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(71) Applicant *(for CA only)*: **SCHLUMBERGER CANADA LIMITED** [CA/CA]; 125 - 9 Avenue SE, Calgary, Alberta T2G 0P6 (CA).

(71) Applicant *(for FR only)*: **SERVICES PETROLIERS SCHLUMBERGER** [FR/FR]; 42 rue Saint Dominique, 75007 Paris (FR).

(71) Applicant *(for all designated States except CA, FR, US)*: **GEOQUEST SYSTEMS B.V.** [NL/NL]; Gevers Deynootweg 61, 2586 BJ The Hague (NL).

(71) Applicant *(for US only)*: **SCHLUMBERGER TECHNOLOGY CORPORATION** [US/US]; 300 Schlumberger Drive, Sugar Land, Texas 77478 (US).

(72) Inventor: **DIAZ CAMPOS, Mery**; 3030 Dunvale Rd. Apt 7310, Houston, Texas 77063 (US).

(74) Agents: **MCGINN, Alec J.** et al.; 10001 Richmond Avenue, IP Administration Center of Excellence, Room 4720, Houston, Texas 77042 (US).

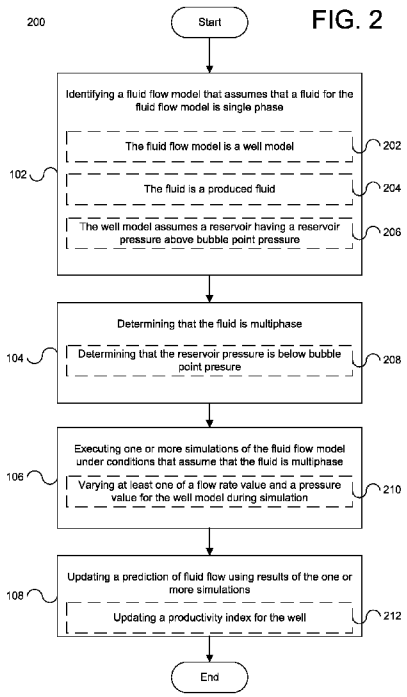
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[Continued on next page]

(54) Title: APPROACHES TO PREDICTING PRODUCTION OF MULTIPHASE FLUIDS

FIG. 2



(57) Abstract: Methods, computing systems, and computer-readable media for predicting multiphase fluid flow. The method may involve identifying a fluid flow model that assumes that the fluid is single phase and determining that the fluid is multiphase. The method may also involve executing simulations of the fluid flow model under conditions that assume that the fluid is multiphase and updating the prediction of the fluid flow using the results of the simulation.

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APPROACHES TO PREDICTING PRODUCTION OF MULTIPHASE FLUIDS

Cross Reference to Related Applications

[0001] This application claims priority under 35 U.S.C. § 119(e) to U.S. Provisional Patent Application Serial Number 62/103,271, filed on 14 January 2015 and entitled, "Approaches to Predicting Fluid Flow for Multiphase Fluids." U.S. Provisional Patent Application Serial Number 62/103,271 is incorporated herein by reference in its entirety.

Background

[0002] Fluid behavior may vary depending on how many phases the fluid has. Understanding fluid behavior can be valuable for approaches for recovering fluids, or other activities that involve fluid modeling. For example, inflow performance relationship (IPR) is a mathematical tool used in production engineering to assess well performance. The IPR plots the well production rate (the volume of produced fluid per unit of time) against the flowing bottom hole pressure (the pressure measured in a well at or near the depth of the producing formation). Generally, the data to measure the IPR is obtained by measuring the production rates under various drawdown pressures.

[0003] It can, however, be a challenge to obtain an accurate IPR for multiphase flow. When the reservoir pressure is below the bubble point pressure, the traditional straight-line productivity index is generally inaccurate. As a result, production engineers may lack confidence in the IPR plots that fail to account for the changes that result when the reservoir pressure is below the bubble point pressure. Production engineers may want data on flow and pressure conditions at the well to generate accurate IPRs. Such data may not be readily available, and the production engineer may be forced to forgo the benefits of an accurate IPR as a result.

[0004] Flow after flow well tests (also referred to as backpressure test or four-point test) can be used in the field to help determine the deliverability for a well. This method generally involves flowing a well at a selected constant rate until the pressure stabilizes. The stabilized rate and pressure are recorded, and the rate is changed and the well flowed again until the pressure stabilizes at the new rate. This process can be repeated at multiple rates and the results used to generate the IPR.

Summary

[0005] Embodiments of the present disclosure may provide methods, computing systems, and computer-readable media for predicting fluid flow for multiphase fluids. In some embodiments, the method involves identifying a fluid flow model that assumes that the fluid for the fluid flow model is single phase and determining that the fluid is multiphase. The method may involve executing multiple simulations of the fluid flow model under conditions that assume that the fluid is multiphase. The prediction of the fluid flow may then be updated using the results of simulations.

[0006] In some embodiments, a non-transitory computer-readable medium stores instructions for identifying a well for a reservoir with reservoir pressure below bubble point pressure. In response, the instructions may perform an inflow performance relationship (IPR) simulation on a well model of the well. The IPR simulation may involve executing a simulation at one flow rate, determining the bottom hole pressure at that flow rate, and executing another simulation at another flow rate and determining the bottom hole pressure at the new flow rate. An IPR metric may then be generated from the flow rates and the bottom hole pressures. Multiple additional simulations may be run to generate additional data points.

[0007] A system may include a reservoir simulator that predicts flow of fluids in a reservoir and a well model that represents a well for the reservoir. The system may also include a productivity index component that executes multiple simulations for the well model and, using the results, determines bottom hole pressure values and their associated flow rates. The productivity index component may generate a productivity index using the flow rates and the bottom hole pressure values.

[0008] The foregoing summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to comprehensively identify features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

Brief Description of the Drawings

[0009] The accompanying drawings, which are incorporated in and constitute a part of this specification, illustrate embodiments of the present teachings and together with the description, serve to explain the principles of the present teachings. In the figures:

[0010] Figure 1 illustrates a flowchart of a method for predicting fluid flow for multiphase liquids.

[0011] Figure 2 illustrates a flowchart of a method for creating a productivity index for a well producing multiphase fluid.

[0012] Figure 3 illustrates some embodiments of a system for creating a productivity index for a well.

[0013] Figure 4 illustrates a schematic view of a productivity index component.

[0014] Figure 5 illustrates a schematic view of a processor system.

Detailed Description

[0015] The following detailed description refers to the accompanying drawings. Wherever convenient, the same reference numbers are used in the drawings and the following description to refer to the same or similar parts. While several embodiments and features of the present disclosure are described herein, modifications, adaptations, and other implementations are possible, without departing from the spirit and scope of the present disclosure.

[0016] In general, embodiments of the present disclosure may provide systems, methods, and computer-readable media for predicting fluid flow for multiphase fluids. Figure 1 illustrates some embodiments of a method 100 for predicting fluid flow. The method 100 may begin with identifying 102 a fluid flow model that assumes that a fluid for the fluid flow model is single phase. In some embodiments, the fluid model may assume that the conditions for the fluid flow model (such as the temperature and pressure conditions) are such that the fluid is in a single phase state.

[0017] The method 100 may also involve determining 104 that the fluid is multiphase. In some embodiments, one or more conditions associated with the fluid flow model are monitored. The determination that the fluid is multiphase may be made in response to a change in the conditions from those associated with single phase for the fluid being modeled to conditions associated with multiphase. For example, at a particular temperature and pressure, the fluid may be in a single

phase state. An increase in temperature and pressure may result in the fluid changing to a multiphase state. In some embodiments, the fluid flow model corresponds to an actual structure with the fluid flowing in it. In such an embodiment, the conditions at the actual structure may be measured. In some embodiments, the composition of the fluid in the actual structure is measured.

[0018] The method 100 may also involve executing 106 one or more simulations of the fluid flow model under conditions that assume that the fluid is multiphase. In some embodiments, the simulation of the fluid flow model simulates flow of the fluid over a period of three to five days.

[0019] The method 100 may also involve updating 108 a prediction of fluid flow using the results of the one or more simulations. The prediction may be a graph or chart, a table, or some combination thereof. In some embodiments, the prediction predicts how changes in conditions for the fluid flow model may affect fluid recovery.

[0020] Figure 2 illustrates some embodiments of a method 200. The method 200 is an embodiment of an implementation of the method 100 in a well environment. The method 200 may begin with identifying 102 a fluid flow model that assumes that the fluid for the fluid flow model is single phase. In one embodiment, as indicated by numeral 202, the fluid flow model may be a well model. The well may be for extracting hydrocarbons such as oil and gas from a reservoir. The fluid, as indicated by numeral 204, may be a produced fluid such as oil, gas, water, or some combination thereof. The fluid flow model assuming that the fluid is single phase may be, in some embodiments indicated by numeral 206, a well model that assumes a reservoir having a reservoir pressure that is above bubble point pressure.

[0021] The method 200 may involve determining 104 that the fluid is multiphase. This determination may be made using measured data associated with the well and/or the reservoir. In another embodiment, this determination may be made using a simulation or predictions of conditions for the well and/or the reservoir.

[0022] In the embodiment of Figure 2, determining that the fluid is multiphase may involve determining 208 that the reservoir pressure is below the bubble point. The bubble point, in a hydrocarbon environment, refers to the pressure and temperature conditions at which the first bubble of gas comes out of solution in oil. The oil may be saturated with gas when discovered, meaning that the oil is holding all the gas it can at the reservoir temperature and pressure. The pressure at which the gas begins to evolve from the oil is the bubble point. Above bubble point, the pressure is high enough to prevent bubbles or gas from forming or entering the liquid phase.

Below the bubble point pressure, the pressure is sufficiently low to allow gas to enter, resulting in a multiphase (gas and liquid) fluid.

[0023] The method 200 may also involve executing one or more simulations of the fluid flow model under conditions that assume that the fluid is multiphase. In some embodiments, this involves varying 210 at least one of the flow rate value and the pressure value for the well model during simulation. For example, in some embodiments, a first simulation of the well model is executed at a constant flow rate, and the bottom hole pressure at that flow rate is determined. A second simulation of the well model may be executed at a different constant flow rate, and the bottom hole pressure associated with the new flow rate may be determined. This simulation process may be repeated at various different flow rates. In other embodiments, the bottom hole pressures may be set, and the simulations run to determine the associated flow rate.

[0024] The method may also involve updating 108 a prediction of fluid flow using the results of the one or more simulations. In some embodiments, this involves updating 212 a productivity index (often abbreviated as "PI") for the well associated with the well model. As used herein, the productivity index refers to an expression of the ability of a reservoir to deliver fluids to the wellbore.

[0025] Figure 3 illustrates some embodiments of a system 300. In the depicted embodiment, the system 300 includes a reservoir simulator 302, a well model 306, and a productivity index component 304. The reservoir simulator 302 simulates the flow of a fluid in a reservoir. Examples of reservoir simulators include ECLIPSE® and INTERSECT® offered by Schlumberger. The reservoir simulator 302 may include a computing device that includes computer models to predict the behavior of hydrocarbons in a reservoir. The reservoir simulator 302 may be used to aid in making production forecasts and the results may be used to help make investment decisions. The reservoir simulator 302 may also be used to identify opportunities to increase oil production, determine approaches to improve oil recovery, and other functions. The reservoir simulator 302 may have the ability to generate productivity curves for well models (such as well model 306) associated with the reservoir.

[0026] The system 300 may also include a well model 306. The well model 306 is a representation of an existing well, or a potential well, that is designed to bring hydrocarbons from a reservoir to the surface. The well model 306 may include various data values that

represent the existing well. The well model 306 may also include equations, relationships, and/or formula that indicate characteristics of the existing well based on the various data vales.

[0027] The system 300 may also include a productivity index component 304 for generating a productivity metric representing productivity of a particular well model 306. In some embodiments, the productivity index component 304 determines whether the fluid for a particular well model 306 is single phase or multiphase.

[0028] The productivity index model 304 may use various approaches to determining whether the fluid is single phase or multiphase. For example, the productivity index component 304 may make the determination using input from a user, such as an instruction to treat the fluid as multiphase. The productivity index component 304 may use actual data or predicted data about the conditions for the well component 306 to determine whether the fluid is single phase or multiphase. The productivity index component 304 may, for example, determine that the reservoir pressure for the reservoir is below bubble point pressure. The productivity index model 304 may determine that the produced fluid is single phase above the bubble point pressure. The productivity index model 304 may determine that the produced fluid is multiphase below the bubble point pressure.

[0029] The productivity index values may be revised to account for the change in phase. In some embodiments, the productivity index component 304 automatically monitors the conditions and generates the productivity index when the reservoir pressure for the reservoir falls below the bubble point pressure.

[0030] The productivity index component 304 may also execute simulations of the well model 306. In some embodiments, the productivity index component 304 invokes the reservoir simulator 302 to execute the simulations. The productivity index component 304 may vary one or more parameters for the simulations. For example, the productivity index component 304 may vary the flow rate or the bottom hole pressure (BHP) value for the well model 306.

[0031] In some embodiments, the productivity index component 304 executes between three and ten simulations. In another embodiment, it executes between three and four simulations. The productivity index component 304 may execute a first simulation at a first flow rate, a second simulation at a second flow rate, a third simulation at a third flow rate, and a fourth simulation at a fourth flow rate.

[0032] In some embodiments, the productivity index component 304 runs the first simulation and sets the first flow rate. The value for the first flow rate may be provided by a user, by another program, or selected by the productivity index component 304. The productivity index component 304 may specify a time period for the simulation; in some embodiments, a period of time of between one and five days is selected. The productivity index component 304 may run the first simulation and determine the stable bottom hole pressure (BHP) value for the well model 306 indicated by the first simulation. The productivity index component 304 may store the flow rate and the BHP for the first simulation in a data structure such as a table. The productivity index component 304 may run a second simulation at a different flow rate, determine the BHP value associated with the different flow rate, and save that information to the data structure.

[0033] The productivity index component 304 may also generate a productivity index using at least the plurality of flow rates and BHP values generated by the simulations. The productivity index may include an inflow performance relationship (IPR) metric. The IPR may help assess well performance by plotting the well production rate against the flowing BHP. The productivity index component 304 may update a previous productivity index with the productivity index created using the values from the simulation.

[0034] Figure 4 illustrates one embodiment of the productivity index component 304. The productivity index component 304, in the depicted embodiment, includes a phase component 402, a simulation component 404, a results component 406, and a calibration component 408. In some embodiments, the productivity index component 304 is implemented as instructions stored on a non-transitory computer-readable medium. The instructions may be executable by a processor.

[0035] The phase component 402 identifies one or more wells for reservoirs having reservoir pressure that has transitioned above or below bubble point pressure. The phase component 402 may monitor one or more conditions for the wells and/or the reservoir to determine the reservoir pressure. The phase component 402 may model conditions for the wells and/or reservoir to determine the reservoir pressure. The phase component 402 may receive input from a user indicating that the reservoir is below bubble point or that the phase component 402 should assume that the reservoir is below bubble point.

[0036] The productivity index component 304 may also include a simulation component 404 for performing an inflow performance relationship (IPR) simulation for a well. For example, the

simulation component 404 may model a flow after flow test. The results of the flow after flow test can be used to generate the IPR curves. The IPR simulation may involve executing a simulation of flow at a first flow rate and determining, from the simulation, the bottom hole pressure for the well at that flow rate. The simulation component 404 may iterate the simulation process with varying values for the flow rate of the bottom hole pressure. The simulation component 404 may set one of the values to be a constant, and determine the other value that corresponds with the constant.

[0037] In some embodiments, the simulation component 404 sets the flow rate to a constant and runs the simulation for a period of time. The simulation component 404 may perform a second simulation with a different constant flow rate value. The simulation component 404 may execute multiple simulations (serially or in parallel) and store the flow values and the corresponding pressures from the simulation at the set flow value.

[0038] The productivity index component 304 may also include a results component 406. The results component may generate an IPR metric using the flow rates and bottom hole pressures from the simulations run by the simulation component 404. In some embodiments, the IPR metric is a graph of an IPR curve. The IPR metric may also include a table of flow rates and bottom hole pressures. The table may be accessible to other software components and applications. In certain embodiments, the productivity index component 304 renders the IPR metric in a way that the user can read. For example, the IPR metric may be displayed as part of a report, on a dashboard associated with the well or the reservoir, as an alert, or other.

[0039] In some embodiments, the productivity index component 304 includes a calibration component 408. The calibration component may be used to calibrate the model used for the IPR simulation using a historical data set. The historical data set includes measured values from the well and reservoir being modeled. In some embodiments, the calibration component 408 executes a historical simulation (that is, a simulation run using the historical data) for the model. The calibration component 408 may then compare the historical simulation results data with measured historical data in the historical data set. For example, a historical data set may specify that an on-site well test, over a period of three days, revealed a bottom hole pressure x when the flow rate was y. The calibration component 408 may execute the simulation at the flow rate y for a period of three days and compare the bottom hole pressure value generated by the simulation with the bottom hole pressure x. If the simulation value for the bottom hole pressure is within a

specified range of the value *x*, the calibration component 408 may designate the two to match. In some embodiments, the calibration component 408 designates a match if the simulation value is no more than 5% different from the measured value.

[0040] In response to a mismatch between the historical simulation and the measured historical data, the calibration component 408 may change one or more parameters of the model. In certain embodiments, a user reviews the results to identify potential causes for the mismatch and, via the calibration component 408, adjusts the parameters. The calibration component 408 may run further simulations after the adjustments. The calibration component 408 may iterate over the simulation cycle, using historical data, until the simulations run using historical data matches the measured historical data. The calibration component 408 may deem the model to be accurate in response to the match.

[0041] While Figure 4 illustrates the calibration component 408 as a component of the productivity index 304, in other embodiments it may be a component of the reservoir simulator 302. Similarly, the phase component 402, simulation component 404, and results component 406 may be physically and/or logically separated from one another and implemented at various points in a system.

[0042] In certain embodiments, the calibration component 408 performs the calibration prior to the steps described in connection with Figures 1 and 2. In other embodiments, the calibration component 408 performs the calibration at regular intervals or in response to receiving new measured historical data. In such embodiments, the calibration component 408 may help ensure that the models remain valid.

[0043] The approaches described above may be repeated for those wells associated with a reservoir for which the reservoir pressure is below bubble point. This may allow the reservoir or production engineer to forgo conducting costly and timely flow-after-flow tests at an actual well. As a result, the costs associated with generating the tests may be significantly reduced, while allowing the benefits of the testing.

[0044] The productivity index component 304 may be configured to generate the IPR curves automatically in response to an input. The input may be an indicator that a fluid has transitioned from single phase to multiphase, that a well for a reservoir is below bubble point, that a user has selected an item (such as clicking a graphical user interface (GUI) element), or other input. In other embodiments, the productivity index component 304 generates the IPR curves

automatically without an input. For example, the productivity index component 304 may continuously update the IPR curves for display on a dashboard.

[0045] In certain embodiments, the productivity index component 304 may be configured to adjust one or more parameters or values associated with the well. The productivity index component 304 may, for example, adjust the flow rate at one or more places in the well in order to improve the performance of the well. In other embodiments, the productivity index component 304 provides recommendations to an engineer on how to improve performance in the well.

[0046] Embodiments of the disclosure may also include one or more systems for implementing one or more embodiments of the method for predicting fluid flow for multiphase fluids. Figure 5 illustrates a schematic view of such a computing or processor system 700, according to an embodiment. The processor system 700 may include one or more processors 702 of varying core configurations (including multiple cores) and clock frequencies. The one or more processors 702 may be operable to execute instructions, apply logic, etc. It will be appreciated that these functions may be provided by multiple processors or multiple cores on a single chip operating in parallel and/or communicably linked together. In at least some embodiments, the one or more processors 702 may be or include one or more GPUs.

[0047] The processor system 700 may also include a memory system, which may be or include one or more memory devices and/or computer-readable media 704 of varying physical dimensions, accessibility, storage capacities, etc. such as flash drives, hard drives, disks, random access memory, etc., for storing data, such as images, files, and program instructions for execution by the processor 702. In an embodiment, the computer-readable media 704 may store instructions that, when executed by the processor 702, are configured to cause the processor system 700 to perform operations. For example, execution of such instructions may cause the processor system 700 to implement one or more portions and/or embodiments of the method(s) described above.

[0048] The processor system 700 may also include one or more network interfaces 706. The network interfaces 706 may include any hardware, applications, and/or other software. Accordingly, the network interfaces 706 may include Ethernet adapters, wireless transceivers, PCI interfaces, and/or serial network components, for communicating over wired or wireless media using protocols, such as Ethernet, wireless Ethernet, etc.

[0049] As an example, the processor system 700 may be a mobile device that includes one or more network interfaces for communication of information. For example, a mobile device may include a wireless network interface (e.g., operable via one or more IEEE 802.11 protocols, ETSI GSM, BLUETOOTH®, satellite, etc.). As an example, a mobile device may include components such as a main processor, memory, a display, display graphics circuitry (e.g., optionally including touch and gesture circuitry), a SIM slot, audio/video circuitry, motion processing circuitry (e.g., accelerometer, gyroscope), wireless LAN circuitry, smart card circuitry, transmitter circuitry, GPS circuitry, and a battery. As an example, a mobile device may be configured as a cell phone, a tablet, etc. As an example, a method may be implemented (e.g., wholly or in part) using a mobile device. As an example, a system may include one or more mobile devices.

[0050] The processor system 700 may further include one or more peripheral interfaces 708, for communication with a display, projector, keyboards, mice, touchpads, sensors, other types of input and/or output peripherals, and/or the like. In some implementations, the components of processor system 700 may not be enclosed within a single enclosure or even located in close proximity to one another, but in other implementations, the components and/or others may be provided in a single enclosure. As an example, a system may be a distributed environment, for example, a so-called "cloud" environment where various devices, components, etc. interact for purposes of data storage, communications, computing, etc. As an example, a method may be implemented in a distributed environment (e.g., wholly or in part as a cloud-based service).

[0051] As an example, information may be input from a display (e.g., a touchscreen), output to a display or both. As an example, information may be output to a projector, a laser device, a printer, etc. such that the information may be viewed. As an example, information may be output stereographically or holographically. As to a printer, consider a 2D or a 3D printer. As an example, a 3D printer may include one or more substances that can be output to construct a 3D object. For example, data may be provided to a 3D printer to construct a 3D representation of a subterranean formation. As an example, layers may be constructed in 3D (e.g., horizons, etc.), geobodies constructed in 3D, etc. As an example, holes, fractures, etc., may be constructed in 3D (e.g., as positive structures, as negative structures, etc.).

[0052] The memory device 704 may be physically or logically arranged or configured to store data on one or more storage devices 710. The storage device 710 may include one or more file

systems or databases in any suitable format. The storage device 710 may also include one or more software programs 712, which may contain interpretable or executable instructions for performing one or more of the disclosed processes. When requested by the processor 702, one or more of the software programs 712, or a portion thereof, may be loaded from the storage devices 710 to the memory devices 704 for execution by the processor 702.

[0053] Those skilled in the art will appreciate that the above-described componentry is merely one example of a hardware configuration, as the processor system 700 may include any type of hardware components, including any accompanying firmware or software, for performing the disclosed implementations. The processor system 700 may also be implemented in part or in whole by electronic circuit components or processors, such as application-specific integrated circuits (ASICs) or field-programmable gate arrays (FPGAs).

[0054] The foregoing description of the present disclosure, along with its associated embodiments and examples, has been presented for purposes of illustration. It is not exhaustive and does not limit the present disclosure to the precise form disclosed. Those skilled in the art will appreciate from the foregoing description that modifications and variations are possible in light of the above teachings or may be acquired from practicing the disclosed embodiments.

[0055] For example, the same techniques described herein with reference to the processor system 700 may be used to execute programs according to instructions received from another program or from another processor system altogether. Similarly, commands may be received, executed, and their output returned entirely within the processing and/or memory of the processor system 700. Accordingly, the described embodiments may be performed without a visual interface command terminal or a terminal.

[0056] Likewise, the methods described may not be performed in the same sequence discussed or with the same degree of separation. Various aspects may be omitted, repeated, combined, or divided, as appropriate to achieve the same or similar objectives or enhancements. Accordingly, the present disclosure is not limited to the above-described embodiments, but instead is defined by the appended claims in light of their full scope of equivalents. Further, in the above description and in the below claims, unless specified otherwise, the term “execute” and its variants are to be interpreted as pertaining to any operation of program code or instructions on a device, whether compiled, interpreted, or run using other techniques. In the claims that follow, section 112 paragraph sixth is not invoked unless the phrase “means for” is used.

CLAIMS

What is claimed is:

1. A method for predicting fluid flow comprising:

identifying a fluid flow model that assumes that a fluid for the fluid flow model is single phase;

determining that the fluid is multiphase;

executing one or more simulations of the fluid flow model under conditions that assume that the fluid is multiphase; and

updating a prediction of fluid flow using results of the one or more simulations.

2. The method of claim 1, wherein the fluid flow model is a well model.

3. The method of claim 2, wherein:

the fluid is a produced fluid; and

the well model assumes a reservoir having a reservoir pressure above bubble point pressure.

4. The method of claim 3, wherein determining that the fluid is multiphase comprises determining that the reservoir pressure is below bubble point pressure.

5. The method of claim 3, wherein executing the one or more simulations further comprises varying at least one of a flow rate value and a pressure value for the well model during the one or more simulations.

6. The method of claim 3, wherein updating the prediction of fluid flow comprises updating a productivity index for the well.

7. A non-transitory computer-readable medium storing instructions that, when executed by a processor, cause the processor to perform operations, the operations comprising:

identifying a first well for a reservoir having a reservoir pressure below a bubble point pressure;

performing an inflow performance relationship (IPR) simulation for a first well model of the first well, the IPR simulation comprising:

executing a first simulation of flow at a first flow rate;

determining, from the first simulation, a first bottom hole pressure for the first well model at the first flow rate;

executing a second simulation of the flow at a second flow rate;

determining, from the second simulation, a second bottom hole pressure for the first well model at the second flow rate; and

generating an IPR metric using the first flow rate, the second flow rate, the first bottom hole pressure, and the second bottom hole pressure.

8. The non-transitory computer-readable medium of claim 7, further comprising, for the first well model:

executing a plurality of additional simulations of flow at a plurality of additional flow rates;

determining, from the plurality of additional simulations, a plurality of additional bottom hole pressures; and

generating the IPR metric using the first flow rate, the second flow rate, the plurality of additional flow rates, the first bottom hole pressure, the second bottom hole pressure, and the plurality of additional bottom hole pressures.

9. The non-transitory computer-readable medium of claim 7, further comprising performing a second IPR simulation for a second well model for the reservoir.

10. The non-transitory computer-readable medium of claim 7, wherein the IPR metric is graph of an IPR curve.

11. The non-transitory computer-readable medium of claim 10, the IPR metric further comprising a table.

12. The non-transitory computer-readable medium of claim 7, further comprising calibrating the first well model used for the IPR simulation using a historical data set.

13. The non-transitory computer-readable medium of claim 12, wherein calibrating the first well model comprises:

executing a historical simulation for the first well model;

comparing historical simulation results data with measured historical data; and

in response to a mismatch between the historical simulation results data and the measured historical data, changing one or more parameters of the first well model.

14. A system comprising:

a reservoir simulator that predicts flow of a fluid in a reservoir;

a well model representing a well for the reservoir;

a productivity index component configured to:

execute a plurality of simulations for the well model;

using results of the plurality of simulations, determine a plurality of bottom hole pressure values associated with a plurality of flow rates; and

generate a productivity index using at least the plurality of flow rates and the plurality of bottom hole pressure values.

15. The system of claim 14, the productivity index component further configured to, for each of the plurality of simulations, vary one of: flow rate; and bottom hole pressure.

16. The system of claim 14, wherein executing the plurality of simulations for the well model comprises:

executing a first simulation at a first flow rate;

executing a second simulation at a second flow rate;

executing a third simulation at a third flow rate; and

executing a fourth simulation at a fourth flow rate.

17. The system of claim 14, the productivity index component further configured to determine that a reservoir pressure for the reservoir is below a bubble point pressure.

18. The system of 17, the productivity index component further configured to automatically generate the productivity index in response to the reservoir pressure for the reservoir being below the bubble point pressure.

19. The system of claim 14, wherein the productivity index comprises an inflow performance relationship (IPR) metric.

20. The system of claim 14, the productivity index component further configured to update a previous productivity index with the productivity index.

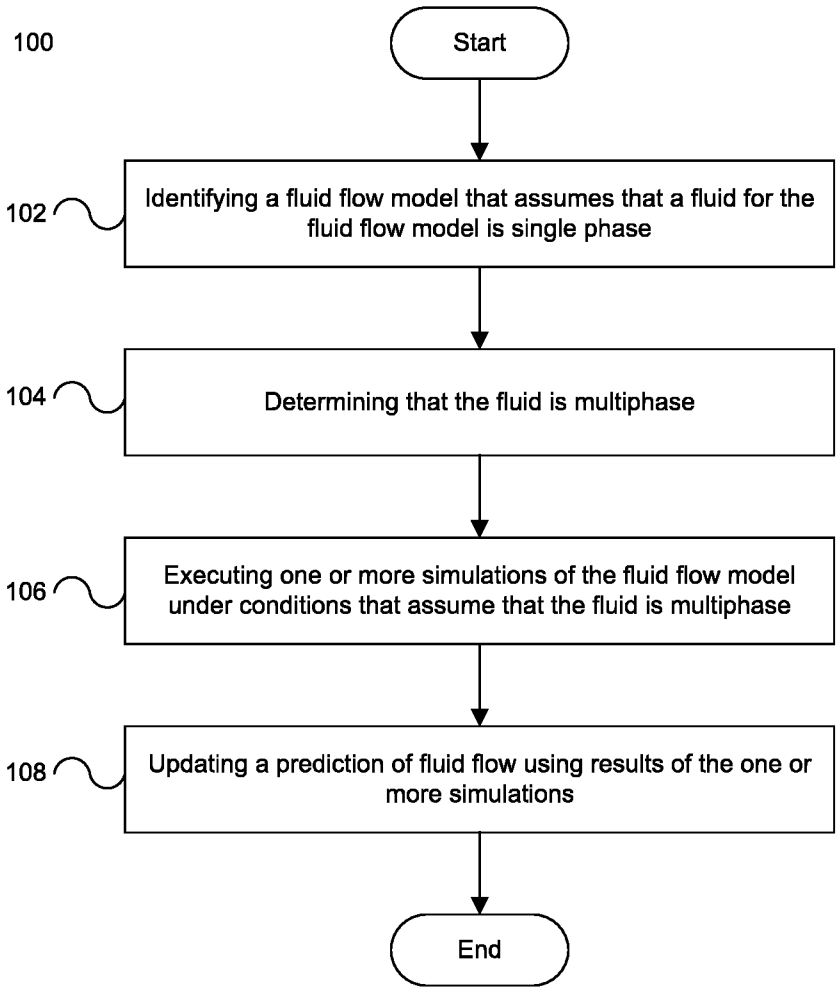

100
Start
102
Identifying a fluid flow model that assumes that a fluid for the fluid flow model is single phase
104
Determining that the fluid is multiphase
106
Executing one or more simulations of the fluid flow model under conditions that assume that the fluid is multiphase
108
Updating a prediction of fluid flow using results of the one or more simulations
End

FIG. 1

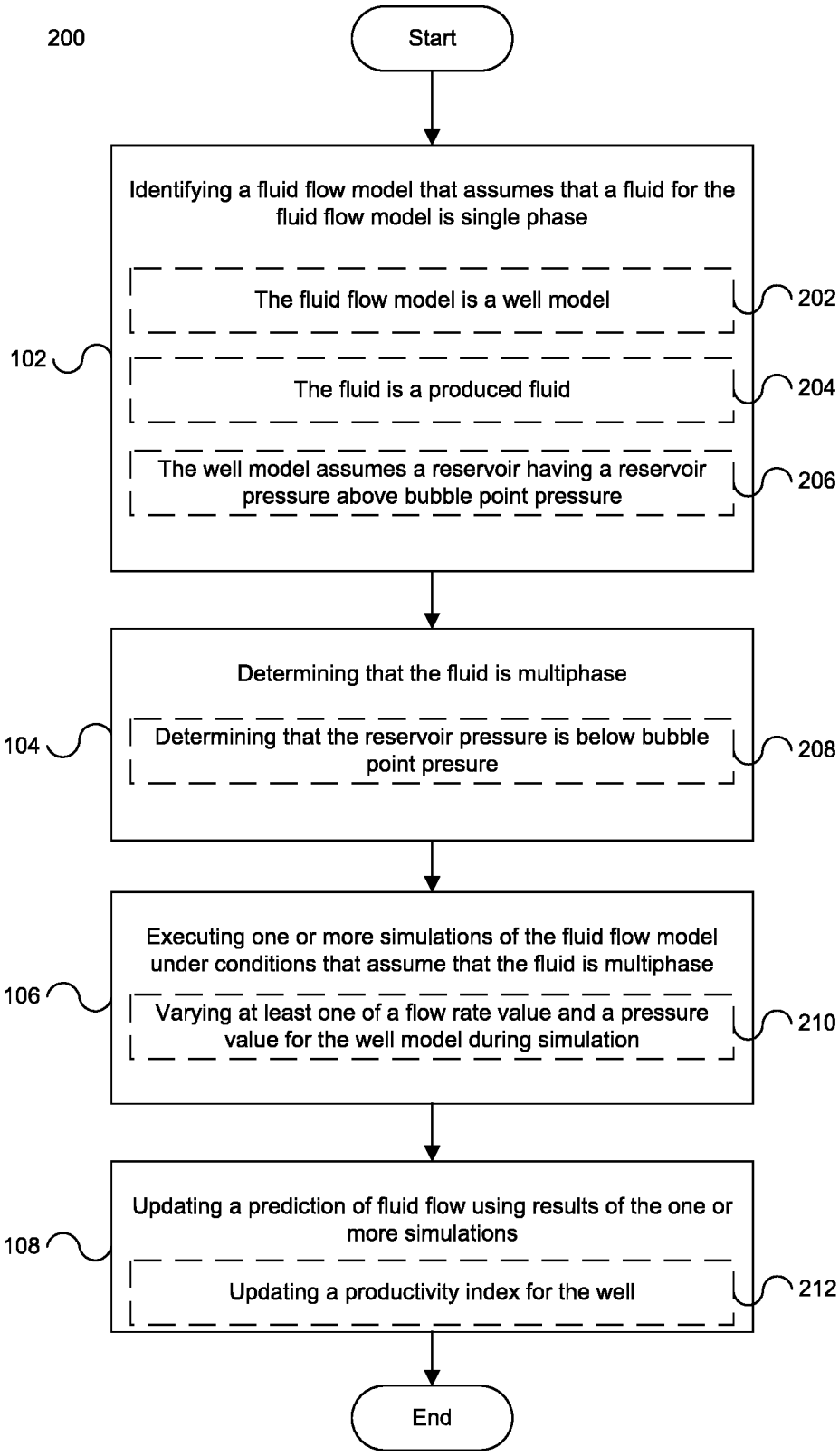

200
Start
Identifying a fluid flow model that assumes that a fluid for the fluid flow model is single phase
The fluid flow model is a well model
202
102
The fluid is a produced fluid
204
The well model assumes a reservoir having a reservoir pressure above bubble point pressure
206
Determining that the fluid is multiphase
104
Determining that the reservoir pressure is below bubble point presure
208
Executing one or more simulations of the fluid flow model under conditions that assume that the fluid is multiphase
106
Varying at least one of a flow rate value and a pressure value for the well model during simulation
210
Updating a prediction of fluid flow using results of the one or more simulations
108
Updating a productivity index for the well
212
End

FIG. 2

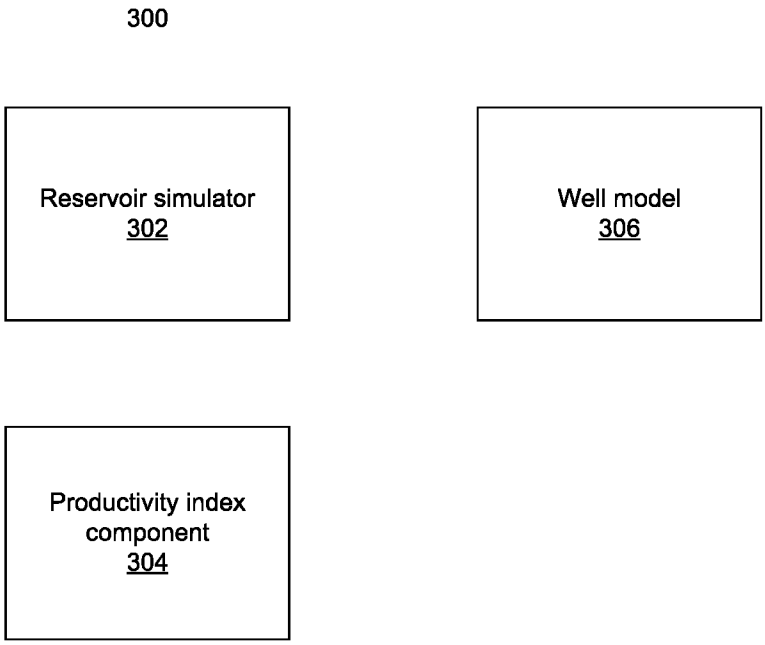

300
Reservoir simulator
302
Well model
306
Productivity index
component
304

FIG. 3

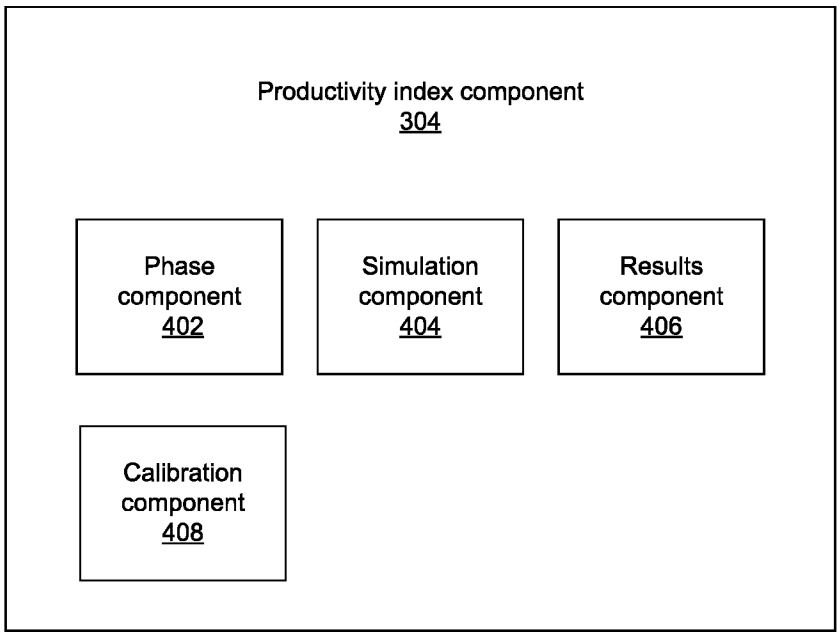

Productivity index component
304
Phase component
402
Simulation component
404
Results component
406
Calibration component
408

FIG. 4

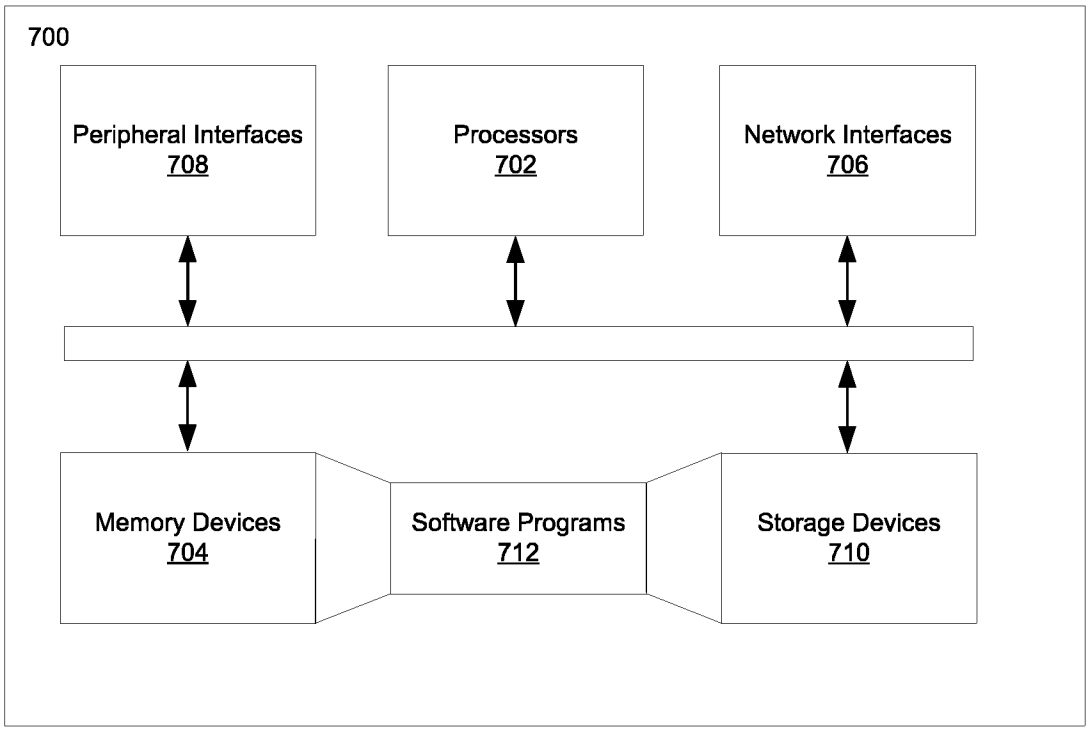

700
Peripheral Interfaces
708
Processors
702
Network Interfaces
706
Memory Devices
704
Software Programs
712
Storage Devices
710

FIG. 5

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/013339

A. CLASSIFICATION OF SUBJECT MATTER

G06Q 50/26(2012.01)i, G06Q 90/00(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)
G06Q 50/26; E21B 47/00; G06G 7/57; G06G 7/50; G06F 1900; G06Q 90/00

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: fluid, model, multiphase, simulations, update, bottom-hole, pressure, flow, rate, bubble-point, IPR, productivity

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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Y	US 2014-0136112 A1 (SAUDI ARABIAN OIL COMPANY) 15 May 2014 See abstract, paragraphs [0054],[0066]-[0068],[0071], claim 1 and figures 1-2,12-13.	1-20
A	US 6836731 B1 (ROBERT WHALLEY et al.) 28 December 2004 See abstract, claims 1,19 and figure 3.	1-20
A	US 2013-0035920 A1 (AHMAD TARIQ AL-SHAMMARI) 07 February 2013 See abstract, paragraphs [0076]-[0077],[0085]-[0086], claims 1-3 and figure 4.	1-20
A	US 2008-0133194 A1 (HANS ERIC KLUMPEN et al.) 05 June 2008 See abstract, paragraph [0096], claims 1-3 and figure 5.	1-20
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☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents:
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"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
25 April 2016 (25.04.2016)	**25 April 2016 (25.04.2016)**

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
LEE, Myung Jin
Telephone No. +82-42-481-8474

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/013339

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