den mehreren Bohrlöchern aufweist;
- 10 Festlegen, ob die Mehrzahl der mehrphasigen Messsysteme entweder einzeln oder gemeinsam individuelle Messungen für Öl, Wasser und Gas vorsehen kann oder nicht; und selektives Leiten des Fluids zum Separatorgefäß, wenn festgelegt wird, dass die Mehrzahl der mehrphasigen Messsysteme keine individuellen Messungen für Öl, Wasser und Gas vorsehen kann, und selektives Umgehen des Separators, um Fluid direkt zu einer der mehreren aus der Mehrzahl der mehrphasigen Messeinheiten zu leiten, wenn festgelegt wird, dass die mehrphasigen Messeinheiten individuelle Messungen für Öl, Wasser und Gas vorsehen können.
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Revendications

- 20 1. Système (101) pour tester la production de fluides par un ou plusieurs puits de pétrole, le système comprenant :
un séparateur (103) comprenant une entrée (105) pour recevoir un flux de fluide multiphasé depuis un puits de pétrole, un récipient (107) pour contenir des fluides reçus via l'entrée, une sortie de liquide (109), et une sortie de gaz (111),
la sortie de gaz étant positionnée à une hauteur plus élevée sur le récipient que la sortie de liquide ;
un premier et un second système de dosage de mesure de débit multiphasé (121, 123), chacun du premier et du second système de mesure de débit multiphasé ayant la capacité, sur au moins une portion de son enveloppe de fonctionnement, de mesurer séparément des débits de pétrole, d'eau et de gaz via le système de mesure de débit respectif ;
30 caractérisé par
un système fluidique (141) comprenant : (i) des conduits ramifiés de gaz (143) qui couplent sur le plan fluidique la sortie de gaz du séparateur au premier et au second dispositif de mesure de débit multiphasé ; (ii) des conduits ramifiés de liquide qui couplent sur le plan fluidique la sortie de liquide du séparateur au premier et au second système de mesure de débit multiphasé ; (iii) des conduits de by-pass (147) branchés pour diriger le fluide multiphasé à travers le système fluidique vers le premier et le second système de mesure de débit multiphasé sans laisser le fluide s'écouler à travers le séparateur pour bypasser ainsi le séparateur ; et (iv) une pluralité de valves (151) configurées pour commander sélectivement le trajet du flux de fluide à travers le système fluidique.
- 40 2. Système selon la revendication 1, dans lequel les conduits ramifiés de gaz (143), les conduits ramifiés de liquide (145), et les conduits de by-pass (147) comprennent un premier conduit configuré pour diriger le fluide vers le premier système de mesure de débit multiphasé, et un second conduit configuré pour diriger le fluide vers le second système de dosage de débit multiphasé, dans lequel ladite pluralité de valves incluent de préférence une valve pour chacun des premiers conduits et une valve pour chacun des seconds conduits, les valves pour les premiers et les seconds conduits étant configurées pour ouvrir et fermer sélectivement le conduit respectif.
- 45 3. Système selon l'une quelconque des revendications précédentes, dans lequel le premier système de mesure de débit multiphasé (121) possède une capacité de débit maximum relativement plus élevée et le second système de mesure de débit multiphasé (123) possède une capacité de débit maximum relativement plus faible.
- 50 4. Système selon l'une quelconque des revendications précédentes, dans lequel le premier système de mesure de débit multiphasé (121) comprend un débitmètre de Coriolis multiphasé et/ou le second système de mesure de débit multiphasé comprend un débitmètre de Coriolis multiphasé.
- 55 5. Système selon l'une quelconque des revendications précédentes, dans lequel chacun du premier et du second système de mesure de débit multiphasé (121, 123) comprend un débitmètre de Coriolis multiphasé en combinaison avec un compteur d'eau.

6. Système selon l'une quelconque des revendications précédentes, comprenant en outre un système de commande (161), le système de commande étant configuré pour utiliser les valves afin de mettre en oeuvre une multiplicité de mode de mesures différents, dans lesquels le fluide est mené sur des trajets différents à travers le système fluidique dans chacun des modes.
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7. Système selon la revendication 6, dans lequel l'un au moins des modes de mesure est un mode de mesure dynamique dans lequel le fluide est amené sur un trajet via les conduits de by-pass afin de bypasser le séparateur, et l'un au moins des autres modes de mesure est un mode de mesure séparé dans lequel le fluide est amené sur un trajet vers le séparateur pour une séparation en liquides et en gaz puis les liquides sont amenés sur un trajet depuis le séparateur vers l'un du premier et du second système de mesure de débit multiphasé et le gaz est amené sur un trajet depuis le séparateur vers l'autre du premier et du second système de mesure de débit multiphasé.
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8. Système selon la revendication 6 ou 7, dans lequel le système de commande (161) est en outre configuré pour :
- 15 déterminer si les conditions de fonctionnement actuelles permettent ou non au premier et au second système de mesure de débit multiphasé, collectivement ou individuellement, de fournir des mesures de débit séparées de pétrole, d'eau et de gaz à travers le système ; et
mener tout le flux de fluide reçu depuis le puits sur un trajet à travers les conduits de by-pass quand le contrôleur détermine que les conditions de fonctionnement actuelles permettent des mesures de débit séparées de pétrole, d'eau et de gaz à travers le système.
- 20
9. Système selon la revendication 8, dans lequel le premier système de mesure de débit multiphasé (121) possède une capacité de débit maximum relativement plus élevée et le second système de mesure de débit multiphasé possède une capacité de débit maximum relativement plus faible, et dans lequel le système de commande (161) est en outre configuré pour :
- 25 déterminer un débit actuel reçu depuis le puits ; et
mettre en oeuvre un mode de mesure dynamique à faible débit quand : (i) le contrôleur détermine que les conditions de fonctionnement actuelles permettent des mesures de débit séparées de pétrole, d'eau et de gaz à travers le système ; et (ii) le débit actuel est au-dessous d'un seuil correspondant à la capacité de débit maximum du second système de mesure de débit multiphasé, dans lequel la mise en oeuvre du mode de mesure dynamique à faible débit comprend de faire fonctionner les valves afin de diriger sensiblement tout le flux de fluide à travers le système fluidique vers le second système de mesure de débit multiphasé via les conduits de by-pass, en bypassant ainsi le séparateur, dans lequel de préférence le système de commande est en outre configuré pour mettre en oeuvre un mode de mesure dynamique à débit moyen quand : (i) le contrôleur détermine que les conditions de fonctionnement actuelles permettent des mesures de débit séparées de pétrole, d'eau et de gaz à travers le système ; (ii) le débit actuel est au-dessus dudit seuil correspondant à une capacité de débit maximum du second système de mesure de débit multiphasé ; et (ii) le débit actuel est au-dessous d'un second seuil correspondant à la capacité de débit maximum du premier système de mesure de débit multiphasé, dans lequel la mise en oeuvre du mode de mesure dynamique à débit maximum comprend de faire fonctionner les valves pour diriger sensiblement tout le flux de fluide à travers le système fluidique vers le premier système de mesure de débit multiphasé via les conduits de by-pass, en bypassant ainsi le séparateur, et/ou est configuré pour mettre en oeuvre un mode de mesure dynamique à débit élevé quand : (i) le contrôleur détermine que les conditions de fonctionnement actuelles permettent des mesures de débit séparées de pétrole, d'eau et de gaz à travers le système ; et (ii) le débit actuel est au-dessus dudit second seuil, dans lequel la mise en oeuvre du mode de mesure dynamique à débit élevé comprend de faire fonctionner les valves afin de diriger sensiblement la totalité du flux de fluide à travers les conduits de by-pass vers le premier et le second système de mesure de débit multiphasé de sorte que le premier et le second système de mesure de débit multiphasé mesurent collectivement tout le flux de fluide à travers le système, en bypassant ainsi le séparateur.
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10. Système selon l'une quelconque des revendications 6 à 9, dans lequel le système de commande (161) est en outre configuré pour :
- 55 déterminer si les conditions de fonctionnement actuelles permettent ou non au premier et au second système de mesure de débit multiphasé, collectivement ou individuellement, de fournir des mesures de débit séparées de pétrole, d'eau et de gaz qui sont fournis par le puits ; et
mener tout le flux de fluide reçu depuis le puits sur un trajet vers le séparateur quand les conditions de fonctionnement actuelles ne permettent pas des mesures de débit séparées de pétrole, d'eau et de gaz par le

5 premier et le second système de mesure de débit multiphasé,
dans lequel de préférence le système de commande est configuré pour déterminer si les conditions de fonctionnement actuelles permettent ou non au premier et au second système de mesure de débit multiphasé, collectivement ou individuellement, de fournir des mesures de débit séparées de pétrole, d'eau et de gaz qui sont fournis par le puits en comparant une fraction de fluide exempte de gaz actuellement mesurée provenant du puits à une ou plusieurs valeurs seuil correspondant à des fractions exemptes de gaz maximum pour lesquelles le premier et le second système de mesure de débit multiphasé sont capables de fonctionner pour fournir des mesures de débit séparées de pétrole, d'eau et de gaz qui sont fournis par le puits, et/ou
10 configuré pour diriger le fluide provenant de la sortie de gaz via les conduits de gaz vers l'un du premier et du second système de mesure de débit multiphasé et pour diriger le fluide provenant de la sortie de liquide via le conduit de liquide vers l'autre du premier et du second système de mesure de débit multiphasé, de sorte que l'un du premier et du second système de mesure de débit est utilisé pour mesurer le gaz séparé et l'autre du premier et du second système de mesure de débit est utilisé pour mesurer le liquide séparé quand le système de commande détermine que les conditions de fonctionnement actuelles ne permettent pas au premier et au second système de mesure de débit multiphasé de fournir des mesures de débit séparées de pétrole, d'eau et de gaz.

15 11. Système selon l'une quelconque des revendications 6 à 10, dans lequel le système de commande (161) est configuré pour :

20 déterminer si un groupe de conditions de fonctionnement actuelles permet ou non au premier et au second système de mesure de débit multiphasé, collectivement ou individuellement, de fournir des mesures de débit séparées de pétrole, d'eau et de gaz qui sont fournis par le puits ; et
25 utiliser un ou plusieurs du premier et du second système de mesure de débit multiphasé pour fournir des mesures de débit dynamique séparées pour le pétrole, l'eau et le gaz quand le contrôleur détermine que les conditions de fonctionnement actuel permettent des mesures de débit séparées de pétrole, d'eau et de gaz qui sont fournis par le puits.

30 12. Système selon l'une quelconque des revendications précédentes, comprenant en outre un troisième système de mesure de débit multiphasé, dans lequel les conduits ramifiés de gaz couplent sur le plan fluidique la sortie de gaz du séparateur au troisième système de mesure de débit multiphasé, les conduits ramifiés de liquide couplent sur le plan fluidique la sortie de liquide du séparateur au troisième système de mesure de débit multiphasé, et les conduits de by-pass sont branchés pour diriger le fluide multiphasé provenant du puits de pétrole vers le premier, le second et le troisième système de mesure de débit multiphasé sans laisser le fluide s'écouler à travers le séparateur

35 pour bypasser ainsi le séparateur,
dans lequel le système comprend en outre de préférence un système de commande, le système de commande étant configuré pour utiliser les valves afin de mettre en oeuvre une multiplicité de modes de mesure différents, dans lesquels le fluide est mené sur des trajets différents à travers le système fluidique dans chacun des modes, et dans lesquels au moins trois des modes de mesure sont des modes de mesure dynamiques dans lesquels le fluide est mené sur un trajet à travers les conduits de by-pass pour bypasser le séparateur et permettre la mesure sensiblement instantanée de débits individuels pour le pétrole, l'eau et le gaz par différentes combinaisons du premier, du second et du troisième système de mesure de débit multiphasé.

40 13. Système selon l'une quelconque des revendications précédentes, comprenant en outre un système de commande configuré pour mener sélectivement et séquentiellement la sortie d'un ou plusieurs puits sélectionnés parmi un groupe de N puits sur un trajet vers le système fluidique pour exécuter une série de tests sur les puits.

45 14. Procédé pour tester des fluides produits par des puits de pétrole individuel dans un groupe de N puits de pétrole, en utilisant un système (101) selon l'une quelconque des revendications précédentes, le procédé comprenant les étapes consistant à :

50 mener le fluide provenant d'un ou plusieurs puits sélectionnés pour le test sur un trajet vers un système de test de puits, le système de test de puits incluant un récipient séparateur (107), une pluralité de systèmes de mesure de débit multiphasé (121, 123), et un système fluidique (141) pour recevoir un fluide multiphasé fourni depuis lesdits un ou plusieurs puits ;

55 déterminer si la pluralité de systèmes de mesure multiphasé peuvent ou non, soit individuellement soit collectivement, fournir des mesures individuelles de pétrole, d'eau et de gaz ; et

mener sélectivement le fluide sur un trajet vers le récipient séparateur lorsque l'on détermine que la pluralité

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de systèmes de mesure multiphasé ne peuvent pas fournir des mesures individuelles de pétrole, d'eau et de gaz, et bypasser sélectivement le séparateur pour mener le fluide sur un trajet direct vers une ou plusieurs des unités de mesure multiphasé lorsqu'on détermine que les unités de mesure multiphasé peuvent fournir des mesures individuelles de pétrole, d'eau et de gaz.

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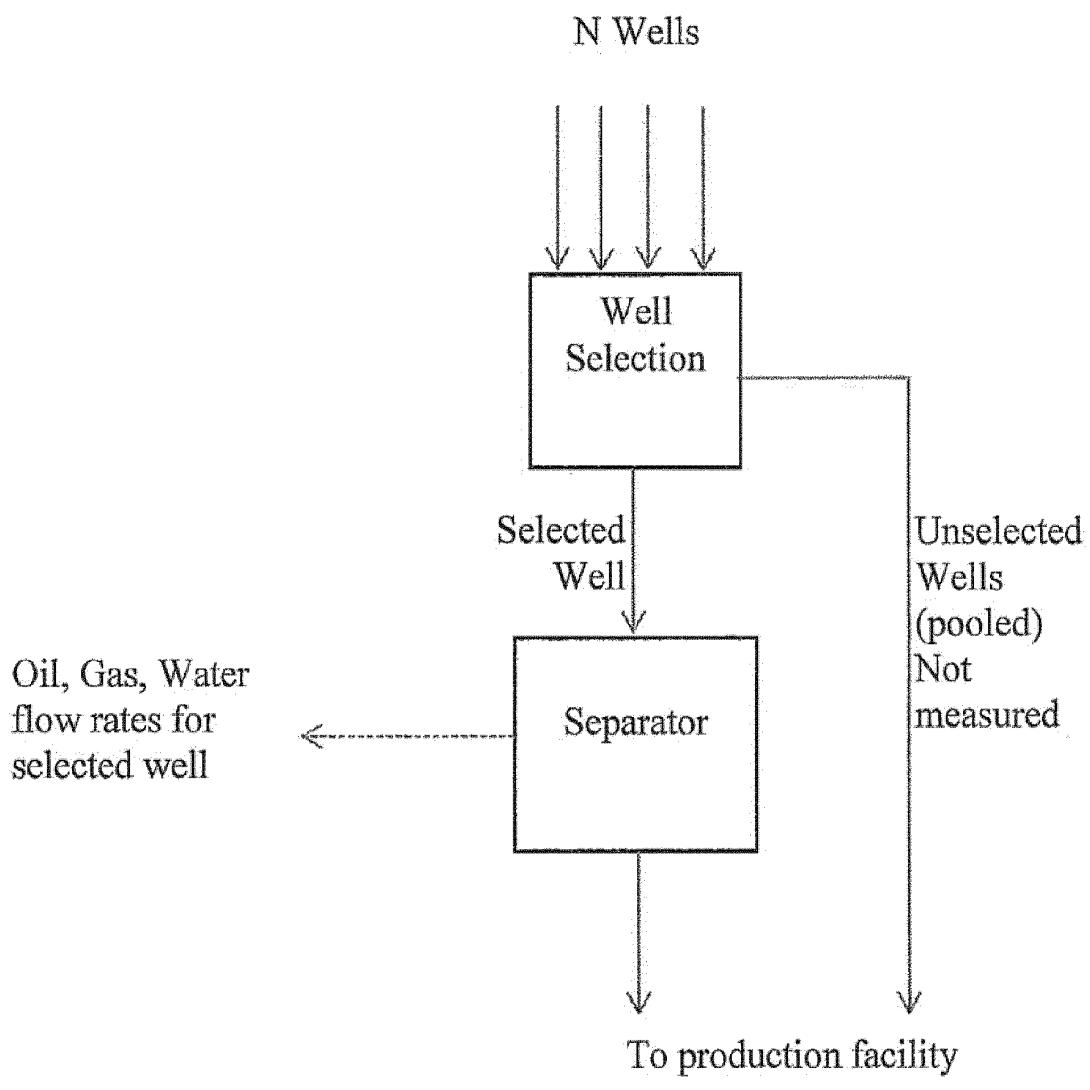
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FIG. 1



(Prior Art)

FIG. 2

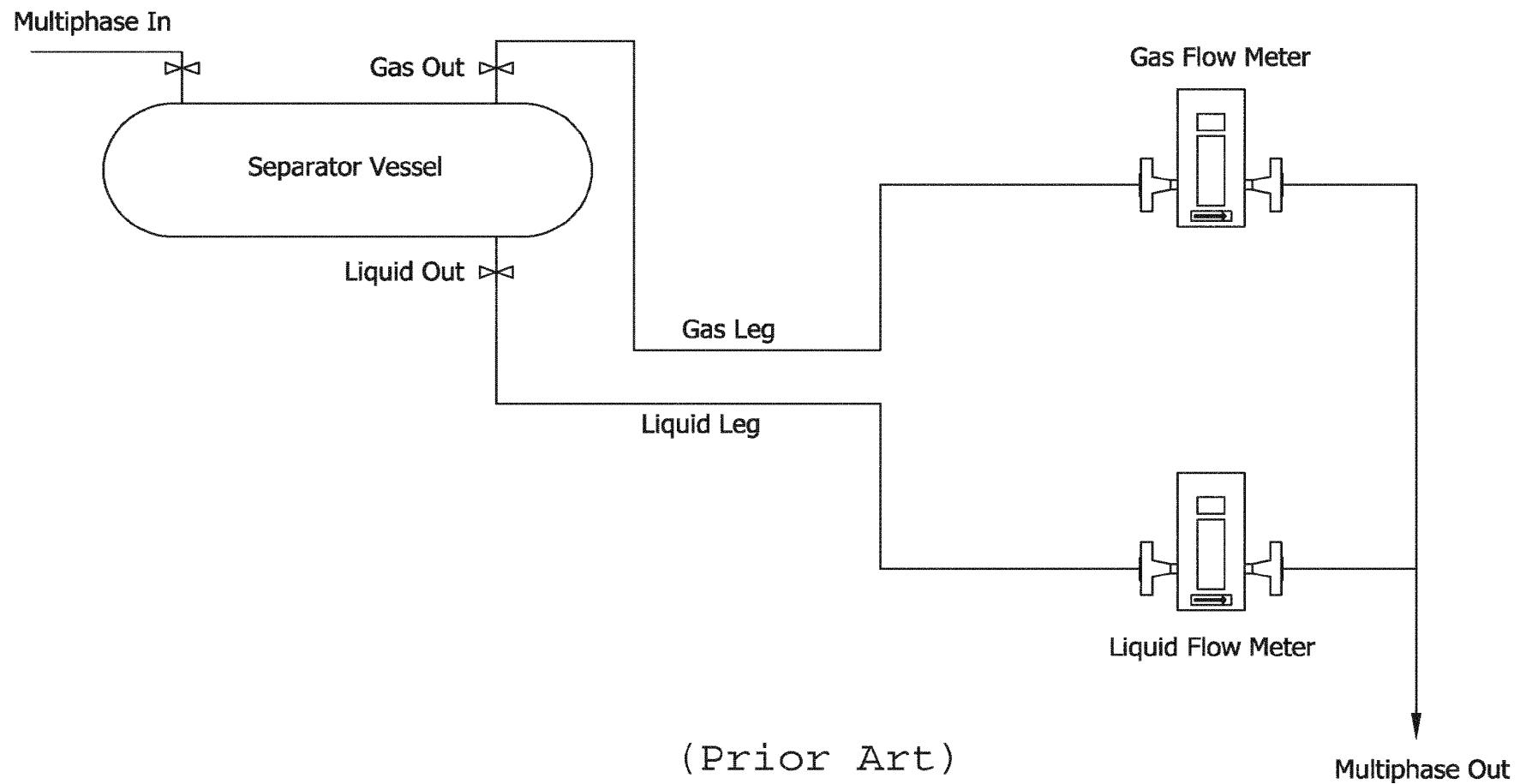


FIG. 3

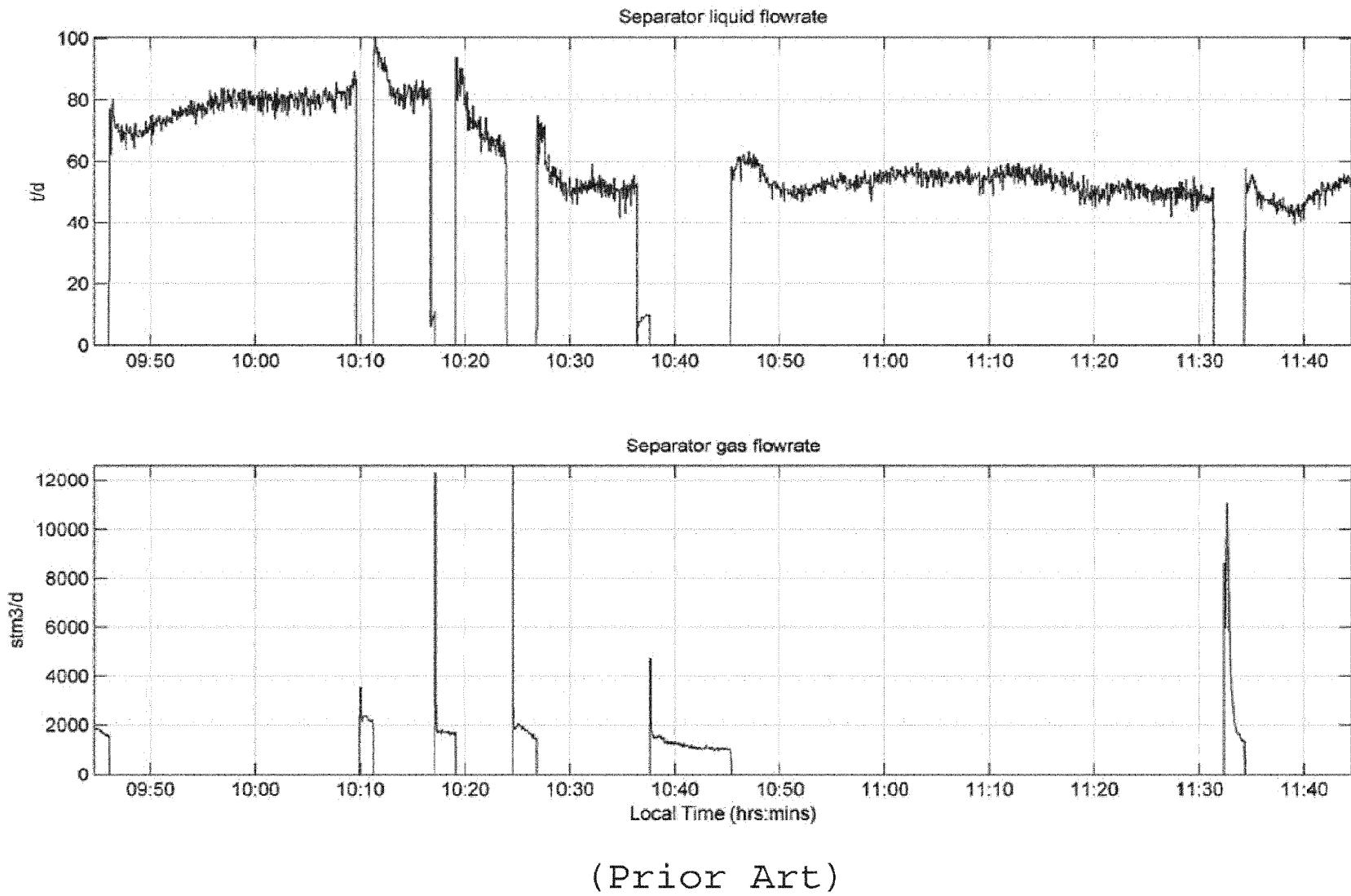
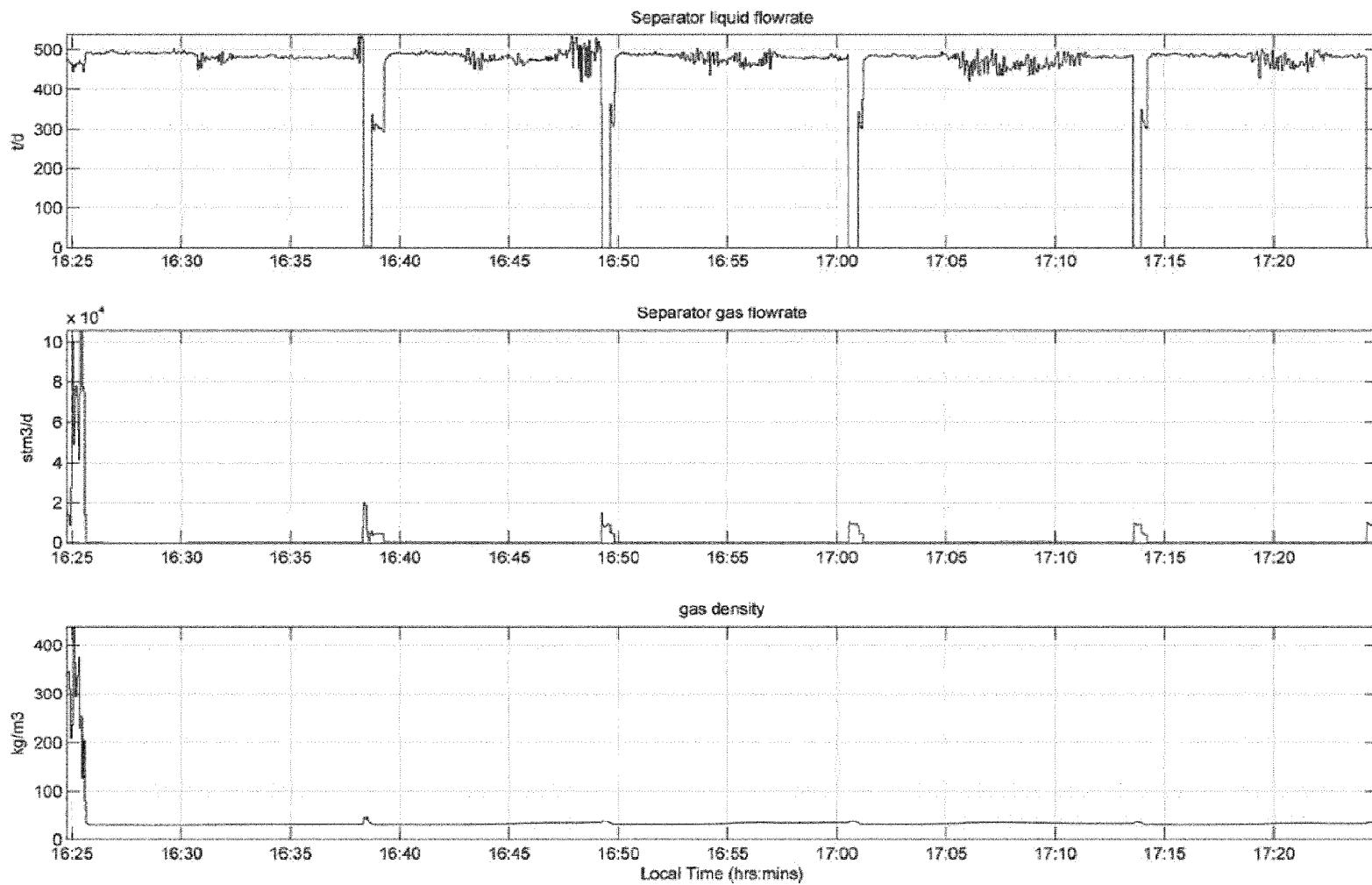


FIG. 4



(Prior Art)

FIG. 7

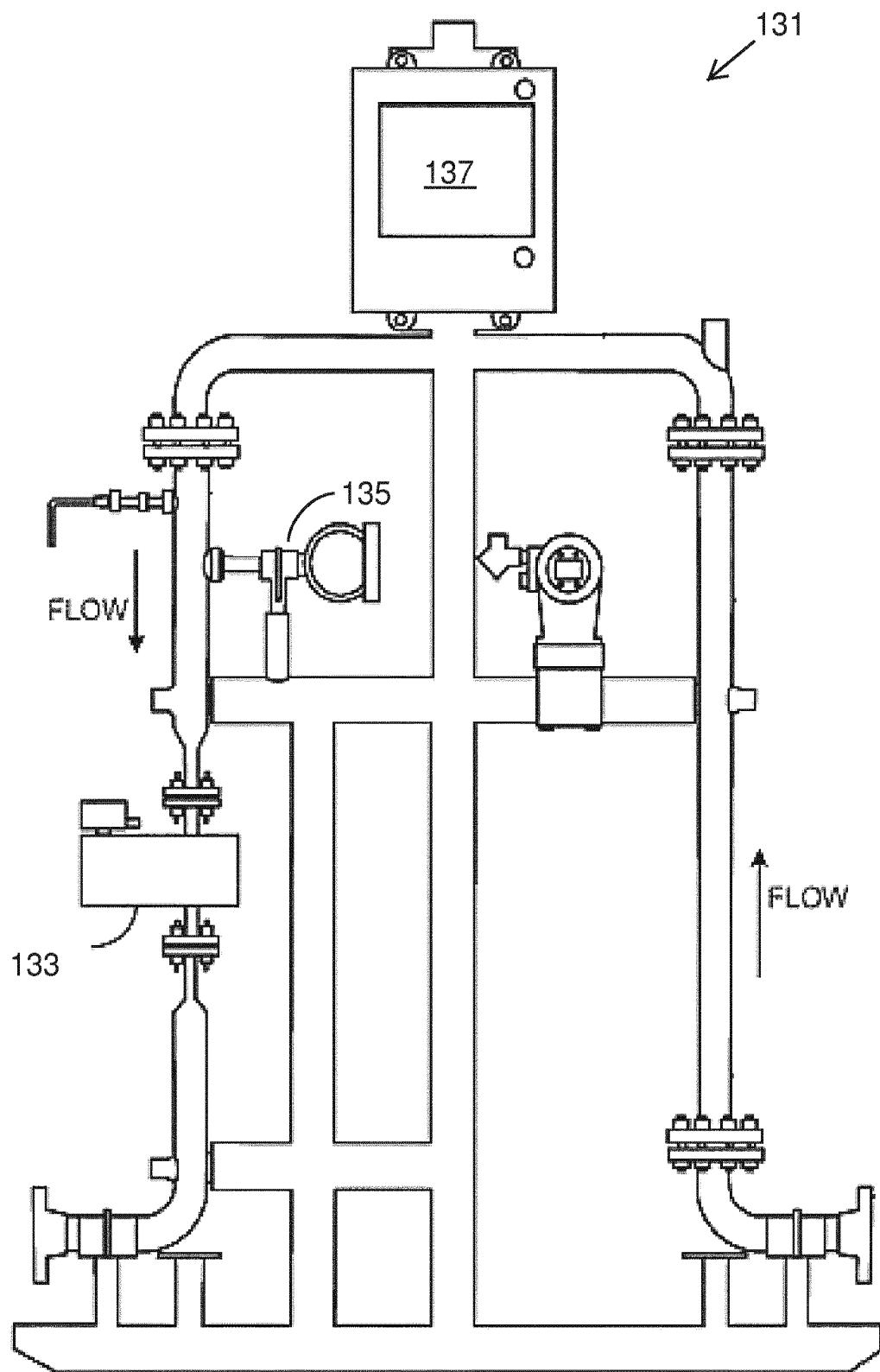


FIG. 8

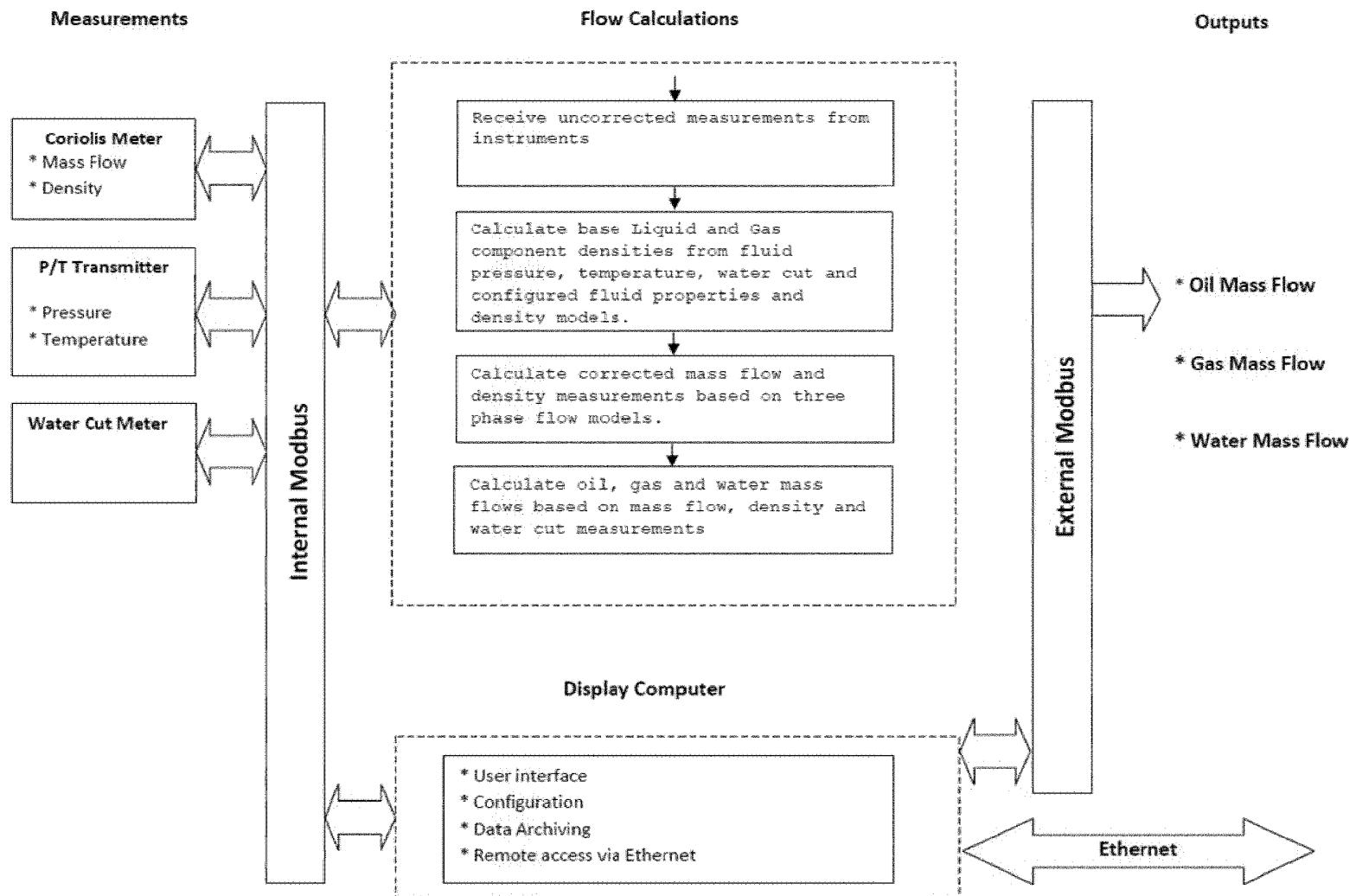
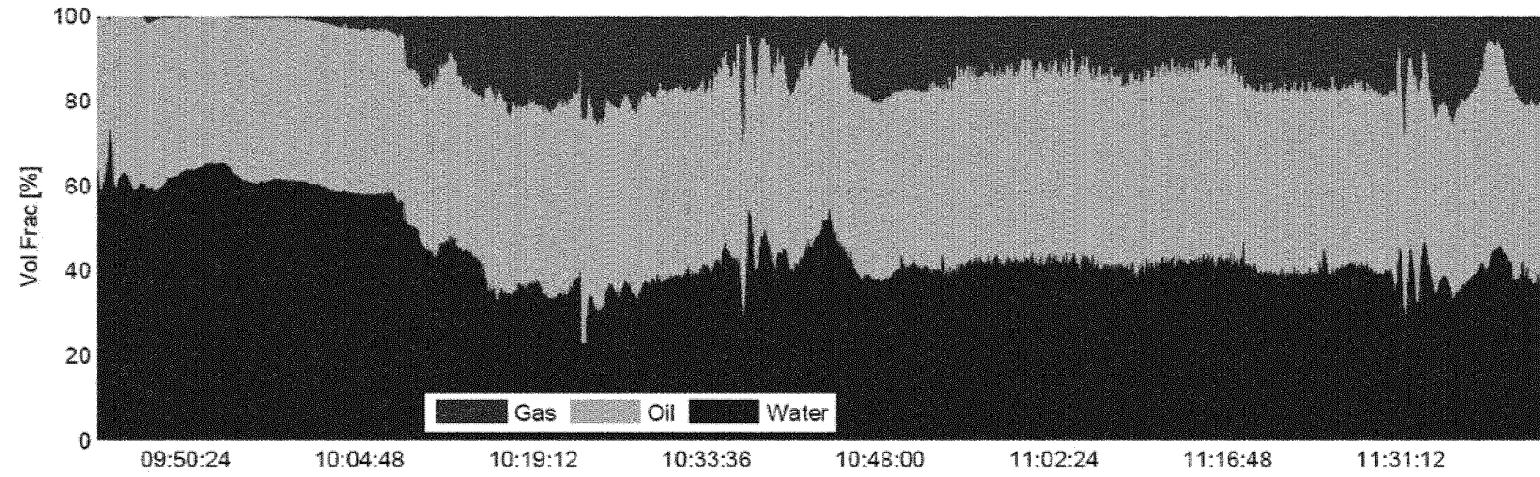


FIG. 9



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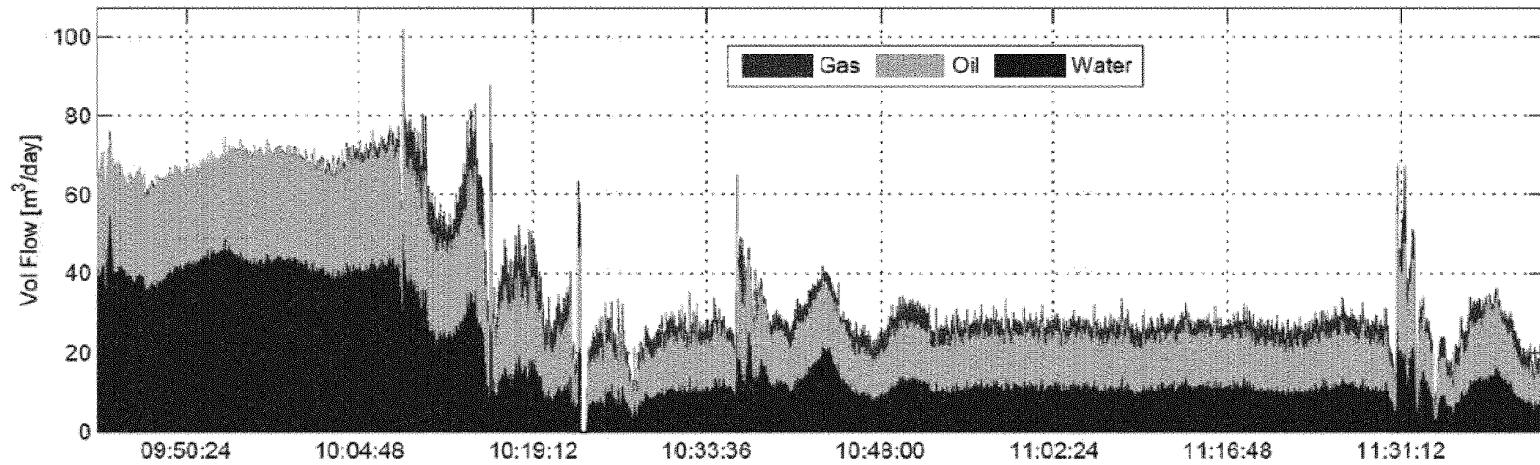


FIG. 5

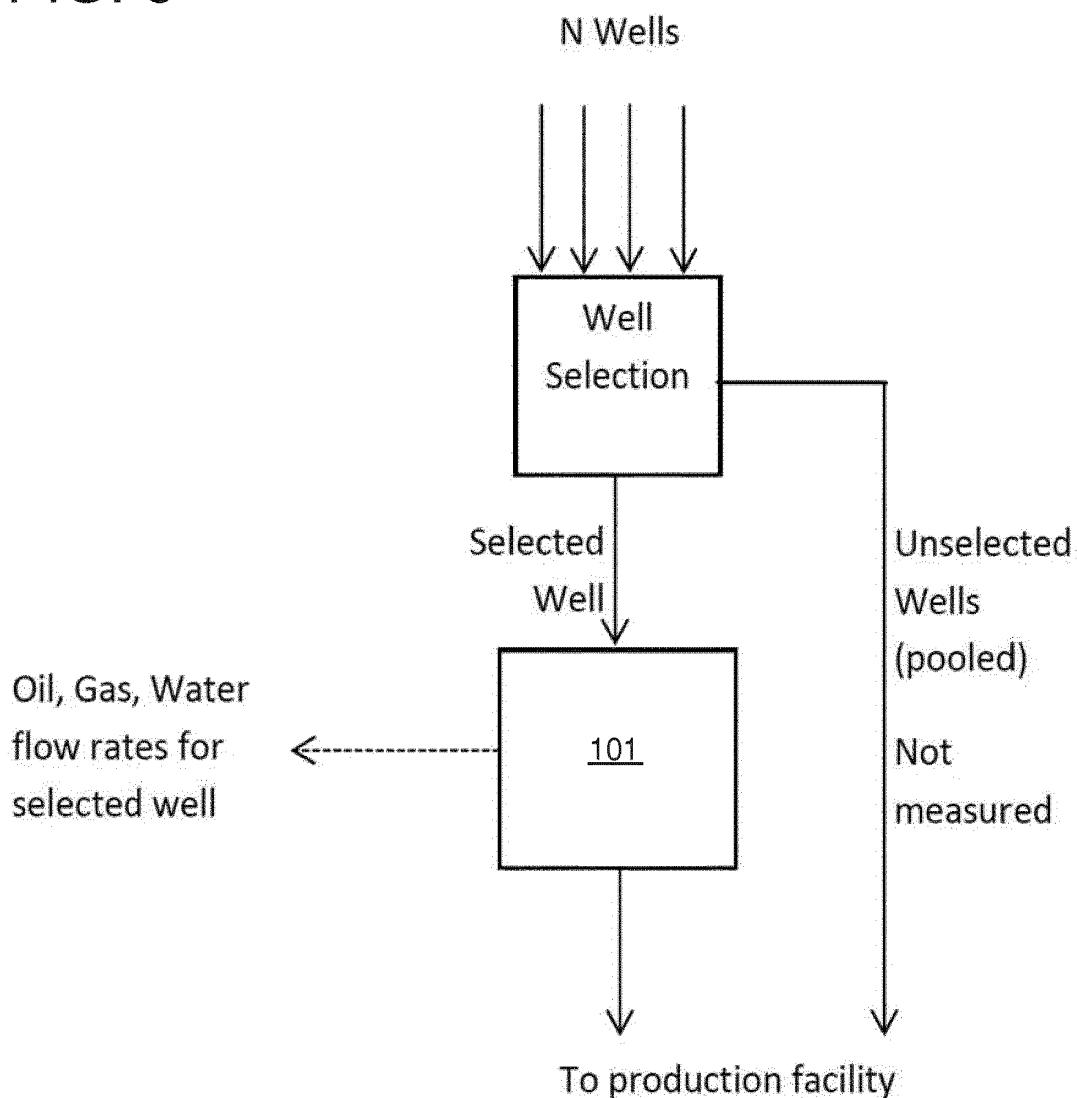


FIG. 6

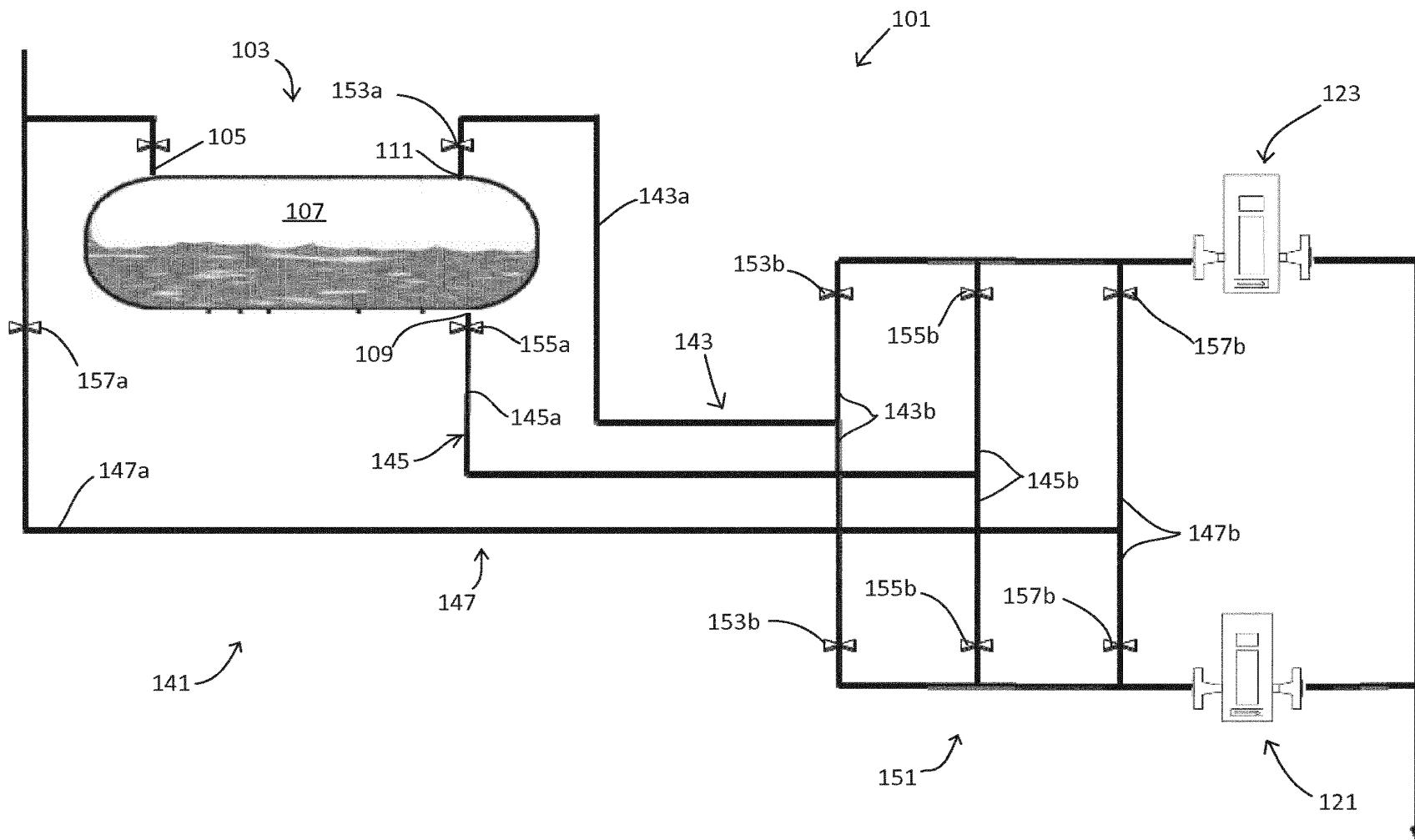
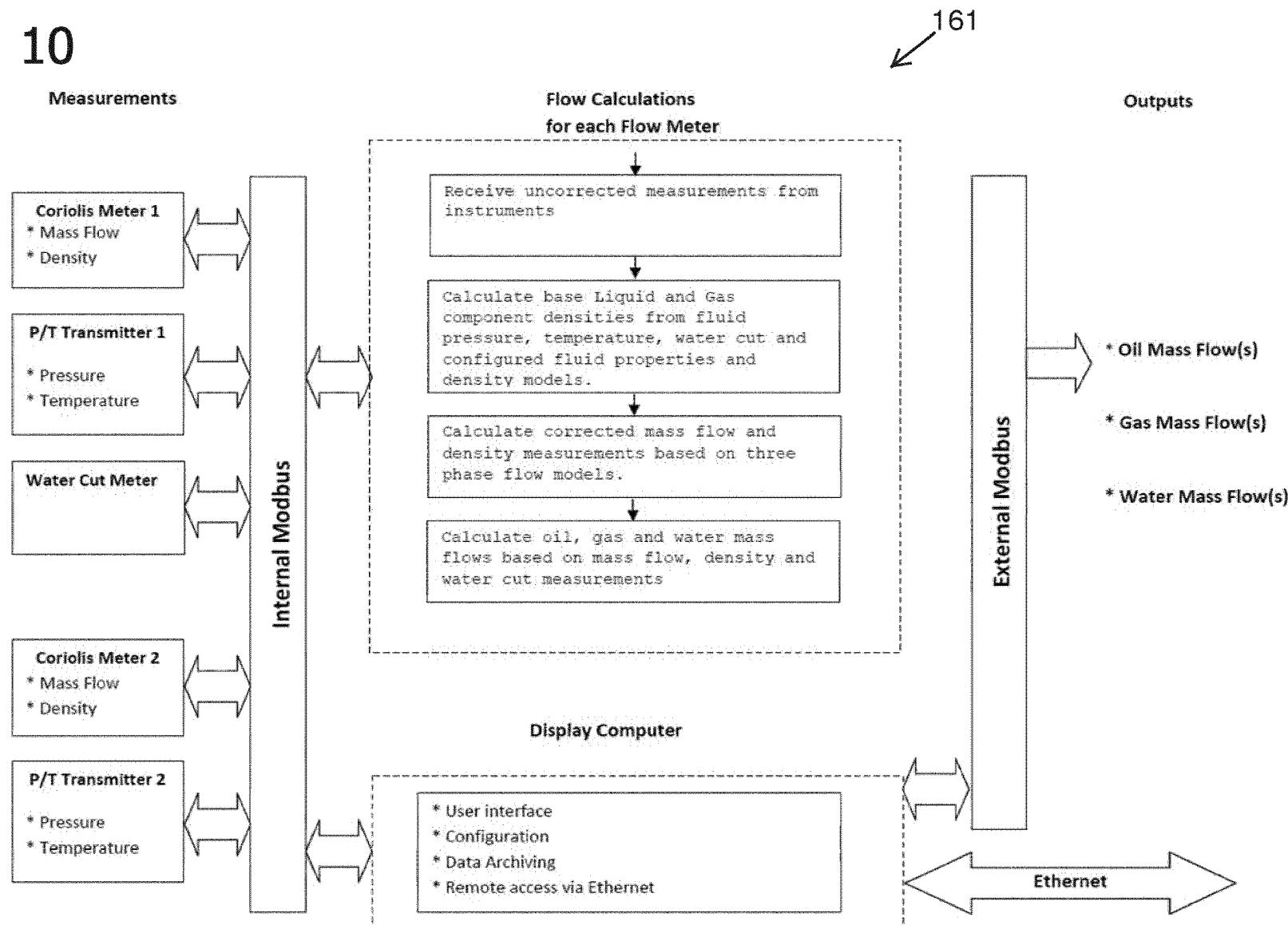


FIG. 10



REFERENCES CITED IN THE DESCRIPTION

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