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(54) **Title:** SYSTEM AND METHOD FOR DETERMINING PRODUCTION FROM A PLURALITY OF WELLS

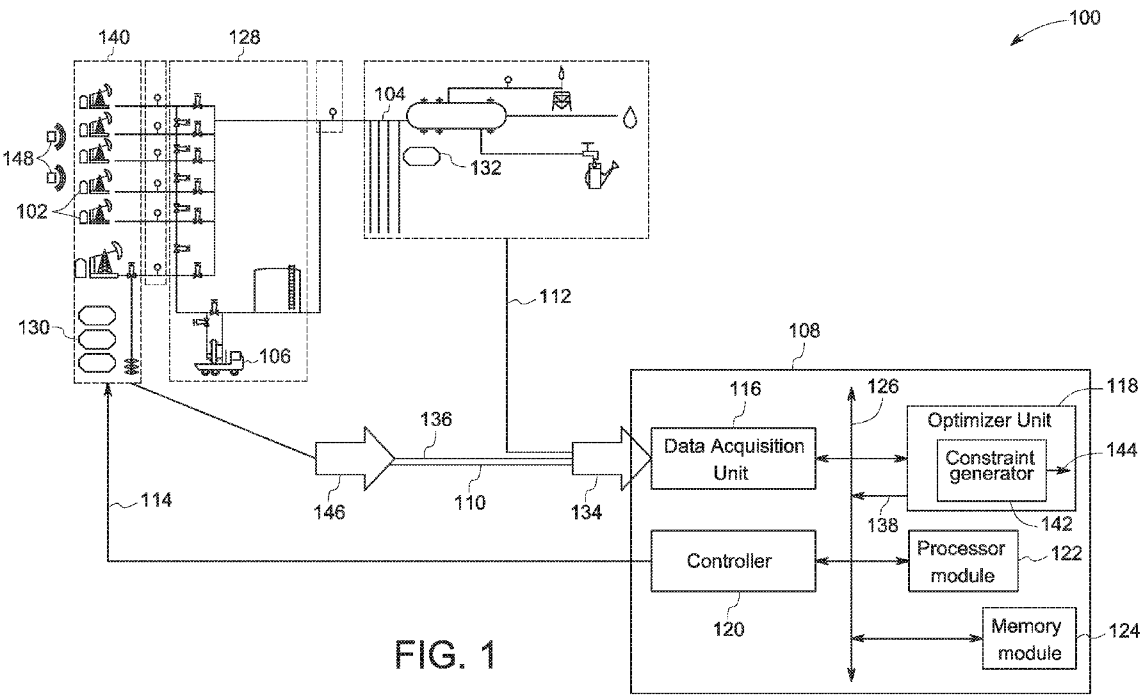

FIG. 1

(57) **Abstract:** A method includes receiving field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells. The field measurement data are representative of speed data and run-time data, of the plurality of well-pumps. The method further includes receiving commingled-flow measurement data. The commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells. The method further includes determining, by an optimizer unit, well-flow data of the plurality of wells based on the commingled-flow measurement data, the field measurement data, and a plurality of conservation constraints generated by a constraint generator. The well-flow data are representative of fluid flow data, from each of the plurality of wells. The method also includes controlling operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells.

WO 2019/060227 A1

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SYSTEM AND METHOD FOR DETERMINING PRODUCTION FROM A PLURALITY OF WELLS

BACKGROUND

[0001] Embodiments of the present invention relate generally to production in an oil field, and more particularly to a system and a method for determining fluid flow estimates of individual wells based on a measurement of commingled flow at a pool-line.

[0002] Produced fluid from wells may include various quantities of crude oil, natural gas and/or water, depending on the specific conditions of reservoir. The amount and rate at which fluid is extracted from a well depends on condition of the reservoir such as a pressure difference between the reservoir and a wellbore. The wellbore pressure may be adjusted by various devices such as pumps, compressors, fluid injection devices the like.

[0003] Various devices may be used to separate oil and water from gas in the produced fluid. The surface devices are designed to process selected volume or quantity of the produced fluid. The selected volume depends on volumes of production from various wellbores and number of wellbores coupled to surface devices. An objective of the surface devices is to optimize the economic performance of the reservoir. Specifically, throughput of the reservoir is to be managed by the surface devices by varying production rates from the plurality of wells.

[0004] Expected quantity of produced fluid from each wellbore is determined by modeling the performance of each well and simulating reservoir performance in real time to identify actions that are required to control the operation of the surface devices. However, such simulations may not provide feasible solutions for specified production constraints. Another issue is that the feasible solutions provided by the simulations may not be practical for implementation.

BRIEF DESCRIPTION

[0005] In accordance with one aspect of the present invention, a method is disclosed. The method includes receiving field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells from a plurality of pump-off controller (POC) sensors. The field measurement data are representative of speed data and run-time data of the plurality of well-pumps. The method further includes receiving commingled-flow measurement data using a plurality of commingled-flow measurement sensors. The commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells. The method further includes determining, by an optimizer unit, well-flow data of the plurality of wells based on the commingled-flow measurement data, the field measurement data, and a plurality of conservation constraints generated by a constraint generator. The well-flow data are representative of fluid flow data from each of the plurality of wells. The method also includes controlling operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells.

[0006] In accordance with another aspect of the present invention, a system is disclosed. The system includes a plurality of sensors disposed in an oil field. The plurality of sensors includes a plurality of pump-off controller (POC) sensors disposed on a plurality of well-pumps and a plurality of commingled-flow measurement sensors disposed on a pool-line. The system further includes a data acquisition unit configured to receive field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells from the plurality of POC sensors. The field measurement data are representative of speed data and run-time data of the plurality of well-pumps. The data acquisition unit is further configured to receive commingled-flow measurement data using the plurality of commingled-flow measurement sensors. The commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells. The system also includes an optimizer unit communicatively coupled to the data acquisition unit and configured to generate a plurality of conservation constraints using a constraint generator, based on the commingled-flow measurement data and the field measurement data. The optimizer is further configured to determine well-flow data corresponding to the plurality of wells based on the commingled-flow measurement data, the field measurement data, and the plurality of conservation constraints. The well-flow data are representative of fluid flow data from each of the plurality of wells. The system also includes a controller communicatively coupled to the data acquisition unit and the optimizer unit and configured to control operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells.

[0007] In accordance with another aspect of the present invention, a non-transitory computer readable medium having instructions to enable at least one processor module is disclosed. The instructions enable the at least one processor module to receive field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells from a plurality of pump-off controller (POC) sensors. The field measurement data are representative of strokes per minute data and duty cycle data of the plurality of well-pumps. The instructions further enable the at least one processor module to receive commingled-flow measurement data using a plurality of commingled-flow measurement sensors. The commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells. The instructions enable the at least one processor module to determine well-flow data of the plurality of wells based on the commingled-flow measurement data, the field measurement data, and a plurality of conservation constraints generated by a constraint generator. The well-flow data are representative of fluid flow data from each of the plurality of wells. The instructions also enable the at least one processor module to control operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells.

DRAWINGS

[0008] These and other features and aspects of embodiments of the present invention will become better understood when the following detailed description is read with reference to the accompanying drawings in which like characters represent like parts throughout the drawings, wherein:

[0009] FIG. 1 is a schematic illustration of a control system for production in an oil field in accordance with an exemplary embodiment;

[0010] FIG. 2 is a schematic diagram illustrating signal flow corresponding to the control system of FIG. 1 in accordance with an exemplary embodiment;

[0011] FIG. 3 is a graph illustrating commingled-flow measurement representative of combined flow measurement in accordance with an exemplary embodiment;

[0012] FIG. 4 is a graph illustrating linear relationship between fundamental frequency values and strokes per minute values in accordance with an exemplary embodiment;

[0013] FIG. 5 shows graphical representation of a fluid velocity profile measurement and temperature profile measurement of a well in an oil field in accordance with an exemplary embodiment;

[0014] FIGS. 6A-6C are graphs representative of fluid flow data corresponding to a plurality of wells in accordance with an exemplary embodiment;

[0015] FIG. 6D is a graph representative of fluid flow data corresponding to a pool-line in accordance with an exemplary embodiment;

[0016] FIG. 7 is a flow chart illustrating a method for determining well-flow data representative of fluid flows in a plurality of wells in an oil field.in accordance with an exemplary embodiment; and

[0017] FIG. 8 is a flow chart illustrating a method for production in an oil field in accordance with an exemplary embodiment.

DETAILED DESCRIPTION

[0018] Embodiments of the present invention relate generally to fluid production from an oil field, and more particularly to systems and methods for determining fluid flow estimates of individual wells from fluid flow measurements at a pool-line.

[0019] FIG. 1 is a schematic illustration of a control system 108 for production in an oil field 100 in accordance with an exemplary embodiment. In the illustrated embodiment, the oil field 100 includes a plurality of wells 140 provided with a corresponding plurality of well-pumps 148. The plurality of well-pumps 148 is controlled by a plurality of pump-off controllers (POCs) 102. The pump-off controllers (POC) 102 are microprocessor based devices enabling autonomous operation of the well-pumps 148 such as sucker rod pumps, for example. Each POC 102 monitors conditions of the corresponding well 140 and shuts down the corresponding well-pump 148 when fluid level in the corresponding well 140 is below a certain level. The oil field 100 further includes a plurality of flow-lines 128 for coupling a production piping (not shown) of the plurality of wells 140 to a pool-line 104. The oil field 100 may further include a test device 106 for generating reference data for managing the fluid production of the oil field 100. The test device 106 may include a trailer test device and may use existing or additional sensors to acquire the reference data. A plurality of sensors 130, 132 is deployed in the oil field 100 to acquire oil-field data 134. The oil-field data 134 includes field measurement data 146 of the plurality of well-pumps 148. In one embodiment, the field measurement data 146 include speed data 110 and run-time data 136 generated by the well pumps 148. Specifically, the field measurement data 146 are sensed by a plurality of POC sensors 130. The oil-field data 134 further includes commingled-flow measurement data 112 measured by a plurality of commingled-flow measurement sensors 132 disposed in the pool-line 104. In one embodiment, the speed data 110 are indicative of the number of strokes of the well-pumps 148 in one minute duration. The run-time data 136 are indicative of the duty cycle of the well-pumps 148. The commingled-flow measurement data 112 are representative of fluid flow data in the pool-line 104 which is a sum of individual fluid flow rates from the plurality of flow-lines 128. In other words, the commingled-flow measurement data 112 are representative of a combined fluid flow data of the plurality of wells 140.

[0020] The control system 108 is communicatively coupled to the plurality of sensors 130, 132 and configured to receive the oil-field data 134 including the field measurement data 146 and the commingled-flow measurement data 112. The control system 108 is further configured to process the oil-field data 134 and generate well-flow data 138, representative of fluid flow data from each of the plurality of wells 140. The control system 108 is further configured to control operation of at least one of the plurality of well-pumps by a control signal 114 generated based on the well-flow data 138 to control fluid production from the plurality of wells 140. The control system 108 includes a data acquisition unit 116, a controller 120, an optimizer unit 118, a processor module 122, and a memory module 124 interconnected with each other by a communications bus 126.

[0021] The data acquisition unit 116 is communicatively coupled to the plurality of sensors 130, 132 and configured to receive the oil-field data 134 having the field measurement data 146 from the POC sensors 130 and the commingled-flow measurement data 112 from the commingled-flow measurement sensors 132. In one embodiment, the data acquisition unit 116 is configured to acquire the oil-field data 134 in the form of at least one of multiphase meter data, custody transfer data, virtual flow meter data, pressure data, temperature data, pump-off controller data, and trailer test data. The multiphase meter data are representative of flow data of one or more phases of a fluid in a well or in a pool-line. The custody transfer data are representative of data related to transactions involving transporting and transfer of fluid from one operator to another. The virtual flow meter data are representative of oil-field data estimated either by computation or through use of a software. The pump-off controller data are representative of the data generated by a pump-off controller used to control a corresponding well-pump 148. Specifically, the pump-off controller data include speed values, pressure values, torque values, and fluid flow values. The trailer test data are representative of data gathered from a data acquisition activity referred to as a 'well test' used to broaden knowledge and understanding of hydrocarbon properties and characteristics of a well. In some embodiments, the well test is performed by equipment mounted on a trailer or a mobile vehicle.

[0022] The optimizer unit 118 is communicatively coupled to the data acquisition unit 116 and configured to generate a plurality of conservation constraints 144 by a constraint generator 142, based on the commingled-flow measurement data 112 and the field measurement data 146. Specifically, the field measurement data 146 includes speed data 110 and run-time data 136. In one embodiment, the speed data 110 and the run-time data 136 are obtained from surrogate measurements obtained from one or more temperature transducers and load cell transducers. In one embodiment, the plurality of conservation constraints 144 is determined based on frequency domain analysis of the commingled-flow measurement data 112, the speed data 110, and the run-time data 136. In another embodiment, the plurality of conservation constraints 144 is determined based on a mass conservation principle. In yet another embodiment, the plurality of conservation constraints 144 is determined based on an energy conservation principle. In yet another embodiment, the plurality of conservation constraints 144 is determined based on a heat conservation principle. In yet another embodiment, the plurality of conservation constraints 144 is determined based on a momentum conservation principle.

[0023] The optimizer unit 118 is further configured to determine well-flow data 138 of the plurality of wells 140 based on the plurality of conservation constraints 144. Specifically, the optimizer unit 118 is configured to determine a cost function based on the plurality of conservation constraints 144. The optimizer unit 118 is further configured to optimize the cost function to determine the well-flow data 138. In one embodiment, the optimization refers to minimization of the cost function. In another embodiment, the optimization refers to maximization of the cost function.

[0024] In one embodiment, the optimizer unit 118 is configured to determine the cost function based on a probability distribution function of the well-flow data 138. The probability distribution function of the well-flow data 138 may be determined based on statistics of the field measurement data 146 and the commingled-flow measurement data 112. In one embodiment, the probability distribution function may be determined based on at least one of an apriori distribution function and an aposteriori distribution function of the well-flow data 138. In a further embodiment, the cost function may include one or more conservation equations and statistics corresponding to the oil-field. The statistics of the well-flow data 138 includes, but not limited to, a plurality of variance values. In one embodiment, the plurality of variance values may be determined by a variance model. In some embodiments, a trailer test data or pump card data may be used to determine the statistics of the well-flow data 138. Specifically, in one embodiment, the optimizer unit is configured to estimate a plurality of variance values of the well-flow data 138 based on the field measurement data 146.

[0025] The controller 120 is communicatively coupled to the data acquisition unit 116 and the optimizer unit 118 and configured to control operation of at least one of the plurality of well-pumps based on the well-flow data 138 to control fluid production from the plurality of wells 140. In one embodiment, the controlling fluid flow from one of the plurality of wells 140 is performed by controlling one or more of field operating parameters such as, but not limited to, injection of fluids and input current/voltage values of corresponding well pump.

[0026] The processor module 122 includes at least one of a general-purpose computer, a GPU, a digital signal processor, and a controller. In other embodiments, the processor module 122 includes a customized processor element such as, but not limited to, an application-specific integrated circuit (ASIC) and a field-programmable gate array (FPGA). The processor module 122 may be further configured to receive commands and parameters from an operator via a console that has a keyboard or a mouse or any other input device for generating the control signal 114. In some embodiments, the processor module 122 may perform one or more functions of at least one of the data acquisition unit 116, the optimizer unit 118, and the controller 120. The processor module 122 may include more than one processor co-operatively working with each other for performing intended functionalities. The processor module 122 is further configured to store and retrieve contents into and from the memory module 124. In one embodiment, the processor module 122 is configured to initiate and control the functionality of at least one of the data acquisition unit 116, the optimizer unit 118, and the controller 120.

[0027] In one embodiment, the memory module 124 may be a random-access memory (RAM), read only memory (ROM), flash memory or any other type of computer readable memory accessible by at least one of the data acquisition unit 116, optimizer unit 118, and the controller 120. In one embodiment, the memory module 124 may be a non-transitory computer readable medium encoded with a program having a plurality of instructions to instruct at least one of the data acquisition unit 116, optimizer unit 118, and the controller 120 to perform a sequence of steps to generate the well-flow data 138 of the plurality of wells 140. The program may be used to further instruct the control system 108 to control the well-pumps 148 in the plurality of wells 140.

[0028] In one embodiment, a non-transitory computer readable medium having instructions that enable at least one processor module 122 to determine well-flow data 138 of the plurality of wells 140 is disclosed. The instructions enable the at least one processor module 122 to receive the field measurement data 146 of the plurality of well-pumps 148. The instructions further enable the at least one processor module 122 to receive the commingled-flow measurement data 112, using the commingled-flow measurement sensors 132. The instructions enable the at least one processor module 122 to determine the well-flow data 138 of the plurality of wells 140 based on the commingled-flow measurement data 112, the field measurement data 146, and the plurality of conservation constraints. The instructions also enable the at least one processor module 122 to control operation of at least one of the plurality of well-pumps based on the well-flow data 138 to control fluid production from the plurality of wells 140.

[0029] FIG. 2 is a schematic diagram 200 illustrating signal flow of the control system 108 in accordance with an exemplary embodiment of FIG. 1. As discussed previously, the field measurement data 146 includes the speed data 110 and the run-time data 136. In the illustrated embodiment, the field measurement data 146 includes at least one of a temperature value 226, a pressure value 228, and a density value 230 of a fluid at one or more of the plurality of flow-lines 128 and the pool-line 104. In one embodiment, the field measurement data 146 may also include fluid flow data 224 of one or more of the plurality of flow-lines 128.

[0030] In one embodiment, the constraint generator 142 of the optimizer unit 118 is configured to generate at least one of a mass conservation constraint 234, an energy conservation constraint 236, a heat conservation constraint 238 and a momentum conservation constraint 240. The mass conservation constraint 234 is determined based on mass conservation equation represented by:

$$\dot{m}_1+\dot{m}_2+\dot{m}_3+...=\dot{m}_p \quad (1)$$

where, $\dot{m}_1$, $\dot{m}_2$, $\dot{m}_3$ are accumulated rate of change of mass in the plurality of flow-lines 128 and $\dot{m}_p$ is accumulated rate of change of mass in the pool-line 104 during a specified time period. The energy conservation constraint 236 is represented by:

$$\dot{E}_1+\dot{E}_2+\dot{E}_3+...=\dot{E}_p \qquad (2)$$

where, $\dot{E}_1$, $\dot{E}_2$, $\dot{E}$ are accumulated rate of change of energy in a plurality of flow-lines and $\dot{E}_p$ is accumulated rate of change of energy in the pool-line 104 during a specified time period. The momentum conservation constraint 238 is represented by:

$$\sum_i \dot{m}_i \left(h_{ref} + C_{p,i}\left(T_i - T_{ref}\right)\right)=\dot{m}_p \left(h_{ref} + C_p\left(T_i - T_{ref}\right)\right) \qquad (3)$$

where, $\dot{m}_i$ is accumulated rate of change of mass in i^{th} flowline of the plurality of flow-lines 128, h_{ref} is reference enthalpy, $C_{p,i}$ is specific temperature corresponding to i^{th} flow-line, T_i is temperature of fluid in i^{th} flow-line, T_{ref} is reference temperature, $\dot{m}_p$ is accumulated rate of change of mass in the pool-line 104 and C_p is specific temperature corresponding to the pool-line 104.

[0031] Conservation principle for a plurality of observed quantities is represented by:

$$\sum_{i=1}^{n} \hat{Q}_i = \hat{Q}_p \qquad (4)$$

where, $\hat{Q}_1$, $\hat{Q}_2$, $\hat{Q}_n$ are the measured quantities from n wells for a fixed interval of time Δt, and $\hat{Q}_p$ is the observed quantity sensed by a master meter across the same interval Δt at the pool-line 104. In the illustrated embodiment, the optimizer unit 118 includes a maximum likelihood generator 212 for generating the maximum likelihood estimates of well-flow data 138. Specifically, the maximum likelihood generator 212 is configured to model the observed quantities $\hat{Q}_i$ (where $i = 1, 2, 3, ..., N, p$) as zero mean normal random variables having known variance parameter values. The maximum likelihood generator 212 is further configured to generate a joint log-likelihood function of the observed quantities $\hat{Q}_i$ represented by:

$$L(\hat{Q}_1, \hat{Q}_2 ... \hat{Q}_n, \hat{Q}_p | \sigma_1, \sigma_2 ... \sigma_n, \sigma_p) \propto \sum_{i=1}^{n}(\hat{Q}_i - Q_i)^2/(\sigma_i)^2 + (\hat{Q}_p - Q_p)^2/(\sigma_p)^2 \qquad (5)$$

where, σ_1, σ_2, ..., σ_n, σ_p are variance values corresponding to the plurality of measured quantities. The optimizer unit 118 is further configured to maximize the joint log-likelihood function to generate a maximum likelihood estimate 218 of the well-flow data 138.

[0032] Further, the optimizer unit 118 includes a posteriori function generator 214 configured to generate a posterior probability function based on the log-likelihood function represented by equation (5). The posteriori probability function is a joint probability of the log-likelihood function and the posteriori probability distribution function of one or more of the observed quantities $\hat{Q}_i$. In one embodiment, the posteriori probability function is represented by:

$$f(\{\hat{Q}_i\}/L) = L(\hat{Q}_1, \hat{Q}_2 \ldots \hat{Q}_n, \hat{Q}_p | \sigma_1, \sigma_2 \ldots \sigma_n, \sigma_p)\, g(\{\hat{Q}_i\})$$

Where, *f()* is a aposteriori probability function, *g()* is a prior distribution function corresponding to one or more of the observed quantities $\hat{Q}_i$. The optimizer unit 118 is configured to generate a maximum aposteriori (MAP) estimate 220 of the well-flow data 138.

[0033] Additionally, the optimizer unit 118 includes a power spectrum generator 210 configured to determine a power spectral density based on the commingled-flow measurement data 112. The power spectral density includes a frequency signature having a plurality of peak values corresponding to a plurality of fundamental frequencies. The frequency signature is representative of speed of the plurality of well-pumps 148. The optimizer unit 118 is further configured to determine the plurality of peak values of the power spectral density. The optimizer unit 118 is also configured to identify a set of wells from the plurality of wells 140, corresponding to the plurality of peak values, based on subset stroke data from the strokes per minute data, corresponding to the identified set of wells. In one embodiment, a plurality of filters configured to extract the plurality of fundamental frequencies is used to process the power spectral density data. The power spectral density data is processed by the plurality of filters sequentially by applying one filter among the plurality of filters at a time and generating a corresponding output signal and a residual signal. The residual signal is processed further by remaining filters among the plurality of filters to detect weaker fundamental frequencies. The output signal from each of the plurality of filters is bias adjusted to compensate for a corresponding DC component. The output signals from the plurality of filters are correlated with the speed data corresponding to the well pumps 148 to identify the set of wells. Further, the optimizer unit 118 is configured to determine a plurality of mean flow rate values 222 of the identified set of wells based on subset duty cycle data from the run-time data 136. In one embodiment, the duty cycle data is used in conjunction with the duration (and timings) of operation of the plurality of well pumps 148 to refine the plurality of mean flow rate values

222. In some embodiments, the duty cycle data is also used to identify a subset of the plurality of frequencies to enhance the accuracy of the plurality of mean flow rate values 222.

[0034] In one embodiment, data decomposition techniques such as, but not limited to, cosine transformation, Karhunen-Loeve transform, and wavelet transform may be used to process the commingled-flow measurement data 112. The plurality of peak values may be identified in the transformed domain based on the decomposed commingled-flow measurement data 112. The optimizer unit 118 is configured to identify the set of wells based on the subset stroke data from the strokes per minute data. In other embodiments, a general signature of the well-flow data 138 corresponding to individual wells 140 may be derived from the decomposed commingled-flow measurement data 112. The set of wells is identified based on the general signature, speed data 110, and the run-time data 136. In one embodiment, a model for tracking correlation between the fundamental and harmonic frequency amplitudes may be employed to identify the set of wells.

[0035] The optimizer unit 118 is configured to determine a cost function based on at least one of a plurality of conservation equations representative of the plurality of conservation constraints 234, 236, 238, 240 determined based on the field measurement data 146 and the commingled-flow measurement data 112. In another embodiment, the cost function may include a distribution function characterized by one or more of a plurality of variance values of the well-flow data 138 based on the field measurement data 146. In one embodiment, the plurality of variance values may be determined based on a correlation matrix based on at least one parameter of the field measurement data 146. In an alternate embodiment, a variance model corresponding to a variance value among the plurality of variance values is determined. The variance model is representative of a polynomial equation. The optimizer unit 118 is further configured to determine an estimate of a mean and a standard deviation corresponding to the variance value based on trailer test data and the variance model. In another embodiment, the plurality of variance values is determined based on pump card data representative of relationship between stroke values and load values of the pump-off controller 102.

[0036] FIG. 3 is a graph 300 illustrating commingled-flow measurement in accordance with an exemplary embodiment. The graph 300 includes an x-axis 302 representative of normalized frequency in radians per sample units and y-axis 304 representative of normalized power content of flow measurements in decibel per radians per sample unit. The graph 300 further includes a curve 306 representative of pool-line flow data corresponding to a pool-line which receives combined fluid flow from production pipelines of five wells. The curve 306 includes a plurality of peak values 308, 310, 312, representative of a plurality of harmonic frequency values corresponding to the plurality of wells. In one embodiment, the peak value 308 may correspond to a first well having a well-pump operating at 9.84 strokes per minute (SPM) and producing a fluid flow rate of 323 barrels per day (BPD). In another embodiment, the peak value 310 may correspond to a second well-pump having a pump operating at 10.2 SPM and producing a fluid flow rate of 986 BPD. In yet another embodiment, the peak value 312 may correspond to a third well having a well-pump operating at 11.7 SPM and producing a fluid flow rate of 636 BPD. In one embodiment, a plurality of well-pumps may operate at SPM values ranging from 6 to 14 and produce fluid-flow rates in a range from 150 BPD to 1600 BPD.

[0037] FIG. 4 is a graph 400 illustrating a linear relationship between a fundamental frequency in a frequency spectrum and strokes per minute frequency. The graph 400 includes an x-axis 402 representative of a frequency in Hertz from a pump-off controller derived based on stroke per minute data corresponding to a plurality of well-pumps. The graph 400 also includes a y-axis 404 representative of a fundamental frequency in Hertz corresponding to a plurality of peak values observed in the power spectrum of the commingled-flow measurement data. The graph 400 includes a plurality of points 406 that relate fundamental frequencies corresponding to the peak values of the power spectrum to frequency values corresponding to the stroke frequency values of the plurality of well-pumps. It may be noted that the plurality of points 406 exhibit a linear trend represented by a line 408. The plurality of points 406 are distinctly identifiable although some of the points appear in a cluster, enabling identification of a well among the plurality of wells corresponding to a fundamental frequency. In one embodiment, a first well having a fluid flow rate of 405 barrels per day (BPD) may have a well-pump operating at 10.6 strokes per minute (SPM). A second well having a fluid flow rate of 479 BPD may be operated by a well-pump at 10.2 SPM. In some embodiments, the SPM values of the well-pumps may vary in a range from 6 to 14 and fluid flow rates in a range of 150 BPD to 1600 BPD. Further, a plurality of well signature signals representative of well-flow measurements, corresponding to the plurality of wells may be derived from the power spectrum. The fluid flow rate of each of the plurality of wells may be derived based on corresponding well signature signal and duty cycle data of the corresponding well-pump.

[0038] FIG. 5 illustrates a first graph 500 representing a velocity profile measurement and a second graph 550 representing a temperature profile measurement of a well in an oil field in accordance with an exemplary embodiment. The first graph 500 includes an x-axis 502 representative of time index and y-axis 504, representative of flow velocity values of production fluid from the well. The first graph 500 includes a curve 506 representative of fluid velocity profile of the well. The second graph 550 includes an x-axis 552 representative of time index and y-axis 554 representative of temperature values of production fluid from the well. The second graph 550 includes a curve 556, representative of temperature profile of the production fluid from the well. It may be observed that the curves 506, 556 exhibits periodic variations representative of duty cycle data of the well.

[0039] FIGS. 6A-6D are graphs 600, 602, 604, 606, representative of fluid flow data corresponding to a first well, a second well, a third well, and a pool-line respectively in accordance with an exemplary embodiment. The graph 600 includes an x-axis 608, representative of time in and a y-axis 610 representative of flow amplitude. The graph 600 includes a curve 612 representative of fluid flow in the first well. The graph 602 includes an x-axis 614 representative of time and a y-axis 616 representative of flow amplitude. The graph 602 includes a curve 618, representative of fluid flow in the second well. The graph 604 includes an x-axis 620 representative of time in and a y-axis 622 representative of flow amplitude. The graph 604 includes a curve 624, representative of fluid flow in the third well. The graph 606 includes an x-axis 626 representative of time and a y-axis 628 representative of flow amplitude. The graph 606 includes a curve 630 representative of commingled flow measurement data in the pool-line receiving fluid from a plurality of wells including the first well, the second well, and the third well. The curve 630 is representative of commingled flow signature signal with a normalized amplitude and includes the curves 612, 618 and 624 representative of well-flow signature signals obtained by processing the commingled flow signature signal by the plurality of filters. It may be observed that the well-pumps are operating at different duty cycles producing varying fluid-flows from individual wells.

[0040] An example of determining well-flow data of the plurality of wells is provided in Table-1. The Table–1 tabulates data corresponding to six wells. The commingled flow signature signal is acquired at the pool-line. An average comingled flow value of 5712.7 BPD (barrels per day) is determined by averaging the commingled flow signature signal. A plurality of frequency values corresponding to a plurality of wells are determined from a spectrum of the commingled flow signature signal as

TABLE-1

Input is measured commingled flow signature signal

Average commingled flow value 5712.7 BPD

Frequency from commingled flow spectrum	Frequency obtained from SPM values of pumps	Well Name	Duty Cycle values of pumps	Estimated well-flow (BPD)	Measured well-flow (BPD)	Error % between estimated and measured well-flows
0.14844	0.14838	2-9R	0.99	955.8	736.5	-29.8
0.11963	0.11934	3-6	1	1523.3	1445.5	-5.4
0.15234	0.15214	3-8	1	1089.6	1191.8	8.6
0.14063	0.14055	C-4R	1	615.9	625.1	1.5
0.14551	0.1456	C-7R	0.91	665.6	502.4	-32.5
0.16504	0.16517	C-85	1	1223.7	1211.4	-1

provided in the first column of the Table -1. A plurality of well-flow signature signals corresponding to the plurality of wells is determined as discussed earlier. Further, a plurality of operating frequency values of the well pumps is determined based on the strokes per minute data of the well pumps operating in the plurality of wells. A one-to-one correspondence is established between the plurality of frequency values obtained from the spectrum of the commingled flow signature signal and the plurality of the operating frequency values. The plurality of wells is identified corresponding to the plurality of well-flow signature signals as provided in the third column of the Table-1. A plurality of average well flows is determined based on the plurality of well-flow signature signals as provided in fifth column of the Table-

1. The duty cycle values corresponding to the well pumps are provided in fourth column of the Table-1 are used to determine the plurality of average well flow values. In the sixth column of the Table-1, a plurality of measured average well flow values is provided for comparison purpose. Estimation errors expressed in percentage values are provided in seventh column of the Table-1. It may be observed that four out of five well-flows are estimated with less than ten percent estimation error.

[0041] FIG. 7 is a flow chart illustrating a method 700 for determining well-flow data representative of fluid flows corresponding to a plurality of wells in an oil field.in accordance with an exemplary embodiment. The method 700 includes receiving commingled-flow measurement data and stroke per minute (SPM) data at step 702. The method 700 further includes determining a power spectral density of the pool-line data at step 704. The method 700 further includes determining a plurality of peak values corresponding to a plurality of fundamental frequencies of the power spectral density at step 706. Further, the method 700 includes designing a plurality of filters based on the plurality of fundamental and their corresponding harmonic frequencies at step 708. The method 700 further includes generating a plurality of well signature signals by filtering the commingled-flow measurement data by the plurality of filters. The plurality of well signatures is representative of fluid flow measurements from the plurality of wells. At step 712, a set of wells is identified from the plurality of wells corresponding to the determined plurality of peak values. The identification of the set of wells is based on matching the plurality of fundamental frequency values with a corresponding frequency value derived from the SPM data. At step 714, a plurality of mean flow rate values is determined based on subset duty cycle data from the run-time data corresponding to the set of wells.

[0042] FIG. 8 is a flow chart illustrating a method 800 for fluid production in an oil field in accordance with an exemplary embodiment. The method 800 includes receiving field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells at step 802. The field measurement data are representative of strokes per minute data and duty cycle data of the plurality of well-pumps. In one embodiment, the field measurement data include at least one of multiphase meter data, custody transfer data, virtual flow meter data, pressure data, temperature data, pump-off controller data, and trailer test data.

[0043] The method further includes receiving commingled-flow measurement data using a plurality of commingled-flow measurement sensors at step 804. The commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells. The method 800 also includes determining well-flow data of the plurality of wells based on the commingled-flow measurement data, the field measurement data, and a plurality of conservation constraints generated by a constraint generator at step 806. In one embodiment, the plurality of conservation constraints includes at least one of a mass conservation constraint, an energy conservation constraint, a heat conservation constraint and a momentum conservation constraint.

[0044] In one embodiment, the step 806 includes determining a power spectral density based on the commingled-flow measurement data. Further, a plurality of peak values corresponding to a plurality of fundamental frequencies of the power spectral density is determined. The step 806 also includes identifying a set of wells from the plurality of wells, corresponding to the plurality of peak values, based on subset stroke data corresponding to the set of wells. The step 806 further includes determining a plurality of mean flow rate values based on subset duty cycle data from the duty cycle data, of the identified set of wells.

[0045] In another embodiment, the step 806 includes determining a probability distribution function corresponding to the well-flow data, based on the field measurement data and the commingled-flow measurement data. Further, a cost function based on the probability distribution function is determined. An optimization is performed using the cost function to determine the well-flow data. In a further embodiment, the step 806 includes estimating a plurality of variance values based on the field measurement data. In one embodiment, the probability distribution function is determined by determining at least one of an apriori distribution function and an aposteriori distribution function corresponding to the well-flow data. The cost function is determined by determining a plurality of conservation equations based on the field measurement data and the commingled-flow measurement data. In one embodiment, the cost function may also include one of the probability distribution functions.

[0046] It may be noted that in some embodiments, one or more of the probability distribution functions may be modelled as a normal distribution characterized by a plurality of variance values. In one embodiment, the plurality of variance values is estimated by determining a correlation matrix based on at least one parameter of the field measurement data.

In another embodiment, the plurality of variance values is estimated by determining a variance model corresponding to a variance value among the plurality of variance values. The variance model is represented as a polynomial equation. Further, an estimate of a mean and a standard deviation corresponding to the variance value are determined based on trailer test data and the variance model. In another embodiment, the plurality of variance values is determined by using pump card data representative of relationship between stroke values and load values of a pump-off controller.

[0047] Further, the method 700 also includes controlling operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells at step 808.

[0048] Embodiments of the disclosed technique disclose requirement of reduced number of multiphase meters for determining a real-time fluid flow data from the plurality of wells. One multiphase meter may be used in the pool-line and a few additional multiphase meters may be deployed at convenient locations in the oil field to measure field measurement data. The fluid flow data determined using the disclosed technique may be used for diagnostics, identify failures in the field, enable handling missing data, and provides inferred fluid production with higher confidence. The disclosed technique may be employed for characterization of oil wells without the need for special measurements on a per-well basis and thereby enable efficient operation of the oil-field.

[0049] It is to be understood that not necessarily all such objects or advantages described above may be achieved in accordance with any particular embodiment. Thus, for example, those skilled in the art will recognize that the systems and techniques described herein may be embodied or carried out in a manner that achieves or improves one advantage or group of advantages as taught herein without necessarily achieving other objects or advantages as may be taught or suggested herein.

[0050] While the technology has been described in detail in connection with only a limited number of embodiments, it should be readily understood that the specification is not limited to such disclosed embodiments. Rather, the technology can be modified to incorporate any number of variations, alterations, substitutions or equivalent arrangements not heretofore described, but which are commensurate with the spirit and scope of the claims. Additionally, while various embodiments of the technology have been described, it is to be understood that aspects of the specification may include only some of the described embodiments. Accordingly, the specification is not to be seen as limited by the foregoing description, but is only limited by the scope of the appended claims.

CLAIMS:

1. A method comprising:

receiving field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells from a plurality of pump-off controller (POC) sensors, wherein the field measurement data are representative of speed data and run-time data of the plurality of well-pumps;

receiving commingled-flow measurement data using a plurality of commingled-flow measurement sensors, wherein the commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells;

determining, by an optimizer unit, well-flow data of the plurality of wells based on the commingled-flow measurement data, the field measurement data, and a plurality of conservation constraints generated by a constraint generator, wherein the well-flow data are representative of fluid flow data from each of the plurality of wells; and

controlling operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells.

2. The method of claim 1, wherein the plurality of conservation constraints comprises at least one of a mass conservation constraint, an energy conservation constraint, a heat conservation constraint and a momentum conservation constraint.

3. The method of claim 1, wherein the field measurement data comprises at least one of a temperature value, a pressure value, and a torque value corresponding to the plurality of well-pumps.

4. The method of claim 1, wherein determining the well-flow data comprises:

determining a power spectral density based on the commingled-flow measurement data;

determining a plurality of peak values corresponding to a plurality of fundamental frequency values of the power spectral density;

identifying a set of wells from the plurality of wells, corresponding to the plurality of peak values, based on subset stroke data from the speed data, corresponding to the plurality of wells; and determining a plurality of mean flow rate values based on subset duty cycle data from the run-time data, of the identified set of wells.

5. The method of claim 1, wherein determining the well-flow data comprises:

determining a probability distribution function corresponding to the well-flow data, based on the field measurement data and the commingled-flow measurement data;

determining a cost function based on the probability distribution function; and

performing an optimization using the cost function to determine the well-flow data.

6. The method of claim 5, wherein determining the probability distribution function comprises determining at least one of an apriori distribution function and an aposteriori distribution function of the well-flow data.

7. The method of claim 5, wherein the cost function comprises a plurality of conservation equations determined based on the field measurement data and the commingled-flow measurement data.

8. The method of claim 1, wherein determining the well-flow data comprises estimating a plurality of variance values based on the field measurement data.

9. The method of claim 8, wherein estimating the plurality of variance values comprises determining a correlation matrix based on at least one parameter of the field measurement data.

10. The method of claim 8, wherein estimating the plurality of variance values comprises:

determining a variance model corresponding to a variance value among the plurality of variance values, wherein the variance model is a polynomial equation; and

determining an estimate of a mean and a standard deviation corresponding to the variance value among the plurality of variance values determined based on the variance model.

11. A system comprising:

a plurality of sensors disposed in an oil field, wherein the plurality of sensors comprises a plurality of pump-off controller (POC) sensors disposed on a plurality of well-pumps and a plurality of commingled-flow measurement sensors disposed on a pool-line;

a data acquisition unit configured to:

receive field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells from the plurality of POC sensors, wherein the field measurement data are representative of speed data and run-time data of the plurality of well-pumps; and

receive commingled-flow measurement data using the plurality of commingled-flow measurement sensors, wherein the commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells;

an optimizer unit communicatively coupled to the data acquisition unit and configured to:

generate a plurality of conservation constraints using a constraint generator, based on the commingled-flow measurement data and the field measurement data; and

determine well-flow data corresponding to the plurality of wells based on the commingled-flow measurement data, the field measurement data, and the plurality of conservation constraints, wherein the well-flow data are representative of fluid flow data from each of the plurality of wells; and

a controller communicatively coupled to the data acquisition unit and the optimizer unit and configured to control operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells.

12. The system of claim 11, wherein the optimizer unit is configured to generate at least one of a mass conservation constraint, an energy conservation constraint, a heat conservation constraint and a momentum conservation constraint.

13. The system of claim 11, wherein the data acquisition unit is configured to acquire at least one of a flow value, a temperature value, a pressure value, a torque value corresponding to the plurality of well-pumps.

14. The system of claim 11, wherein the optimizer unit is configured to:

determine a power spectral density based on the commingled-flow measurement data;

determine a plurality of peak values corresponding to a plurality of fundamental frequencies of the power spectral density;

identify a set of wells from the plurality of wells, corresponding to the plurality of peak values, based on subset stroke data from the speed data, corresponding to the plurality of wells; and

determine a plurality of mean flow rate values based on subset duty cycle data from the run-time data, of the identified set of wells.

15. The system of claim 11, wherein the optimizer unit is configured to:

determine a probability distribution function corresponding to the well-flow data, based on the field measurement data and the commingled-flow measurement data;

determine a cost function based on the probability distribution function; and

perform an optimization using the cost function to determine the well-flow data.

16. The system of claim 15, wherein the optimizer unit is configured to determine the probability distribution function comprises determining at least one of an apriori distribution function and an aposteriori distribution function of the well-flow data.

17. The system of claim 16, wherein the optimizer unit is configured to determine a cost function based on a plurality of conservation equations determined based on the field measurement data and the commingled-flow measurement data.

18. The system of claim 11, wherein the optimizer unit is configured to estimate a plurality of variance values corresponding to the well-flow data based on the field measurement data.

19. The system of claim 18, wherein the optimizer unit is configured to determine a correlation matrix corresponding to the oil field based on at least one parameter of the field measurement data.

20. The system of claim 18, wherein the optimizer unit is configured to:

determine variance model corresponding to a variance value among the plurality of variance values, wherein the variance model is a polynomial equation;

determine an estimate of a mean and a standard deviation corresponding to the variance value among the plurality of variance values determined based on the variance model.

21. A non-transitory computer readable medium having instructions to enable at least one processor module to:

receive field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells from a plurality of pump-off controller (POC) sensors, wherein the field measurement data are representative of strokes per minute data and duty cycle data of the plurality of well-pumps;

receive commingled-flow measurement data using a plurality of commingled-flow measurement sensors, wherein the commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells;

determine well-flow data of the plurality of wells based on the commingled-flow measurement data, the field measurement data, and a plurality of conservation constraints generated by a constraint generator, wherein the well-flow data are representative of fluid flow data from each of the plurality of wells; and

control operation of at least one of the plurality of well-pumps based on the well-flow data to control fluid production from the plurality of wells.

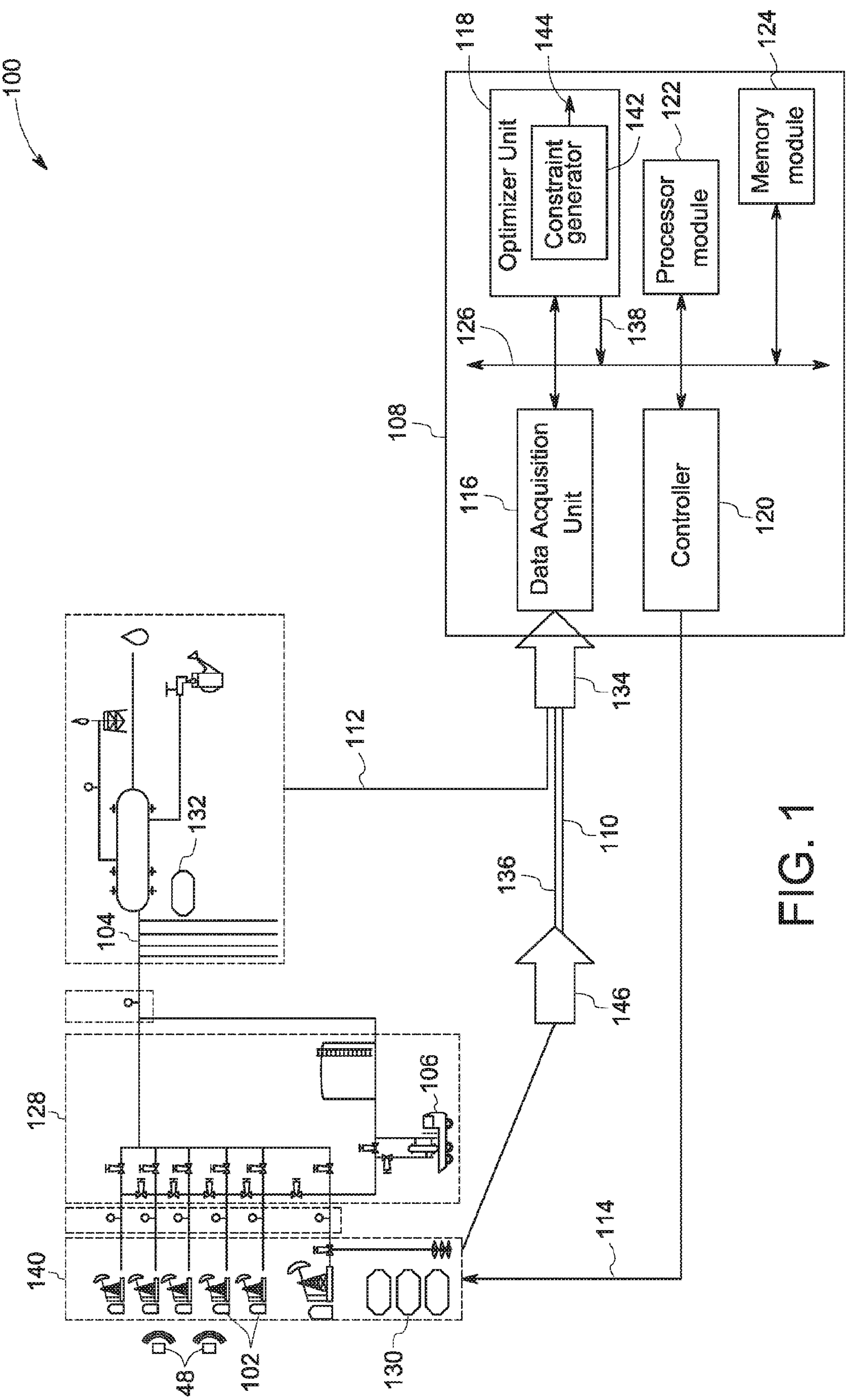
100
118
144
142
124
122
Optimizer Unit
Constraint generator
Processor module
Memory module
126
138
108
116
Data Acquisition Unit
Controller
120
112
134
110
136
146
104
132
128
106
140
114
148
102
130

FIG. 1

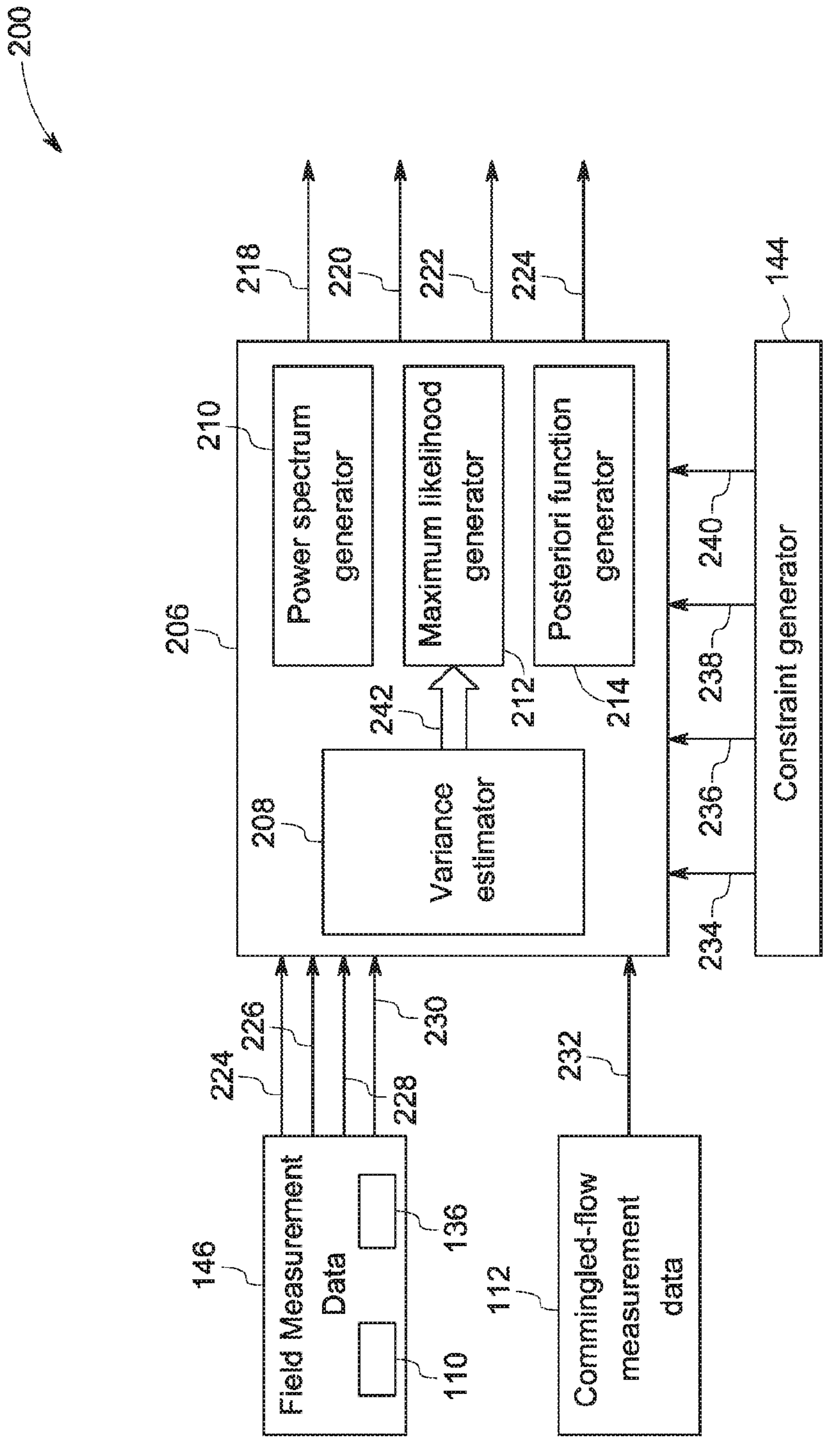
200
218
220
222
224
210
Power spectrum generator
Maximum likelihood generator
Posteriori function generator
206
242
212
214
208
Variance estimator
240
238
236
234
144
Constraint generator
146
Field Measurement Data
110
136
224
226
228
230
232
112
Commingled-flow measurement data

FIG. 2

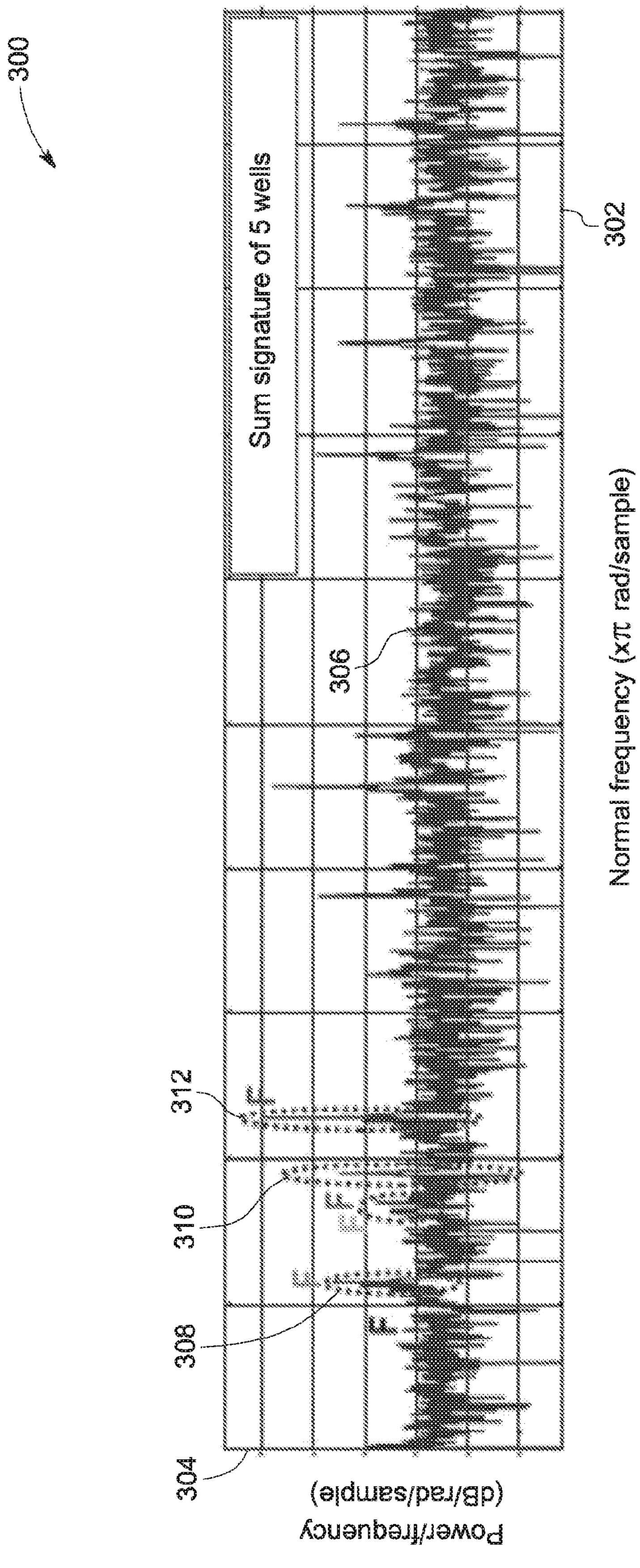
300
Sum signature of 5 wells
302
306
312
310
308
304
Normal frequency (xπ rad/sample)
Power/frequency (dB/rad/sample)

FIG. 3

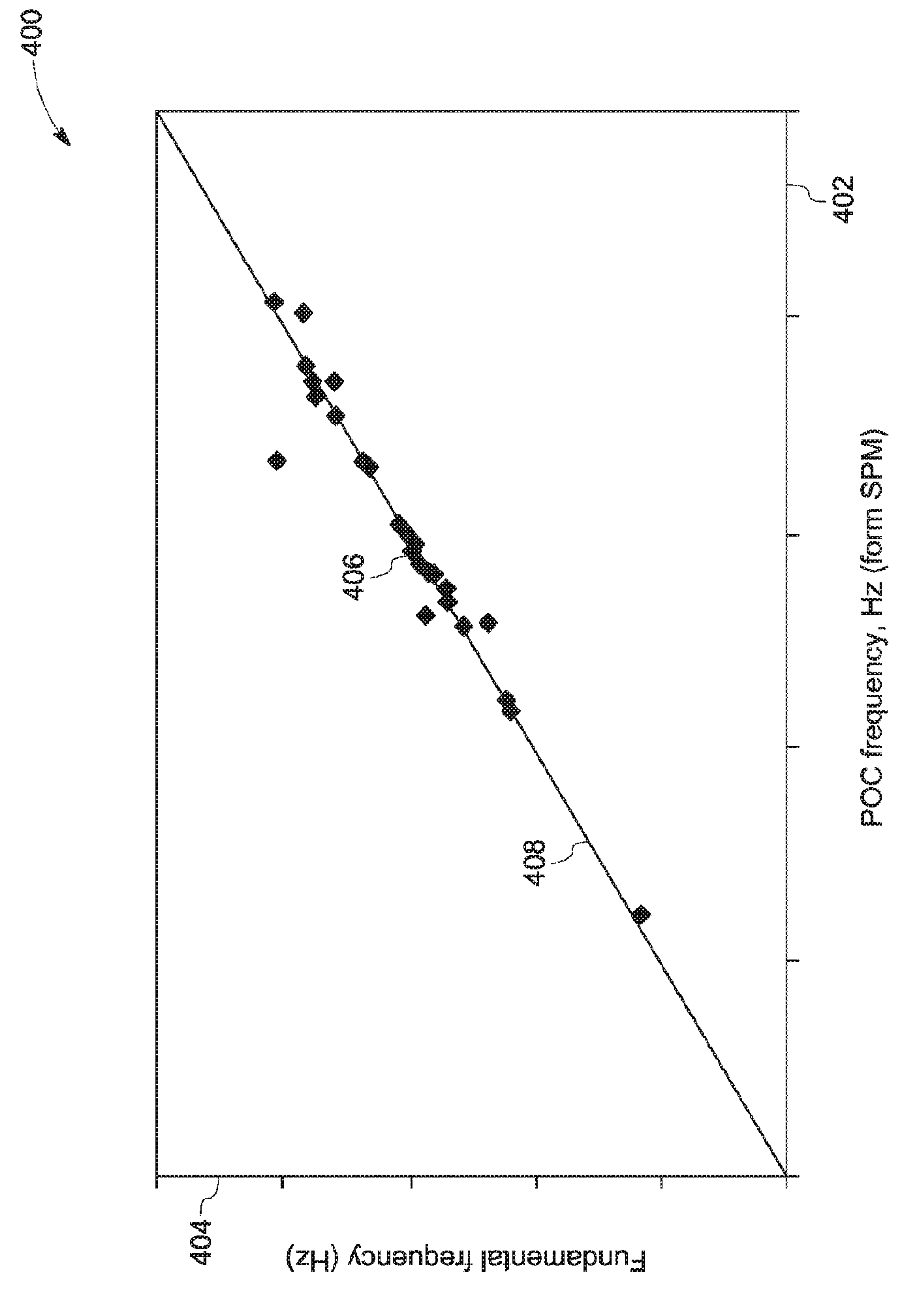
400
402
404
406
408
POC frequency, Hz (form SPM)
Fundamental frequency (Hz)

FIG. 4

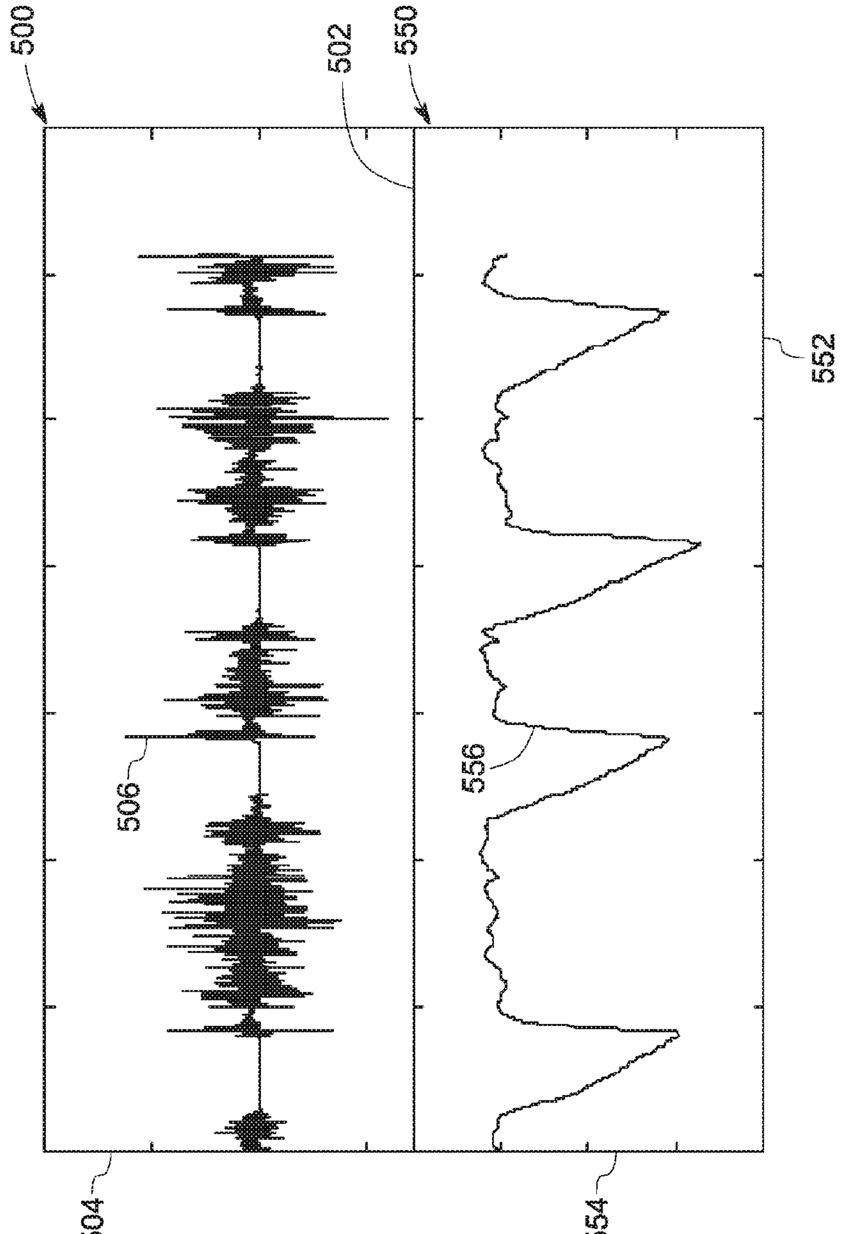

FIG. 5

FIG. 6A

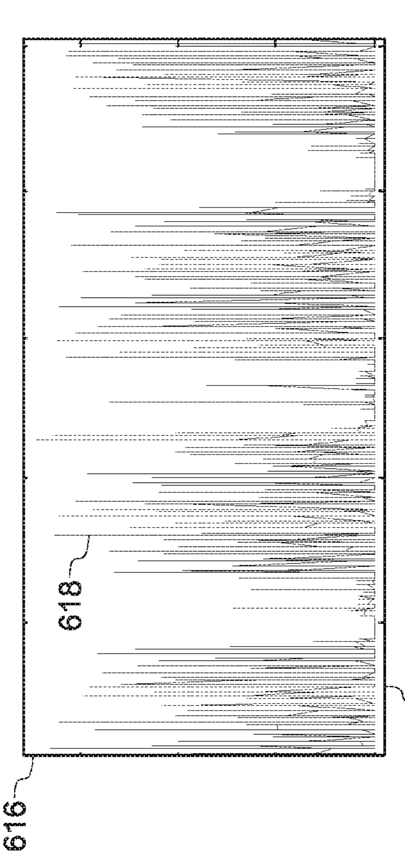

FIG. 6B

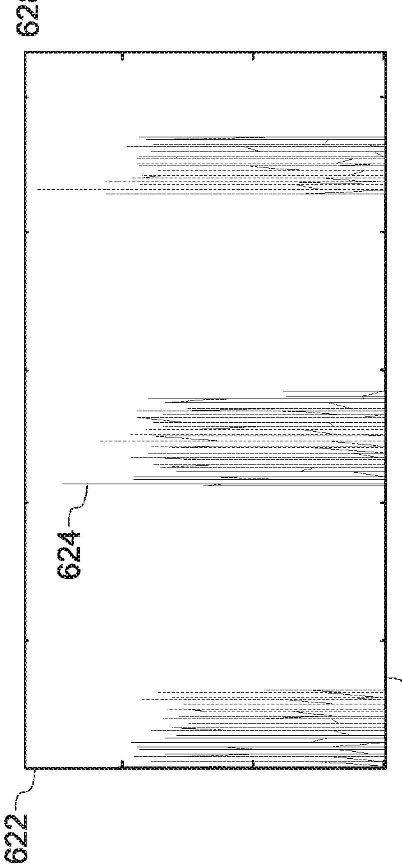

FIG. 6C

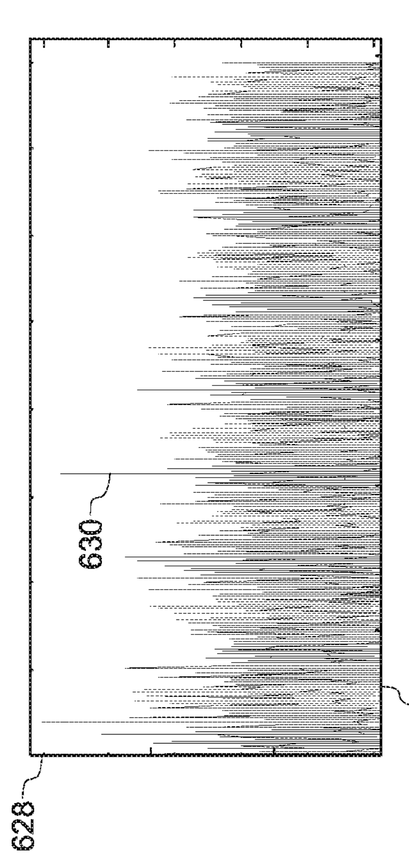

FIG. 6D

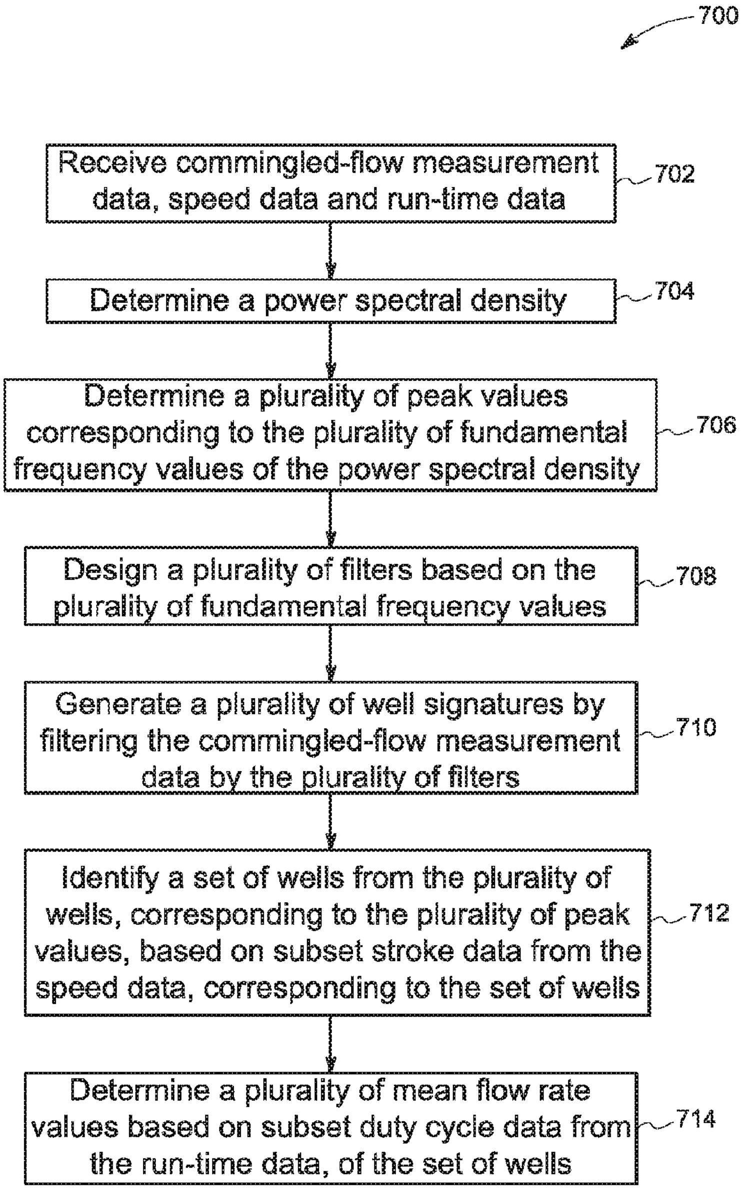
700
Receive commingled-flow measurement data, speed data and run-time data
702
Determine a power spectral density
704
Determine a plurality of peak values corresponding to the plurality of fundamental frequency values of the power spectral density
706
Design a plurality of filters based on the plurality of fundamental frequency values
708
Generate a plurality of well signatures by filtering the commingled-flow measurement data by the plurality of filters
710
Identify a set of wells from the plurality of wells, corresponding to the plurality of peak values, based on subset stroke data from the speed data, corresponding to the set of wells
712
Determine a plurality of mean flow rate values based on subset duty cycle data from the run-time data, of the set of wells
714

FIG. 7

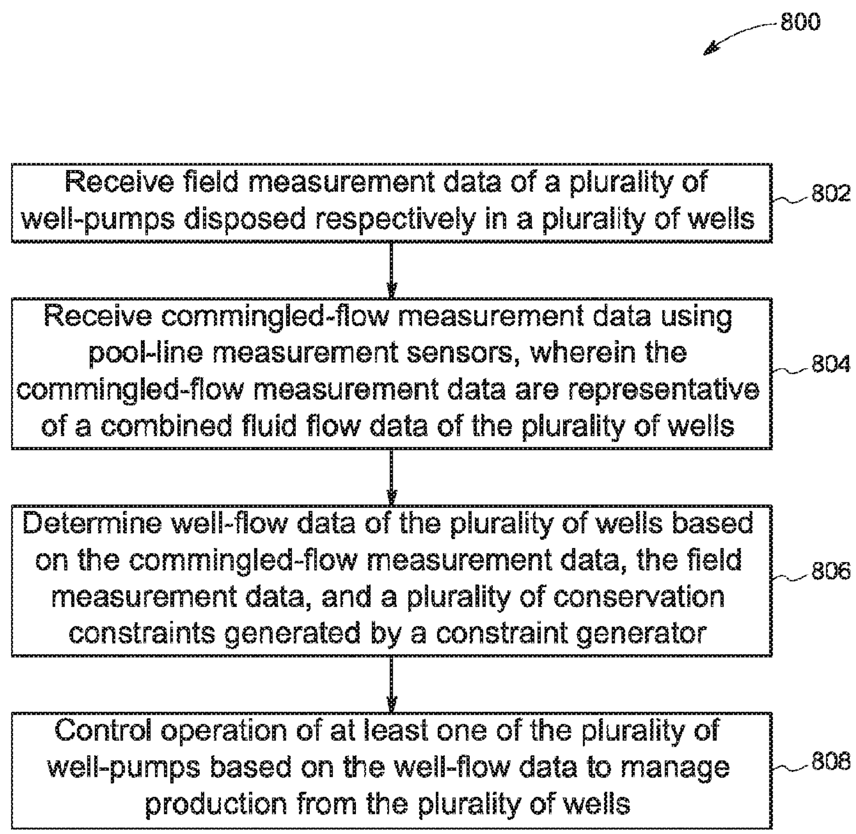
800
Receive field measurement data of a plurality of well-pumps disposed respectively in a plurality of wells
802
Receive commingled-flow measurement data using pool-line measurement sensors, wherein the commingled-flow measurement data are representative of a combined fluid flow data of the plurality of wells
804
Determine well-flow data of the plurality of wells based on the commingled-flow measurement data, the field measurement data, and a plurality of conservation constraints generated by a constraint generator
806
Control operation of at least one of the plurality of well-pumps based on the well-flow data to manage production from the plurality of wells
808

FIG. 8

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2018/051203

A. CLASSIFICATION OF SUBJECT MATTER

E21B 43/12(2006.01)i, F04B 49/06(2006.01)i, F04B 23/04(2006.01)i, F04B 47/06(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 43/12; E21B 43/00; E21B 47/00; E21B 49/08; G01F 1/24; G01F 1/26; G01V 1/40; F04B 49/06; F04B 23/04; F04B 47/06

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: field measurement, well-pump, pump-off, commingled-flow, optimize

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2010-0023269 A1 (YUSTI et al.) 28 January 2010 See paragraphs [0011]-[0166]; claim 10; and figures 7-8.	1-21
Y	WO 89-02579 A1 (WALKER et al.) 23 March 1989 See page 26, line 7 - page 29, line 32; page 67, line 19 - page 68, line 1; and figure 1.	1-21
A	US 2011-0048122 A1 (LE FOLL et al.) 03 March 2011 See paragraphs [0028]-[0091]; and figures 2-7d.	1-21
A	US 6279660 B1 (HAY, ARTHUR D.) 28 August 2001 See column 3, line 19 - column 7, line 21; and figures 1-8.	1-21
A	WO 2007-116008 A1 (SHELL INTERNATIONALE RESEARCH MAATSCHAPPIJ B.V. et al.) 18 October 2007 See page 11, line 24 - page 23, line 2; and figures 1-3.	1-21

☐ Further documents are listed in the continuation of Box C.　　☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
10 January 2019 (10.01.2019)	**10 January 2019 (10.01.2019)**

Name and mailing address of the ISA/KR
International Application Division
Korean Intellectual Property Office
189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea
Facsimile No. +82-42-481-8578

Authorized officer
PARK, Tae Wook
Telephone No. +82-42-481-3405

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		EP 2495392 B1	30/08/2017
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		US 8170801 B2	01/05/2012
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WO 89-02579 A1	23/03/1989	None	
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		MX 2010005562 A	02/06/2010
		NO 20100695 A	15/06/2010
		US 8776591 B2	15/07/2014
		WO 2009-068302 A2	04/06/2009
		WO 2009-068302 A3	24/09/2009
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