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Klumpen et al.

(10) **Patent No.: US 8,352,227 B2**
(45) **Date of Patent: Jan. 8, 2013**

(54) **SYSTEM AND METHOD FOR PERFORMING OILFIELD SIMULATION OPERATIONS**

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(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 761 days.

(21) Appl. No.: **11/929,921**

(22) Filed: **Oct. 30, 2007**

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Related U.S. Application Data

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(51) **Int. Cl.**
G06G 7/48 (2006.01)

(52) **U.S. Cl.** **703/10**; 702/6

(58) **Field of Classification Search** 703/10; 702/6

See application file for complete search history.

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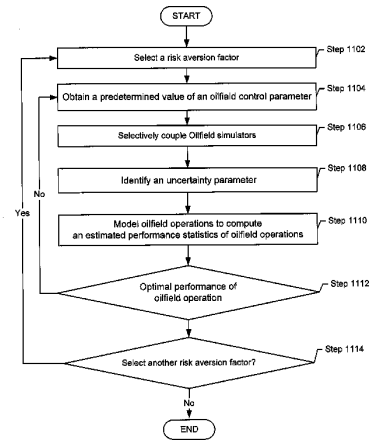
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(57) **ABSTRACT**

A method for performing operations of an oilfield is described. The method involves selectively coupling oilfield simulators according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, a first oilfield simulator receives an oilfield control parameter as an input, identifying an uncertainty parameter associated with probable values each corresponding to a weighted probability, a second oilfield simulator receives the uncertainty parameter as an input, modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the oilfield simulators, the operations of the oilfield are modeled with a predetermined value of the oilfield control parameter and at least one of the probable values of the uncertainty parameter; and identifying an optimal value of the oilfield control parameter based on the estimated performance.

19 Claims, 12 Drawing Sheets



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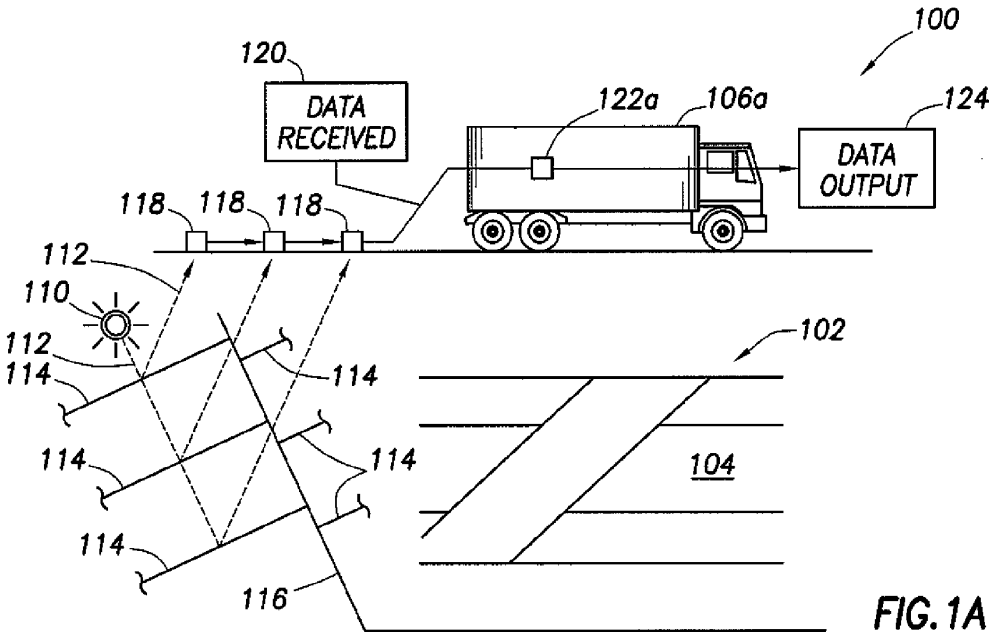

100
120
DATA RECEIVED
122a
106a
124
DATA OUTPUT
118
118
118
112
110
112
114
114
114
114
114
102
104
116

FIG. 1A

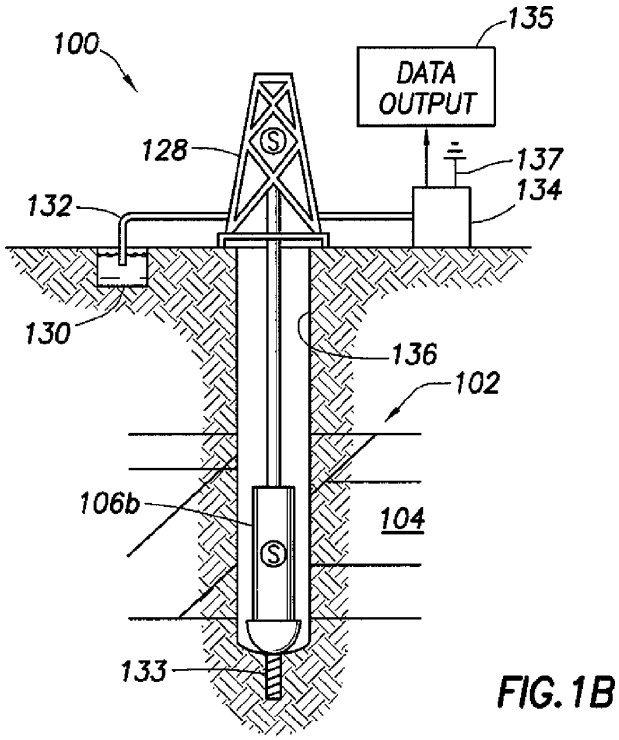

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135
DATA OUTPUT
128
137
134
132
130
136
102
106b
104
133

FIG. 1B

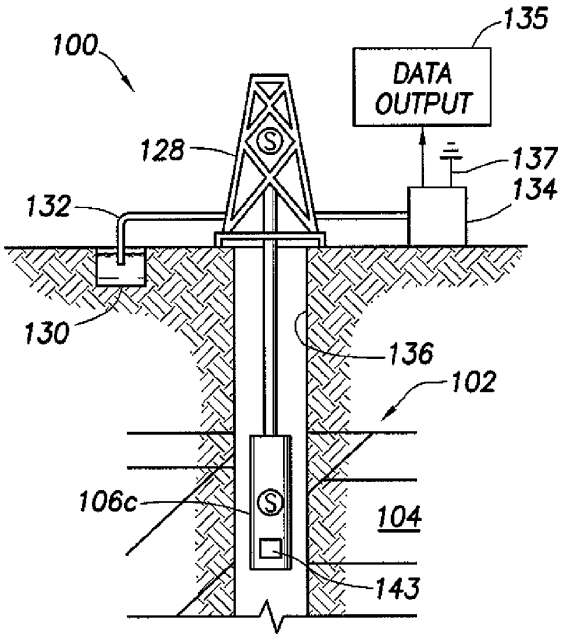

100
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DATA OUTPUT
128
137
134
132
130
136
102
106c
104
143

FIG. 1C

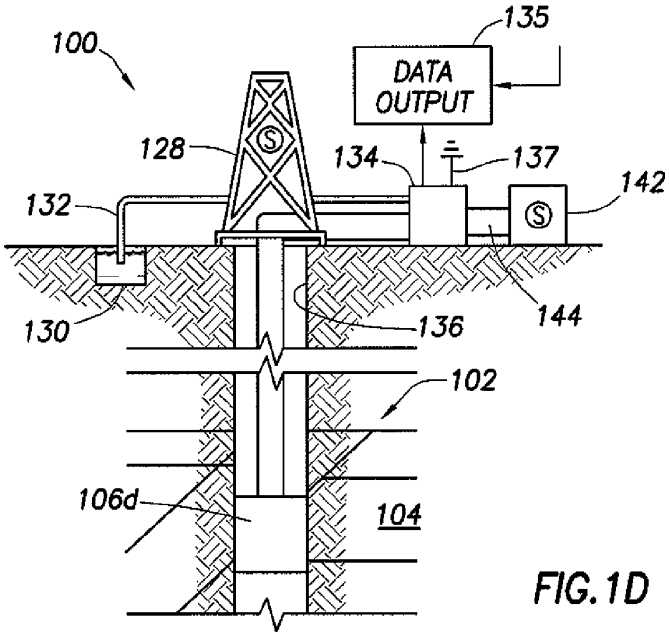

100
135
DATA OUTPUT
128
134
137
142
132
130
136
144
102
106d
104

FIG. 1D

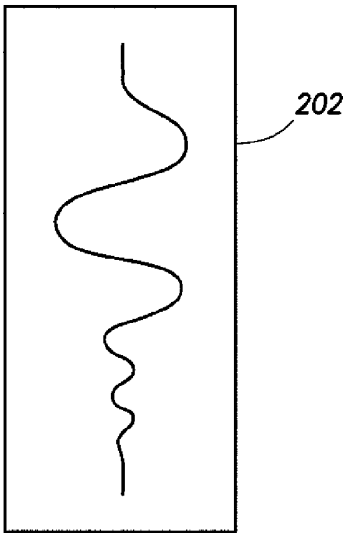


FIG.2A

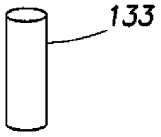


FIG.2B

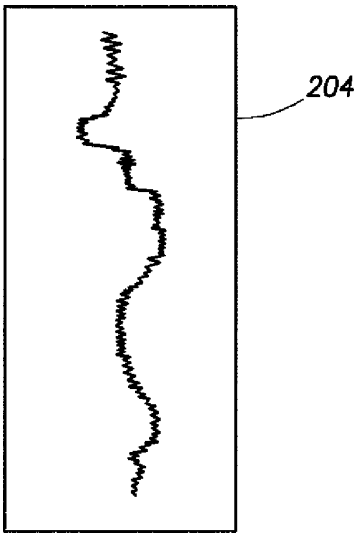


FIG.2C

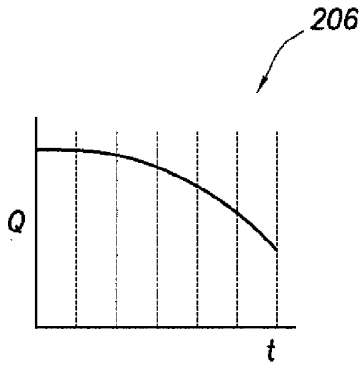


FIG.2D

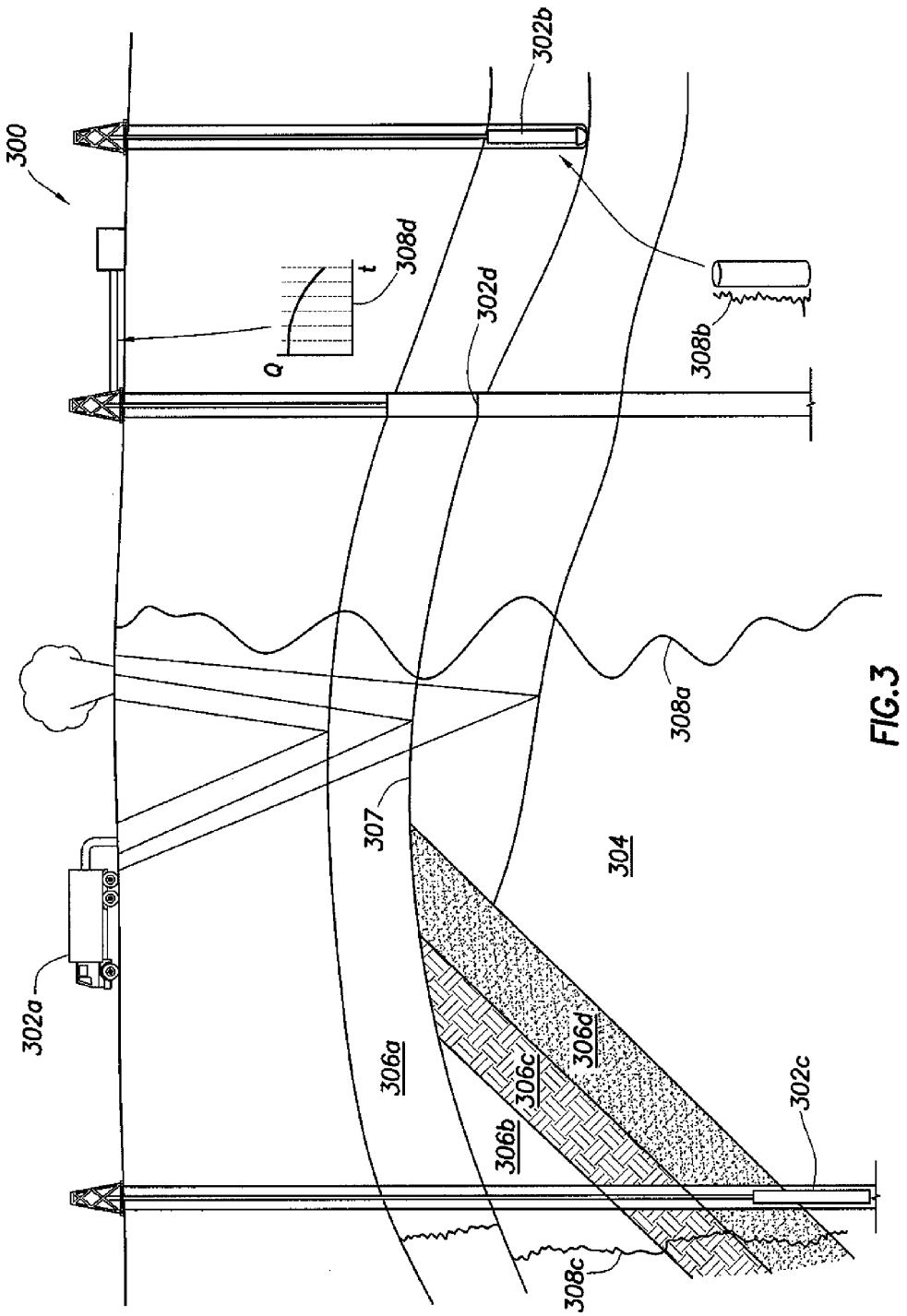

300
302b
308d
t
Q
302d
308b
308a
307
304
302a
306a
306d
306c
306b
302c
308c

FIG.3

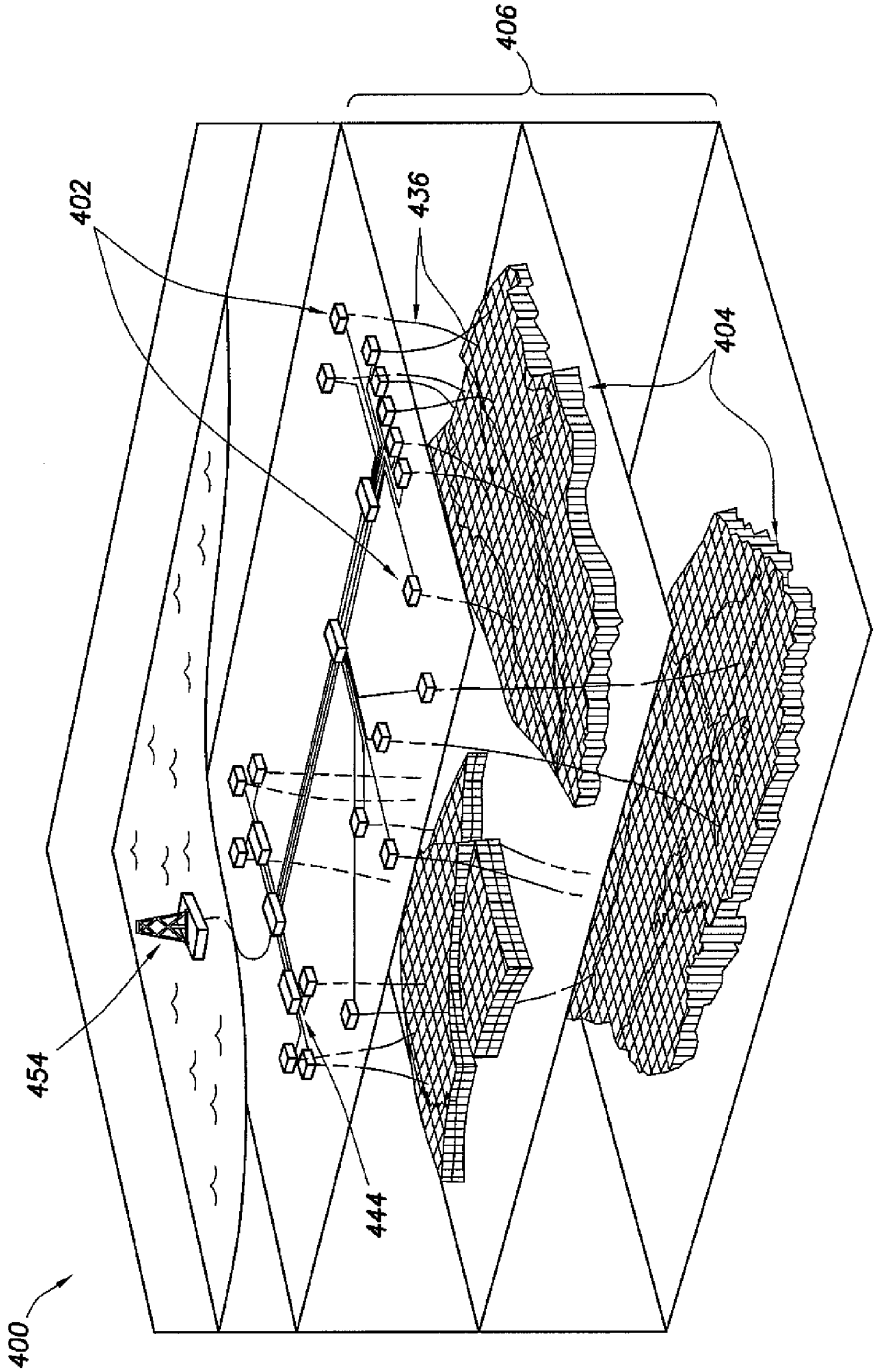


FIG. 4

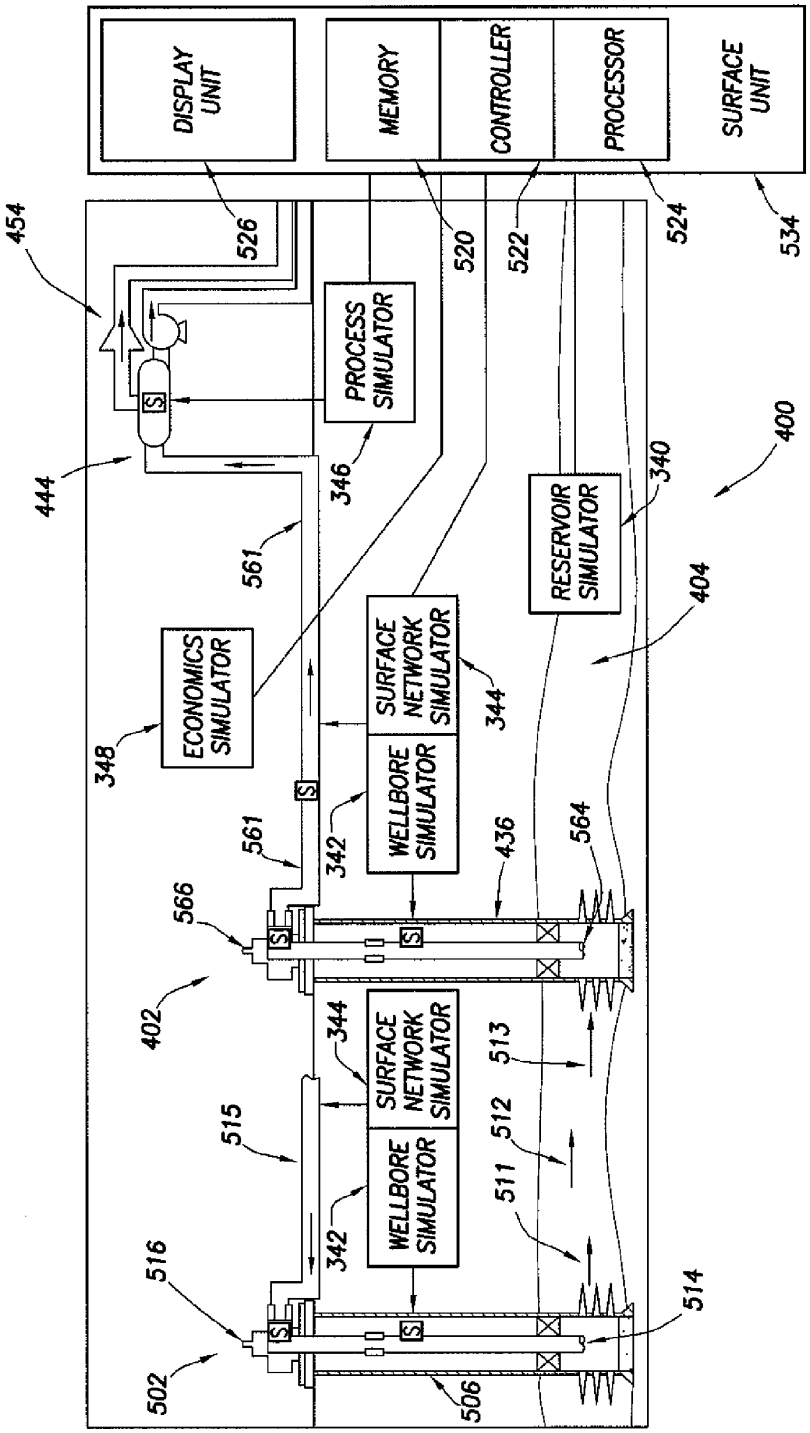

DISPLAY UNIT
MEMORY
CONTROLLER
PROCESSOR
SURFACE UNIT
526
520
522
524
534
454
444
PROCESS SIMULATOR
346
400
340
RESERVOIR SIMULATOR
404
561
ECONOMICS SIMULATOR
348
SURFACE NETWORK SIMULATOR
344
WELLBORE SIMULATOR
342
561
436
564
566
402
344
SURFACE NETWORK SIMULATOR
513
515
512
WELLBORE SIMULATOR
342
511
516
514
502
506

FIG.5

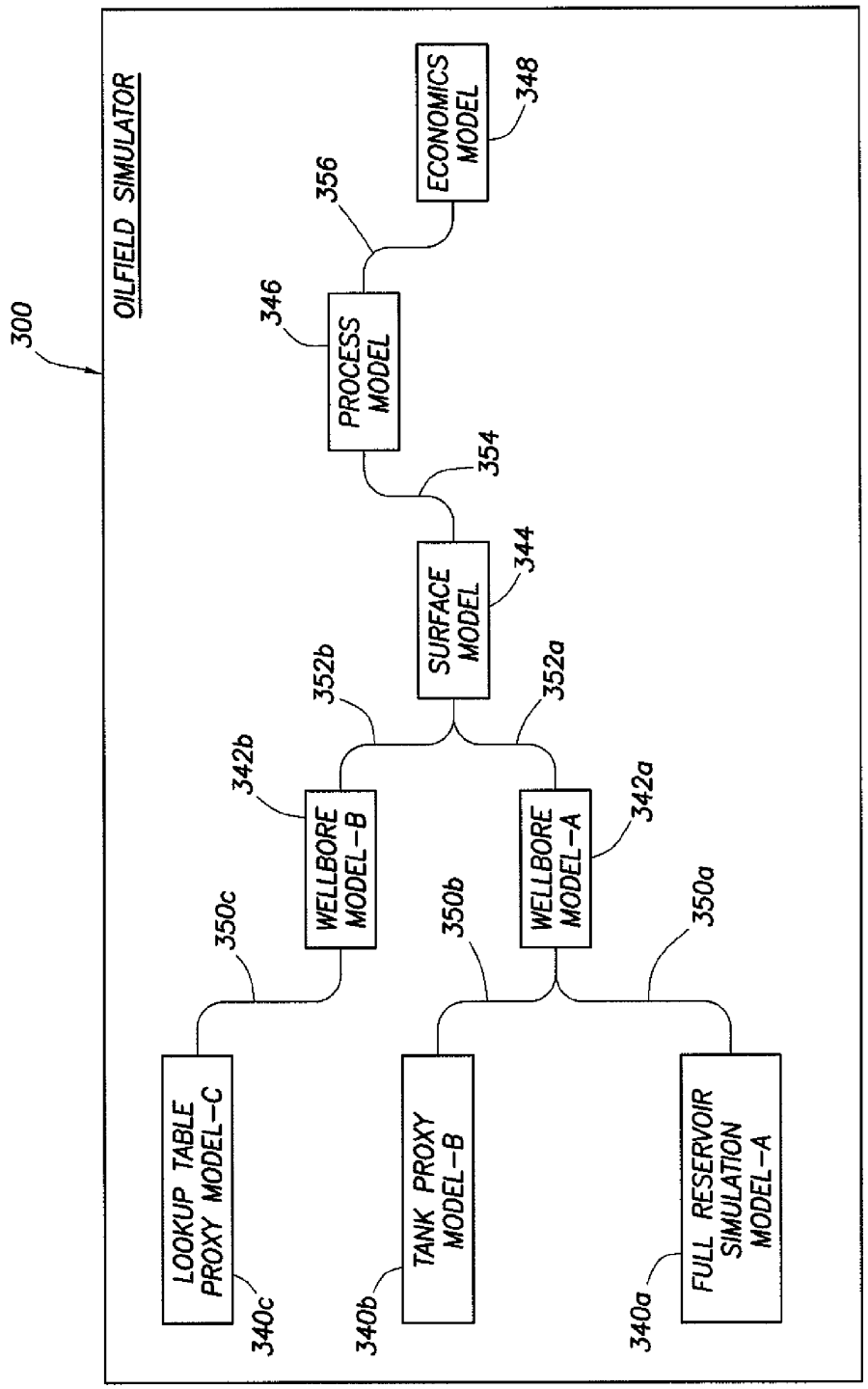

300
OILFIELD SIMULATOR
ECONOMICS MODEL
348
356
PROCESS MODEL
346
354
SURFACE MODEL
344
352b
352a
WELLBORE MODEL-B
342b
WELLBORE MODEL-A
342a
350c
350b
350a
LOOKUP TABLE PROXY MODEL-C
TANK PROXY MODEL-B
FULL RESERVOIR SIMULATION MODEL-A
340c
340b
340a

FIG. 6

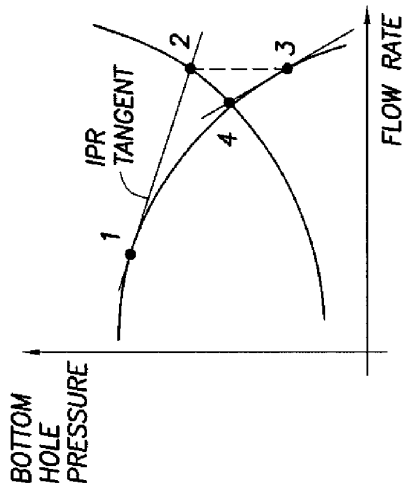


FIG.8

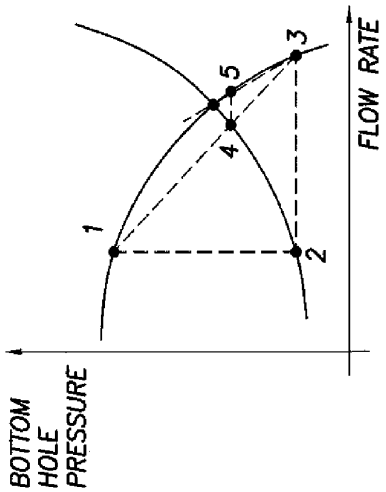


FIG.9A

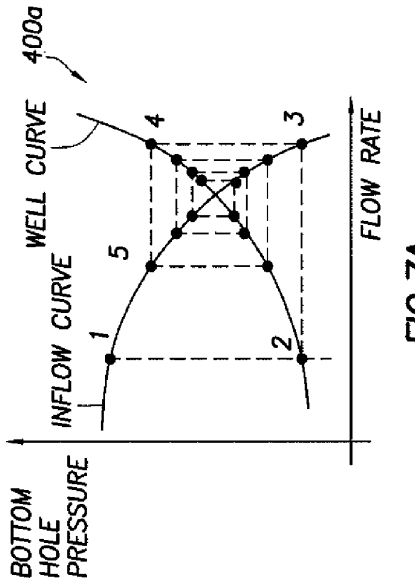


FIG.7A

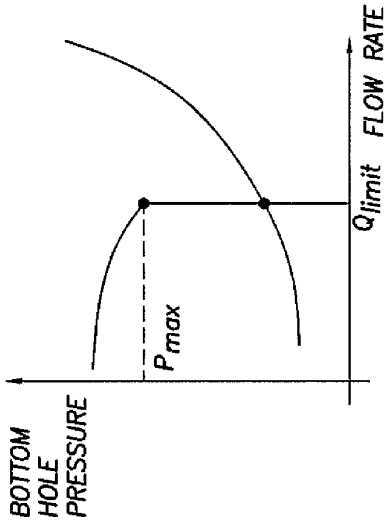


FIG.7B

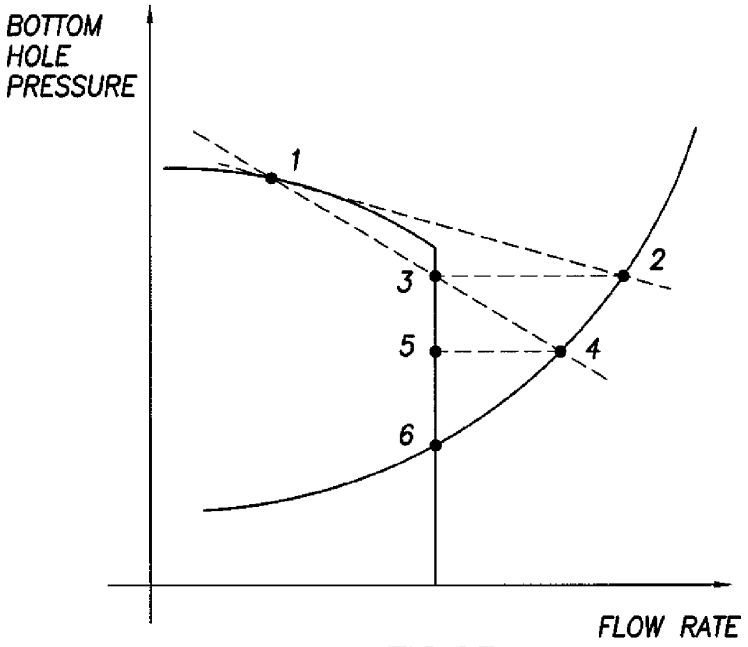

BOTTOM
HOLE
PRESSURE
1
2
3
4
5
6
FLOW RATE

FIG.9B

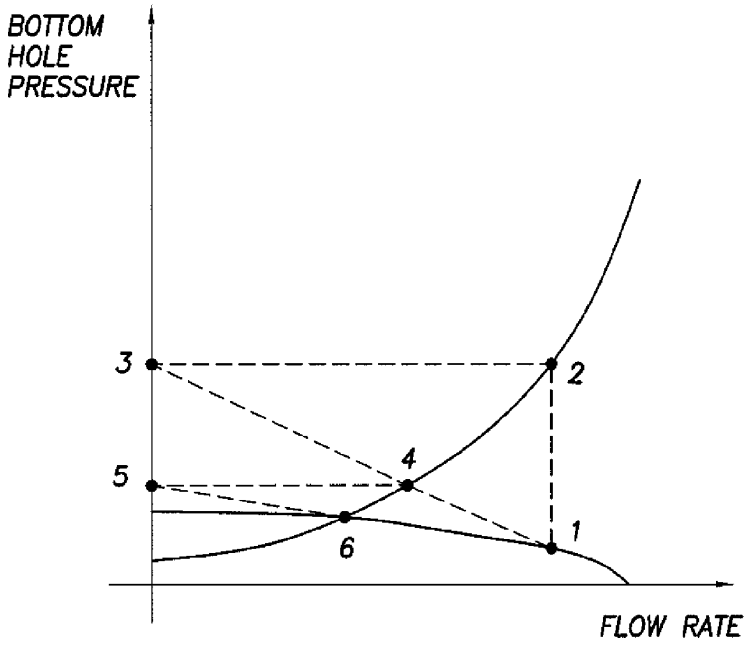
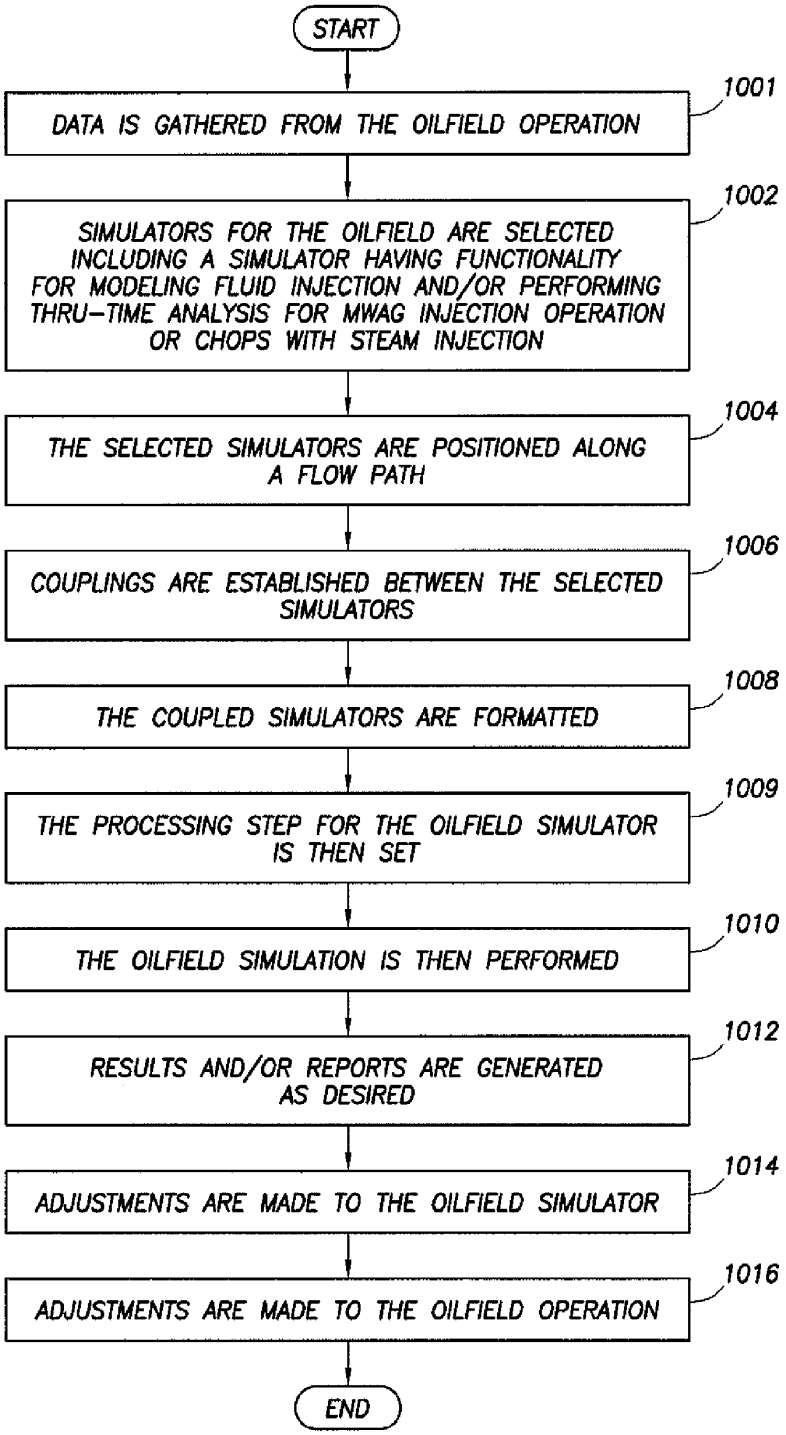

BOTTOM
HOLE
PRESSURE
3
2
4
5
1
6
FLOW RATE

FIG.9C

FIG. 10


START
DATA IS GATHERED FROM THE OILFIELD OPERATION
1001
SIMULATORS FOR THE OILFIELD ARE SELECTED INCLUDING A SIMULATOR HAVING FUNCTIONALITY FOR MODELING FLUID INJECTION AND/OR PERFORMING THRU-TIME ANALYSIS FOR MWAG INJECTION OPERATION OR CHOPS WITH STEAM INJECTION
1002
THE SELECTED SIMULATORS ARE POSITIONED ALONG A FLOW PATH
1004
COUPLINGS ARE ESTABLISHED BETWEEN THE SELECTED SIMULATORS
1006
THE COUPLED SIMULATORS ARE FORMATTED
1008
THE PROCESSING STEP FOR THE OILFIELD SIMULATOR IS THEN SET
1009
THE OILFIELD SIMULATION IS THEN PERFORMED
1010
RESULTS AND/OR REPORTS ARE GENERATED AS DESIRED
1012
ADJUSTMENTS ARE MADE TO THE OILFIELD SIMULATOR
1014
ADJUSTMENTS ARE MADE TO THE OILFIELD OPERATION
1016
END

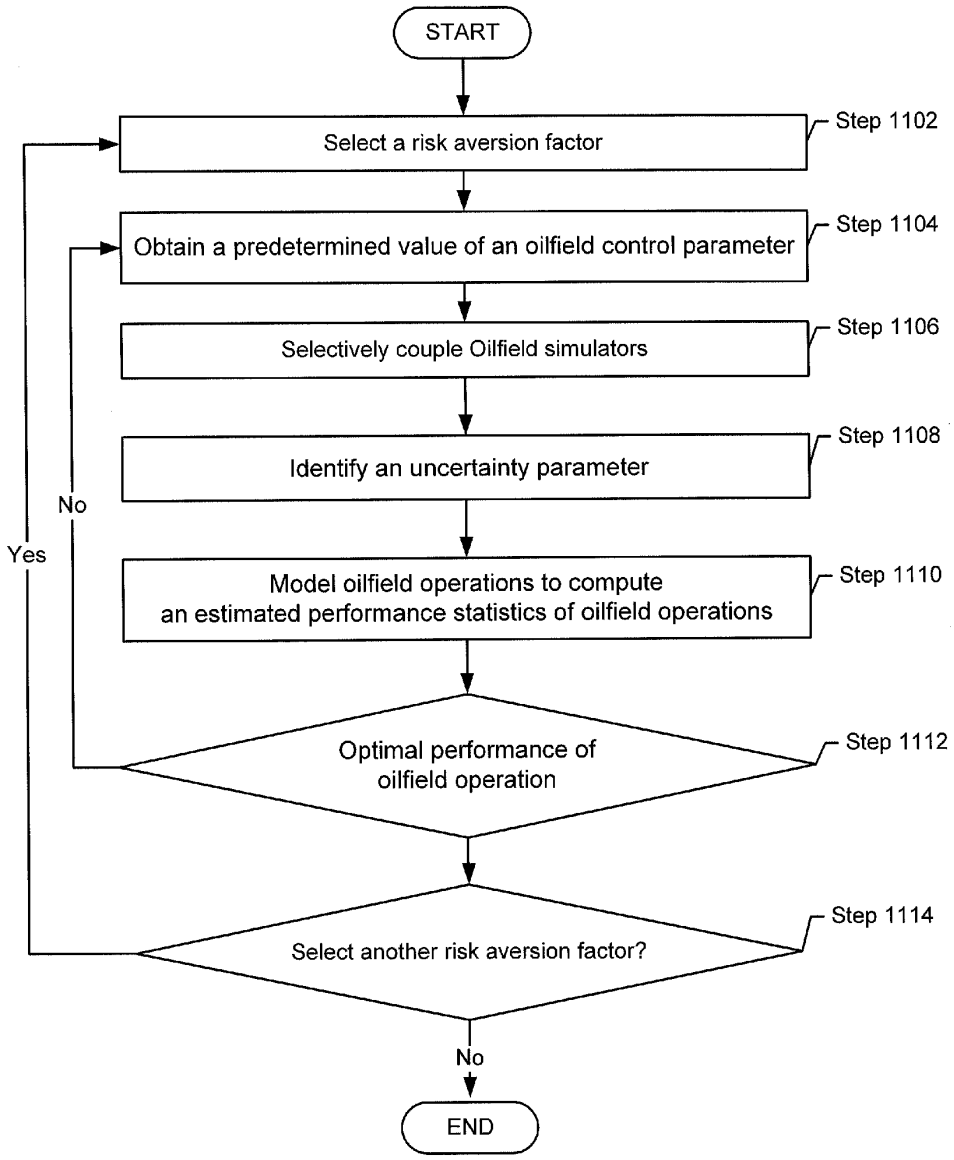

START
Select a risk aversion factor
Step 1102
Obtain a predetermined value of an oilfield control parameter
Step 1104
Selectively couple Oilfield simulators
Step 1106
Identify an uncertainty parameter
Step 1108
Model oilfield operations to compute an estimated performance statistics of oilfield operations
Step 1110
Optimal performance of oilfield operation
Step 1112
Select another risk aversion factor?
Step 1114
No
Yes
No
END

FIG. 11

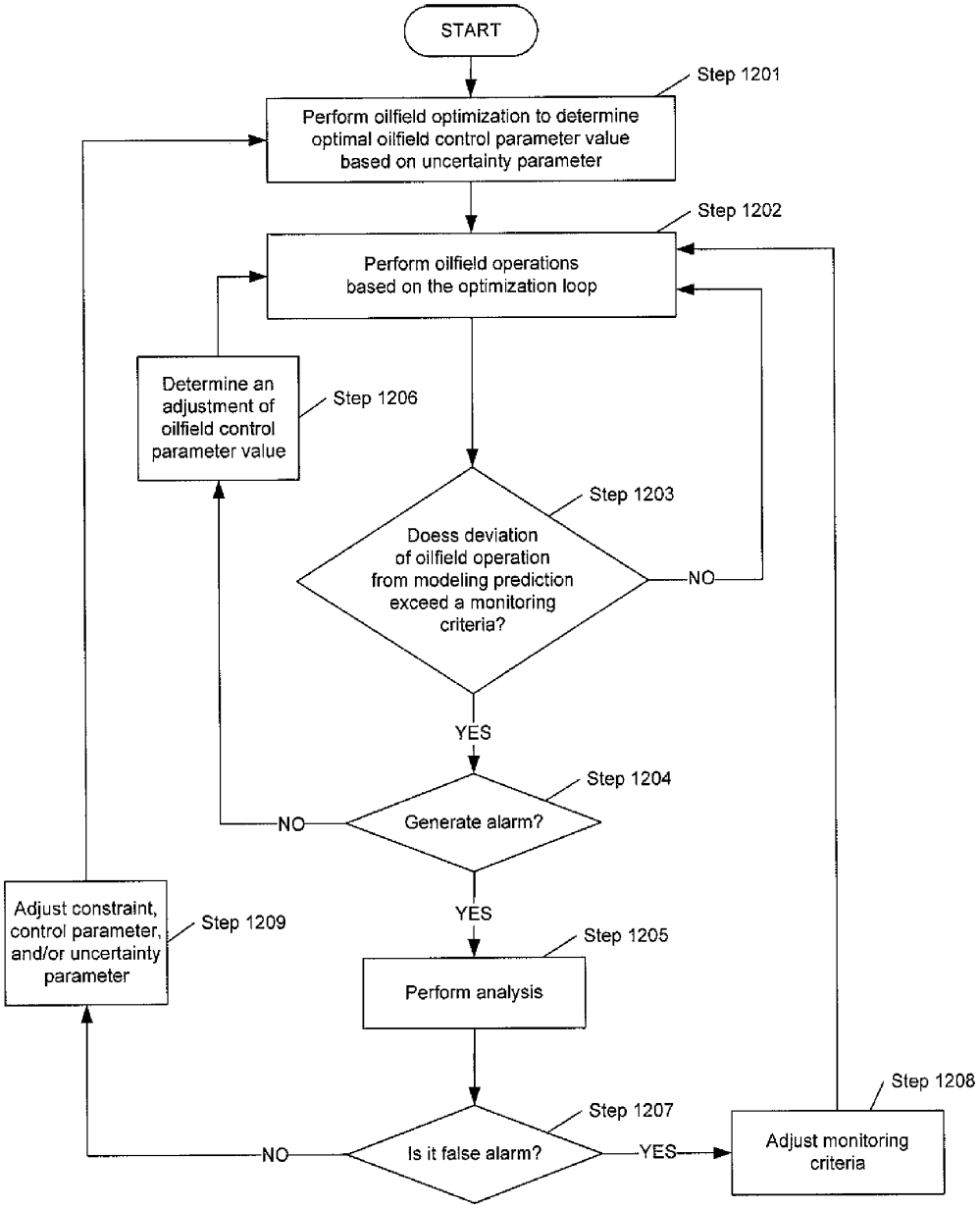

START
Step 1201
Perform oilfield optimization to determine optimal oilfield control parameter value based on uncertainty parameter
Step 1202
Perform oilfield operations based on the optimization loop
Determine an adjustment of oilfield control parameter value
Step 1206
Step 1203
Doess deviation of oilfield operation from modeling prediction exceed a monitoring criteria?
NO
YES
Step 1204
Generate alarm?
NO
YES
Adjust constraint, control parameter, and/or uncertainty parameter
Step 1209
Step 1205
Perform analysis
Step 1207
Is it false alarm?
NO
YES
Step 1208
Adjust monitoring criteria

FIGURE 12

SYSTEM AND METHOD FOR PERFORMING OILFIELD SIMULATION OPERATIONS

CROSS REFERENCE TO RELATED APPLICATIONS

This application claims priority under 35 U.S.C. §119 from Provisional Patent Application No. 60/855,262 filed Oct. 30, 2006, with a common inventor.

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention relates to techniques for optimizing oilfield operations relating to subterranean formations having reservoirs therein. More particularly, the invention relates to techniques for optimizing oilfield operations involving an analysis of reservoir operations, and their impact on such oilfield operations with deference to physical constraints present in any part of the petroleum production and fluid injection systems and with deference to reservoir and financial uncertainty.

2. Background of the Related Art

Oilfield operations, such as surveying, drilling, wireline testing, completions, simulation, planning and oilfield analysis, are typically performed to locate and gather valuable downhole fluids. Various aspects of the oilfield and its related operations are shown in FIGS. **1**A-**1**D. As shown in FIG. **1**A, surveys are often performed using acquisition methodologies, such as seismic scanners to generate maps of underground structures. These structures are often analyzed to determine the presence of subterranean assets, such as valuable fluids or minerals. This information is used to assess the underground structures and locate the formations containing the desired subterranean assets. Data collected from the acquisition methodologies may be evaluated and analyzed to determine whether such valuable items are present and if they are reasonably accessible.

As shown in FIG. **1**B-**1**D, one or more wellsites may be positioned along the underground structures to gather valuable fluids from the subterranean reservoirs. The wellsites are provided with tools capable of locating and removing hydrocarbons from the subterranean reservoirs. As shown in FIG. **1**B, drilling tools are typically advanced from the oil rigs and into the earth along a given path to locate the valuable downhole fluids. During the drilling operation, the drilling tool may perform downhole measurements to investigate downhole conditions. In some cases, as shown in FIG. **1**C, the drilling tool is removed and a wireline tool is deployed into the wellbore to perform additional downhole testing.

After the drilling operation is complete, the well may then be prepared for production. As shown in FIG. **1**D, wellbore completions equipment is deployed into the wellbore to complete the well in preparation for the production of fluid therethrough. Fluid is then drawn from downhole reservoirs, into the wellbore and flows to the surface. Production facilities are positioned at surface locations to collect the hydrocarbons from the wellsite(s). Fluid drawn from the subterranean reservoir(s) passes to the production facilities via transport mechanisms, such as tubing. Various equipment may be positioned about the oilfield to monitor oilfield parameters and/or to manipulate the oilfield operations.

During the oilfield operations, data is typically collected for analysis and/or monitoring of the oilfield operations. Such data may include, for example, subterranean formation, equipment, historical and/or other data. Data concerning the subterranean formation is collected using a variety of sources.

Such formation data may be static or dynamic. Static data relates to, for example, formation structure and geological stratigraphy that define the geological structure of the subterranean formation. Dynamic data relates to, for example, fluids flowing through the geologic structures of the subterranean formation over time. Such static and/or dynamic data may be collected to learn more about the formations and the valuable assets contained therein.

Sources used to collect static data may be seismic tools, such as a seismic truck that sends compression waves into the earth as shown in FIG. **1**A. These waves are measured to characterize changes in the density of the geological structure at different depths. This information may be used to generate basic structural maps of the subterranean formation. Other static measurements may be gathered using core sampling and well logging techniques. Core samples may be used to take physical specimens of the formation at various depths as shown in FIG. **1**B. Well logging typically involves deployment of a downhole tool into the wellbore to collect various downhole measurements, such as density, resistivity, etc., at various depths. Such well logging may be performed using, for example, the drilling tool of FIG. **1**B and/or the wireline tool of FIG. **1**C. Once the well is formed and completed, fluid flows to the surface using production tubing as shown in FIG. **1**D. As fluid passes to the surface, various dynamic measurements, such as fluid flow rates, pressure, and composition may be monitored. These parameters may be used to determine various characteristics of the subterranean formation.

Sensors may be positioned about the oilfield to collect data relating to various oilfield operations. For example, sensors in the drilling equipment may monitor drilling conditions, sensors in the wellbore may monitor fluid composition, sensors located along the flow path may monitor flow rates, and sensors at the processing facility may monitor fluids collected. Other sensors may be provided to monitor downhole, surface, equipment or other conditions. The monitored data is often used to make decisions at various locations of the oilfield at various times. Data collected by these sensors may be further analyzed and processed. Data may be collected and used for current or future operations. When used for future operations at the same or other locations, such data may sometimes be referred to as historical data.

The processed data may be used to predict downhole conditions, and make decisions concerning oilfield operations. Such decisions may involve well planning, well targeting, well completions, operating levels, production rates and other operations and/or conditions. Often this information is used to determine when to drill new wells, re-complete existing wells, or alter wellbore production.

Data from one or more wellbores may be analyzed to plan or predict various outcomes at a given wellbore. In some cases, the data from neighboring wellbores or wellbores with similar conditions or equipment may be used to predict how a well will perform. There are usually a large number of variables and large quantities of data to consider in analyzing oilfield operations. It is, therefore, often useful to model the behavior of the oilfield operation to determine the desired course of action. During the ongoing operations, the operating conditions may need adjustment as conditions change and new information is received.

Techniques have been developed to model the behavior of various aspects of the oilfield operations, such as geological structures, downhole reservoirs, wellbores, surface facilities as well as other portions of the oilfield operation. For example, U.S. Pat. No. 6,980,940 to Gurpinar discloses integrated reservoir optimization involving the assimilation of diverse data to optimize overall performance of a reservoir. In

another example, WO2004/049216 to Ghorayeb discloses an integrated modeling solution for coupling multiple reservoir simulations and surface facility networks. Other examples of these modeling techniques are shown in U.S. Pat. No 5,992,519, WO1999/064896, WO2005/122001, U.S. Pat. No. 6,313,837, US2003/0216897, US2003/0132934, US2005/0149307, US2006/0197759, US2004/0220846, and Ser. No. 10/586,283.

Techniques have also been developed to predict and/or plan certain oilfield operations, such as miscible water alternating gas (MWAG) injection operation. In an oilfield, initial production of the hydrocarbons is accomplished by "primary recovery" techniques wherein only the natural forces present in the reservoir are used to produce the hydrocarbons. However, upon depletion of these natural forces and the termination of primary recovery, a large portion of the hydrocarbons remains trapped within the reservoir. Also, many reservoirs lack sufficient natural forces to be produced by primary methods from the very beginning.

Recognition of these facts has led to the development and use of many enhanced oil recovery (EOR) techniques. Most of these techniques involve injection of at least one fluid into the reservoir to force hydrocarbons towards and into a production well. It is important that the fluid be injected carefully so that it forces the hydrocarbons toward the production well but does not prematurely reach the production well before all or most of the hydrocarbons have been produced.

Generally, once the fluid reaches the production well, production is adversely affected as the injected fluids are not generally sellable products and in some cases can be difficult to separate from the produced oil. Over the years, many have attempted to calculate the optimal pumping rates for injector wells and production wells to extract the most hydrocarbons from a reservoir. There is considerable uncertainty in a reservoir as to its geometry and geological parameters (e.g., porosity, rock permeabilities, etc.). In addition, the market value of hydrocarbons can vary dramatically and so financial factors may be important in determining how production should proceed to obtain the maximum value from the reservoir. Examples of techniques for modeling and/or planning MWAG injection operation are provided in U.S. Pat. No. 6,775,578.

Techniques have also been developed for performing reservoir simulation operations. See, for example, U.S. Pat. No. 6,230,101, U.S. Pat. No. 6,018,497, U.S. Pat. No. 6,078,869, GB2336008, U.S. Pat. No. 6,106,561, US2006/0184329, U.S. Pat. No. 7,164,990. Some simulation techniques involve the use of coupled simulations as described, for example, in Publication No. US2006/0129366.

Techniques have also been developed for performing optimization of reservoir operations with the intent to most economically produce the field. See, for example, U.S. Pat. No. 6,775,578.

Despite the development and advancement of reservoir simulation techniques in oilfield operations, there remains a need to provide techniques capable of modeling and implementing operations based on a complex analysis of a wide variety of parameters affecting oilfield operations. It is desirable that such a complex analysis of oilfield parameters gathered throughout the oilfield and their impact on the oilfield operations be performed considering reservoir uncertainty and/or financial uncertainty. It is further desirable that such techniques for modeling and/or optimizing oilfield operations be capable of one of more of the following, among others: optimizing objective functions such as net present value (NPV) of oilfield production based on levels of risk associated with the reservoir uncertainty and/or financial uncertainty, modeling the objective function based on estimated performance by performing concurrent simulation, selectively modeling oilfield operations based on more than one simulator; selectively merging data and/or outputs of more than one simulator; selectively merging data and/or outputs of simulators of one or more wellsites and/or oilfields; selectively linking a wide variety of simulators of like and/or different configurations; selectively linking simulators having similar and/or different applications and/or data models; selectively linking simulators of different members of an asset team of an oilfield; and providing coupling mechanisms capable of selectively linking simulators in a desired configuration.

SUMMARY OF THE INVENTION

In general, in one aspect, the invention relates to a method for performing operations of an oilfield having at least one process facilities and at least one wellsite operatively connected thereto, each at least one wellsite having a wellbore penetrating a subterranean formation for extracting fluid from or injecting fluid to an underground reservoir therein. The method comprising selectively coupling a plurality of oilfield simulators according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein a first oilfield simulator of the plurality of oilfield simulators receives an oilfield control parameter as an input; identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein a second oilfield simulator of the plurality of oilfield simulators receives the uncertainty parameter as an input; modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter; and identifying an optimal value of the oilfield control parameter based on the estimated performance.

In general, in one aspect, the invention relates to a method for performing operations of an oilfield having at least one process facilities and at least one wellsite operatively connected thereto, each at least one wellsite having a wellbore penetrating a subterranean formation for extracting fluid from or injecting fluid to an underground reservoir therein. The method comprising selectively coupling a plurality of oilfield simulators according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein a first oilfield simulator of the plurality of oilfield simulators receives an oilfield control parameter as an input; identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein a second oilfield simulator of the plurality of oilfield simulators receives the uncertainty parameter as an input; modeling the operations of the oilfield to generate a first estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a first predetermined value of the oilfield control parameter and a first probable value of the plurality of probable values of the uncertainty parameter; modeling the operations of the oilfield to generate a second estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a second predetermined value of the oilfield control parameter and a second probable value of the plurality of probable values of the uncertainty parameter; identifying an optimal value of the

oilfield control parameter by comparing the first estimated performance and the second estimated performance; and performing operations of the oilfield using the optimal value of the oilfield control parameter.

In general, in one aspect, the invention relates to a method for performing operations of an oilfield having at least one process facilities and at least one wellsite operatively connected thereto, each at least one wellsite having a wellbore penetrating a subterranean formation for extracting fluid from or injecting fluid to an underground reservoir therein. The method comprising selectively coupling a plurality of oilfield simulators according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein a first oilfield simulator of the plurality of oilfield simulators receives an oilfield control parameter as an input; identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein a second oilfield simulator of the plurality of oilfield simulators receives the uncertainty parameter as an input; modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter; identifying an optimal value of the oilfield control parameter based on the estimated performance; selecting a risk aversion factor represented by a parameterλ, wherein the estimated performance comprises a parameterized function Fλbased on the parameter λ, wherein the optimal value of the oilfield control parameter is a function of the parameterλ; determining a desired risk aversion factor based on Fλ; and performing the operations of the oilfield based on the desired risk aversion factor.

In general, in one aspect, the invention relates to a computer readable medium, embodying instructions executable by a computer to perform method steps for performing operations of an oilfield having a subterranean formation with at least one reservoir positioned therein. The instructions comprising functionality for selectively coupling a plurality of oilfield simulators according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein a first oilfield simulator of the plurality of oilfield simulators receives an oilfield control parameter as an input; identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein a second oilfield simulator of the plurality of oilfield simulators receives the uncertainty parameter as an input; modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter; and identifying an optimal value of the oilfield control parameter based on the estimated performance.

In general, in one aspect, the invention relates to a computer readable medium, embodying instructions executable by a computer to perform method steps for performing operations of an oilfield having a subterranean formation with at least one reservoir positioned therein. The instructions comprising functionality for selectively coupling a plurality of oilfield simulators according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein a first oilfield simulator of the plurality of oilfield simulators receives an oilfield control parameter as an input; identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein a second oilfield simulator of the plurality of oilfield simulators receives the uncertainty parameter as an input; modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter; identifying an optimal value of the oilfield control parameter based on the estimated performance; selecting a risk aversion factor represented by a parameterλ, wherein the estimated performance comprises a parameterized function Fλbased on the parameter λ, wherein the optimal value of the oilfield control parameter is a function of the parameterλ; determining a desired risk aversion factor based on Fλ, and performing the operations of the oilfield based on the desired risk aversion factor.

BRIEF DESCRIPTION OF THE DRAWINGS

So that the above recited features and advantages of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to the embodiments thereof that are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

FIGS. **1**A-**1**D show exemplary schematic views of an oilfield having subterranean structures including reservoirs therein and various oilfield operations being performed on the oilfield. FIG. **1**A depicts an exemplary survey operation being performed by a seismic truck. FIG. **1**B depicts an exemplary drilling operation being performed by a drilling tool suspended by a rig and advanced into the subterranean formation. FIG. **1**C depicts an exemplary wireline operation being performed by a wireline tool suspended by the rig and into the wellbore of FIG. **1**B. FIG. **1**D depicts an exemplary simulation operation being performed by a simulation tool being deployed from the rig and into a completed wellbore for drawing fluid from the downhole reservoir into a surface facility.

FIGS. **2**A-**2**D are exemplary graphical depictions of data collected by the tools of FIGS. **1**A-**1**D, respectively. FIG. **2**A depicts an exemplary seismic trace of the subterranean formation of FIG. **1**A. FIG. **2**B depicts exemplary core sample of the formation shown in FIG. **1**B. FIG. **2**C depicts an exemplary well log of the subterranean formation of FIG. **1**C. FIG. **2**D depicts an exemplary simulation decline curve of fluid flowing through the subterranean formation of FIG. **1**D.

FIG. **3** shows an exemplary schematic view, partially in cross section, of an oilfield having a plurality of data acquisition tools positioned at various locations along the oilfield for collecting data from the subterranean formation.

FIG. **4** shows an exemplary schematic view of an oilfield having a plurality of wellsites for producing hydrocarbons from the subterranean formation.

FIG. **5** shows an exemplary schematic diagram of a portion of the oilfield of FIG. **4** depicting the simulation operation in detail.

FIG. **6** is a schematic view of an oilfield simulator for the oilfield of FIG. **4**, the oilfield simulator having wellsite and non-wellsite simulators selectively coupled together to perform an oilfield simulation.

FIGS. **7**A and **7**B are graphs depicting rate-based coupling that may be used in the oilfield simulator of FIG. **6**. FIG. **7**A depicts an unconstrained rate-based coupling. FIG. **7**B depicts a reservoir constrained rate-based coupling.

FIG. **8** is a graph depicting a fast PI coupling that may be used in the oilfield simulator of FIG. **6**.

FIGS. **9**A, **9**B, and **9**C are graphs depicting a chord slope coupling that may be used in the oilfield simulator of FIG. **6**. FIG. **9**A depicts a network constrained well. FIG. **9**B depicts a reservoir constrained well. FIG. **9**C depicts a reservoir with reduced pressure.

FIG. **10** is a flowchart depicting a method of producing fluid from the oilfield of FIG. **1**.

FIG. **11** is a flowchart depicting a method for optimizing the oilfield operation.

FIG. **12** is a flowchart depicting a method for managing the oilfield operation based on the optimization of FIG. **11**.

DETAILED DESCRIPTION OF THE INVENTION

Presently preferred embodiments of the invention are shown in the above-identified figures and described in detail below. In describing the preferred embodiments, like or identical reference numerals are used to identify common or similar elements. The figures are not necessarily to scale and certain features and certain views of the figures may be shown exaggerated in scale or in schematic in the interest of clarity and conciseness.

FIGS. **1**A-D show an oilfield (**100**) having geological structures and/or subterranean formations therein. As shown in these figures, various measurements of the subterranean formation are taken by different tools at the same location. These measurements may be used to generate information about the formation and/or the geological structures and/or fluids contained therein.

FIGS. **1**A-**1**D depict schematic views of an oilfield (**100**) having subterranean formations (**102**) containing a reservoir (**104**) therein and depicting various oilfield operations being performed on the oilfield (**100**). FIG. **1**A depicts a survey operation being performed by a seismic truck (**106***a*) to measure properties of the subterranean formation. The survey operation is a seismic survey operation for producing sound vibration(s) (**112**). In FIG. **1**A, one such sound vibration (**112**) is generated by a source (**110**) and reflects off a plurality of horizons (**114**) in an earth formation (**116**). The sound vibration(s) (**112**) is (are) received in by sensors (S), such as geophone-receivers (**118**), situated on the earth's surface, and the geophone-receivers (**118**) produce electrical output signals, referred to as data received (**120**) in FIG. **1**.

In response to the received sound vibration(s) (**112**) representative of different parameters (such as amplitude and/or frequency) of the sound vibration(s) (**112**). The data received (**120**) is provided as input data to a computer (**122***a*) of the seismic recording truck (**106***a*), and responsive to the input data, the recording truck computer (**122***a*) generates a seismic data output record (**124**). The seismic data may be further processed as desired, for example by data reduction.

FIG. **1**B depicts a drilling operation being performed by a drilling tool (**106***b*) suspended by a rig (**128**) and advanced into the subterranean formation (**102**) to form a wellbore (**136**). A mud pit (**130**) is used to draw drilling mud into the drilling tool (**106***b*) via flow line (**132**) for circulating drilling mud through the drilling tool (**106***b*) and back to the surface. The drilling tool (**106***b*) is advanced into the formation to reach reservoir (**104**). The drilling tool (**106***b*) is preferably adapted for measuring downhole properties. The drilling tool (**106***b*) may also be adapted for taking a core sample (**133**) as shown, or removed so that a core sample (**133**) may be taken using another tool.

A surface unit (**134**) is used to communicate with the drilling tool (**106***b*) and offsite operations. The surface unit (**134**) is capable of communicating with the drilling tool (**106***b*) to send commands to drive the drilling tool (**106***b*), and to receive data therefrom. The surface unit (**134**) is preferably provided with computer facilities for receiving, storing, processing, and analyzing data from the oilfield (**100**). The surface unit (**134**) collects data output (**135**) generated during the drilling operation. Computer facilities, such as those of the surface unit (**134**), may be positioned at various locations about the oilfield (**100**) and/or at remote locations.

Sensors (S), such as gauges, may be positioned throughout the reservoir, rig, oilfield equipment (such as the downhole tool), or other portions of the oilfield for gathering information about various parameters, such as surface parameters, downhole parameters, and/or operating conditions. These sensors (S) preferably measure oilfield parameters, such as weight on bit, torque on bit, pressures, temperatures, flow rates, compositions and other parameters of the oilfield operation.

The information gathered by the sensors (S) may be collected by the surface unit (**134**) and/or other data collection sources for analysis or other processing. The data collected by the sensors (S) may be used alone or in combination with other data. The data may be collected in a database and all or select portions of the data may be selectively used for analyzing and/or predicting oilfield operations of the current and/or other wellbores.

Data outputs from the various sensors (S) positioned about the oilfield may be processed for use. The data may be historical data, real time data, or combinations thereof. The real time data may be used in real time, or stored for later use. The data may also be combined with historical data or other inputs for further analysis. The data may be housed in separate databases, or combined into a single database.

The collected data may be used to perform analysis, such as modeling operations. For example, the seismic data output may be used to perform geological, geophysical, reservoir engineering, and/or production simulations. The reservoir, wellbore, surface and/or process data may be used to perform reservoir, wellbore, or other production simulations. The data outputs from the oilfield operation may be generated directly from the sensors (S), or after some preprocessing or modeling. These data outputs may act as inputs for further analysis.

The data is collected and stored at the surface unit (**134**). One or more surface units (**134**) may be located at the oilfield (**100**), or linked remotely thereto. The surface unit (**134**) may be a single unit, or a complex network of units used to perform the necessary data management functions throughout the oilfield (**100**). The surface unit (**134**) may be a manual or automatic system. The surface unit (**134**) may be operated and/or adjusted by a user.

The surface unit (**134**) may be provided with a transceiver (**137**) to allow communications between the surface unit (**134**) and various portions of the oilfield (**100**) or other locations. The surface unit (**134**) may also be provided with or functionally linked to a controller for actuating mechanisms at the oilfield (**100**). The surface unit (**134**) may then send command signals to the oilfield (**100**) in response to data received. The surface unit (**134**) may receive commands via the transceiver or may itself execute commands to the controller. A processor may be provided to analyze the data (locally or remotely) and make the decisions to actuate the controller. In this manner, the oilfield (**100**) may be selec-

tively adjusted based on the data collected to optimize fluid recovery rates, or to maximize the longevity of the reservoir and its ultimate production capacity. These adjustments may be made automatically based on computer protocol, or manually by an operator. In some cases, well plans may be adjusted to select optimum operating conditions, or to avoid problems.

FIG. **1**C depicts a wireline operation being performed by a wireline tool (**106***c*) suspended by the rig (**128**) and into the wellbore (**136**) of FIG. **1**B. The wireline tool (**106***c*) is preferably adapted for deployment into a wellbore (**136**) for performing well logs, performing downhole tests and/or collecting samples. The wireline tool (**106***c*) may be used to provide another method and apparatus for performing a seismic survey operation. The wireline tool (**106***c*) of FIG. **1**C may have an explosive or acoustic energy source (**143**) that provides electrical signals to the surrounding subterranean formations (**102**).

The wireline tool (**106***c*) may be operatively linked to, for example, the geophones (**118**) stored in the computer (**122***a*) of the seismic recording truck (**106***a*) of FIG. **1**A. The wireline tool (**106***c*) may also provide data to the surface unit (**134**). As shown data output (**135**) is generated by the wireline tool (**106***c*) and collected at the surface. The wireline tool (**106***c*) may be positioned at various depths in the wellbore (**136**) to provide a survey of the subterranean formation.

FIG. **1**D depicts a production operation being performed by a production tool (**106***d*) deployed from the rig (**128**) and into the completed wellbore (**136**) of FIG. **1**C for drawing fluid from the downhole reservoirs into surface facilities (**142**). Fluid flows from reservoir (**104**) through wellbore (**136**) and to the surface facilities (**142**) via a surface network (**144**). Sensors (S) positioned about the oilfield (**100**) are operatively connected to a surface unit (**142**) for collecting data therefrom. During the production process, data output (**135**) may be collected from various sensors (S) and passed to the surface unit (**134**) and/or processing facilities. This data may be, for example, reservoir data, wellbore data, surface data, and/or process data.

While FIGS. **1**A-**1**D depict monitoring tools used to measure properties of an oilfield (**100**), it will be appreciated that the tools may be used in connection with non-oilfield operations, such as mines, aquifers or other subterranean facilities. Also, while certain data acquisition tools are depicted, it will be appreciated that various measurement tools capable of sensing properties, such as seismic two-way travel time, density, resistivity, production rate, etc., of the subterranean formation and/or its geological structures may be used. Various sensors (S) may be located at various positions along the subterranean formation and/or the monitoring tools to collect and/or monitor the desired data. Other sources of data may also be provided from offsite locations.

The oilfield configuration in FIGS. **1**A-**1**D is not intended to limit the scope of the invention. Part, or all, of the oilfield (**100**) may be on land and/or sea. Also, while a single oilfield at a single location is depicted, the present invention may be used with any combination of one or more oilfields (**100**), one or more processing facilities and one or more wellsites. Additionally, while only one wellsite is shown, it will be appreciated that the oilfield (**100**) may cover a portion of land that hosts one or more wellsites, including injection wellsite(s). One or more gathering facilities may be operatively connected to one or more of the wellsites for selectively collecting downhole fluids from the wellsite(s).

FIGS. **2**A-**2**D are graphical depictions of data collected by the tools of FIGS. **1**A-D, respectively. FIG. **2**A depicts a seismic trace (**202**) of the subterranean formation of FIG. **1**A taken by survey tool (**106***a*). The seismic trace measures a two-way response over a period of time. FIG. **2**B depicts a core sample (**133**) taken by the drilling tool (**106***b*). The core test typically provides a graph of the density, resistivity, or other physical property of the core sample (**133**) over the length of the core. Tests for density and viscosity are often performed on the fluids in the core at varying pressures and temperatures. FIG. **2**C depicts a well log (**204**) of the subterranean formation of FIG. **1**C taken by the wireline tool (**106***c*). The wireline log typically provides a resistivity measurement of the formation at various depths. FIG. **2**D depicts a production decline curve (**206**) of fluid flowing through the subterranean formation of FIG. **1**D taken by the production tool (**106***d*). The production decline curve (**206**) typically provides the production rate Q as a function of time t.

The respective graphs of FIGS. **2**A-**2**C contain static measurements that describe the physical characteristics of the formation. These measurements may be compared to determine the accuracy of the measurements and/or for checking for errors. In this manner, the plots of each of the respective measurements may be aligned and scaled for comparison and verification of the properties.

FIG. **2**D provides a dynamic measurement of the fluid properties through the wellbore. As the fluid flows through the wellbore, measurements are taken of fluid properties, such as flow rates, pressures, composition, etc. As described below, the static and dynamic measurements may be used to generate models of the subterranean formation to determine characteristics thereof.

FIG. **3** is a schematic view, partially in cross section of an oilfield (**300**) having data acquisition tools (**302***a*), (**302***b*), (**302***c*), and (**302***d*) positioned at various locations along the oilfield for collecting data of a subterranean formation (**304**). The data acquisition tools (**302***a*-**302***d*) may be the same as data acquisition tools (**106***a*-**106***d*) of FIG. **1**, respectively. As shown, the data acquisition tools (**302***a*-**302***d*) generate data plots or measurements (**308***a*-**308***d*), respectively.

Data plots (**308***a*-**308***c*) are examples of static data plots that may be generated by the data acquisition tools (**302***a*-**302***d*), respectively. Static data plot (**308***a*) is a seismic two-way response time and may be the same as the seismic trace (**202**) of FIG. **2**A. Static plot (**308***b*) is core sample data measured from a core sample of the formation (**304**), similar to the core sample (**133**) of FIG. **2**B. Static data plot (**308***c*) is a logging trace, similar to the well log (**204**) of FIG. **2**C. Data plot (**308***d*) is a dynamic data plot of the fluid flow rate over time, similar to the graph (**206**) of FIG. **2**D. Other data may also be collected, such as historical data, user inputs, economic information, other measurement data, and other parameters of interest.

The subterranean formation (**304**) has a plurality of geological structures (**306***a*-**306***d*). As shown, the formation has a sandstone layer (**306***a*), a limestone layer (**306***b*), a shale layer (**306***c*), and a sand layer (**306***d*). A fault line (**307**) extends through the formation. The static data acquisition tools are preferably adapted to measure the formation and detect the characteristics of the geological structures of the formation.

While a specific subterranean formation (**304**) with specific geological structures are depicted, it will be appreciated that the formation may contain a variety of geological structures. Fluid may also be present in various portions of the formation. Each of the measurement devices may be used to measure properties of the formation and/or its underlying structures. While each acquisition tool is shown as being in specific locations along the formation, it will be appreciated that one or more types of measurement may be taken at one or more location across one or more oilfields or other locations for comparison and/or analysis.

The data collected from various sources, such as the data acquisition tools of FIG. **3**, may then be evaluated. Typically, seismic data displayed in the static data plot (**308***a*) from the data acquisition tool (**302***a*) is used by a geophysicist to determine characteristics of the subterranean formation (**304**). Core data shown in static plot (**308***b*) and/or log data from the well log (**308***c*) is typically used by a geologist to determine various characteristics of the geological structures of the subterranean formation (**304**). Production data from the production graph (**308***d*) is typically used by the reservoir engineer to determine fluid flow reservoir characteristics.

FIG. **4** shows an oilfield (**400**) for performing simulation operations. As shown, the oilfield has a plurality of wellsites (**402**) operatively connected to a central processing facility (**454**). The oilfield configuration of FIG. **4** is not intended to limit the scope of the invention. Part or all of the oilfield may be on land and/or sea. Also, while a single oilfield with a single processing facility and a plurality of wellsites is depicted, any combination of one or more oilfields, one or more processing facilities and one or more wellsites may be present.

Each wellsite (**402**) has equipment that forms a wellbore (**436**) into the earth. The wellbores extend through subterranean formations (**406**) including reservoirs (**404**). These reservoirs (**404**) contain fluids, such as hydrocarbons. The wellsites draw fluid from the reservoirs and pass them to the processing facilities via surface networks (**444**). The surface networks (**444**) have tubing and control mechanisms for controlling the flow of fluids from the wellsite to the processing facility (**454**).

FIG. **5** shows a schematic view of a portion of the oilfield (**400**) of FIG. **4**, depicting a producing wellsite (**402**) and surface network (**444**) in detail. The wellsite (**402**) of FIG. **5** has a wellbore (**436**) extending into the earth therebelow. In addition, FIG. **5** shows an injection wellsite (**502**) having an injection wellbore (**506**). As shown, the wellbores (**436**) and (**506**) has already been drilled, completed, and prepared for production from reservoir (**404**).

Wellbore production equipment (**564**) extends from a wellhead (**566**) of wellsite (**402**) and to the reservoir (**404**) to draw fluid to the surface. The wellsite (**402**) is operatively connected to the surface network (**444**) via a transport line (**561**). Fluid flows from the reservoir (**404**), through the wellbore (**436**), and onto the surface network (**444**). The fluid then flows from the surface network (**444**) to the process facilities (**454**).

As described above, fluid may be injected through an injection wellbore, such as the wellbore (**506**) to gain additional amounts of hydrocarbon. Fluid may be injected to sweep hydrocarbons to producing wells and/or to maintain reservoir pressure by balancing extracted hydrocarbons with injected fluid. The wellbore (**506**) may be a new well drilled specifically to serve as an injection wellbore, or an already existing well that is no longer producing hydrocarbons economically. As shown in FIG. **5**, wellbore injection equipment (**514**) extends from a wellhead (**516**) of injection wellsite (**502**) to inject fluid (e.g., shown as (**511**) and (**512**) in FIG. **5**) in or around the periphery of the reservoir (**404**) to push hydrocarbons (e.g., shown as (**513**) in FIG. **5**) toward a producing wellbore, such as the wellbore (**436**). The injection wellsite (**502**) is operatively connected to an injection transport line (**515**), which provides the injection fluid to the injection wellsite (**502**) through the wellhead (**516**) and down through the well injection equipment (**514**).

The injected fluid may include water, steam, gas (e.g., carbon dioxide), polymer, surfactant, other suitable liquid, or any combinations thereof. A substance that is capable of mixing with hydrocarbons remaining in the well is called miscible. For example, a surfactant (e.g., shown as (**511**) in FIG. **5**), a chemical similar to washing detergents, can be injected into a reservoir mixing with some of the hydrocarbons locked in rock pores (e.g., shown as (**512**) in FIG. **5**), and releases the hydrocarbons so that fluid (e.g., shown as (**513**) in FIG. **5**) can be pushed towards the producing wells. One technique in fluid injection is MWAG injection, which involves the use of gases such as natural gas (i.e., naturally occurring mixture of hydrocarbon gases), carbon dioxide, or other suitable gases. The injected gas (e.g., natural gas, carbon dioxide, etc.) mixes with some of the remaining hydrocarbons in the reservoir, unlocks it from the pores, and pushes the fluid (e.g., shown as (**513**) in FIG. **5**) to producing wells. Water (e.g., shown as (**511**) in FIG. **5**) is often injected behind the gas (e.g., shown as (**512**) in FIG. **5**) to push the miscible gas and unlocked hydrocarbons along based on the incompressible nature of water.

The efficacy of the MWAG injection in recovering remaining hydrocarbons from an oilfield depends on careful planning of the injection schedules such as the selection of fluid, the determination of the composition of the fluid to ensure the miscibility, the pumping rate, the switching cycles between different injected fluid, the controlled interface, and capillary forces between different injected fluid, etc. The MWAG injection schedule should be determined considering geological and geo-physical information, such as temperature, pressure, porosity, permeability, composition, etc. In addition to the complexity in determining MWAG injection schedules, the source of the injection fluid, the constraints of the processing facilities and surface network, and market value of oil can all impact the overall performance of the oilfield operation.

An integrated simulation method described below, can be used, for example, to model the MWAG injection operation including various aspects of the oilfield, such as geological, geo-physical, operational, financial, etc. In the integrated simulation method, various constraints of the oilfield operation may be considered, such as the network constraints, the processing facility constraints, the fluid source constraints, the reservoir constraints, the market price constraints, the financial constraints, etc.

As further shown in FIG. **5**, sensors (S) are located about the oilfield (**400**) to monitor various parameters during oilfield operations. The sensors (S) may measure, for example, pressure, temperature, flow rate, composition, and other parameters of the reservoir, wellbore, surface network, process facilities and/or other portions of the oilfield operation. These sensors (S) are operatively connected to a surface unit (**534**) for collecting data therefrom. The surface unit may be, for example, similar to the surface unit (**134**) of FIGS. **1**A-D.

One or more surface units (**534**) may be located at the oilfield (**400**), or linked remotely thereto. The surface unit (**534**) may be a single unit, or a complex network of units used to perform the necessary modeling/planning/management functions (e.g., in MWAG injection scheduling) throughout the oilfield (**400**). The surface unit may be a manual or automatic system. The surface unit may be operated and/or adjusted by a user. The surface unit is adapted to receive and store data. The surface unit may also be equipped to communicate with various oilfield equipment. The surface unit may then send command signals to the oilfield in response to data received or modeling performed. For example, the MWAG injection schedule may be adjusted and/or optimized based on modeling results updated according to changing parameters throughout the oilfield, such as geological parameters,

geo-physical parameters, network parameters, process facility parameters, injection fluid parameters, market parameters, financial parameters, etc.

As shown in FIG. **5**, the surface unit (**534**) has computer facilities, such as memory (**520**), controller (**522**), processor (**524**), and display unit (**526**), for managing the data. The data is collected in memory (**520**), and processed by the processor (**524**) for analysis. Data may be collected from the oilfield sensors (S) and/or by other sources. For example, oilfield data may be supplemented by historical data collected from other operations, or user inputs.

The analyzed data (e.g., based on modeling performed) may then be used to make decisions. A transceiver (not shown) may be provided to allow communications between the surface unit (**534**) and the oilfield (**400**). The controller (**522**) may be used to actuate mechanisms at the oilfield (**400**) via the transceiver and based on these decisions. In this manner, the oilfield (**400**) may be selectively adjusted based on the data collected. These adjustments may be made automatically based on computer protocol and/or manually by an operator. In some cases, well plans are adjusted to select optimum operating conditions or to avoid problems.

To facilitate the processing and analysis of data, simulators may be used to process the data for modeling various aspects of the oilfield operation. Specific simulators are often used in connection with specific oilfield operations, such as reservoir or wellbore simulation. Data fed into the simulator(s) may be historical data, real time data or combinations thereof. Simulation through one or more of the simulators may be repeated or adjusted based on the data received.

As shown, the oilfield operation is provided with wellsite and non-wellsite simulators. The wellsite simulators may include a reservoir simulator (**340**), a wellbore simulator (**342**), and a surface network simulator (**344**). The reservoir simulator (**340**) solves for hydrocarbon flow through the reservoir rock and into the wellbores. The wellbore simulator (**342**) and surface network simulator (**344**) solves for hydrocarbon flow through the wellbore and the surface network (**444**) of pipelines. As shown, some of the simulators may be separate or combined, depending on the available systems.

The non-wellsite simulators may include process (**346**) and economics (**348**) simulators. The processing unit has a process simulator (**346**). The process simulator (**346**) models the processing plant (e.g., the process facilities (**454**)) where the hydrocarbon(s) is/are separated into its constituent components (e.g., methane, ethane, propane, etc.) and prepared for sales. The oilfield (**400**) is provided with an economics simulator (**348**). The economics simulator (**348**) models the costs of part or all of the oilfield (**400**) throughout a portion or the entire duration of the oilfield operation. Various combinations of these and other oilfield simulators may be provided.

FIG. **6** depicts a schematic view of an oilfield simulator (**300**) for modeling operations of an oilfield (**300**). This simulator (**300**) may form part of an overall production system of the oilfield. As shown, several simulators of the oilfield are operatively linked as an integrated asset model for modeling integrated operation therebetween. Depending on the desired outcome, certain simulators may be selectively linked in a desired configuration. While a variety of combinations may be envisioned, FIG. **6** depicts the combination of three reservoir simulators (**340***a*, **340***b*, **340***c*), two wellbore simulators (**342***a*, **342***b*), a surface network simulator (**344**), a process simulator (**346**) and an economics simulator (**348**). A variety of combinations of two or more simulators may be selectively linked to perform integrated simulations.

In the example shown, a set of simulators is selected to depict the various sources that affect the flow of fluid through the oilfield. At the far left are three different reservoir simulators (**340***a*, **340***b*, **340***c*), which are provided to depict various levels of approximation in mathematical representation of the reservoir. These reservoir simulators (**340***a*, **340***b*, **340***c*) calculate the flow of hydrocarbon(s) from the reservoir and into the wells and the flow of fluid into the reservoir from injection wells. One or more of the same and/or different reservoir simulators may be used. For example, reservoir simulator (**340***a*) is a full reservoir simulation model with increased accuracy, but reduced speed. Reservoir simulator (**340***b*) is a tank model proxy of a reservoir simulator, which typically provides a simplified representation of a reservoir simulation model. This type of reservoir simulator is typically less accurate, but faster to solve. Reservoir simulator (**340***c*) is a lookup table proxy of a reservoir simulator, which is typically even more simplified and faster to solve.

FIG. **6** demonstrates that, depending on the desired analysis, various combinations of one or more simulators may be used to perform the overall simulation. Each may have benefits, and the various outcomes may be compared. In the depicted example, some of the simulations can take more than a week to run once. Thus, one or more of the desired reservoir simulators may be selectively included to provide more immediate outputs that may be compared with the more precise simulations that are generated later.

As further shown in FIG. **6**, the wellbore simulators (**342***a*, **342***b*) and surface network simulator (**344**) are integrated into the oilfield simulation adjacent the reservoir simulators (**340***a*, **340***b*, **340***c*). Surface network simulator (**344**) is operatively linked to the wellbore simulators (**342***a*, **342***b*). These wellbore simulators (**342***a*, **342***b*) and surface network simulator (**344**) calculate the flow of hydrocarbons in the well and through the surface pipeline surface network (not shown). The simulators are also used to model injection of fluids into the reservoir. As shown, there are different wellbore simulators (**342***a*, **342***b*) that may be used for the oilfield simulation. The wellbore simulators (**342***a*, **342***b*) are selectively linked to the reservoir simulators (**340***a*, **340***b*, **340***c*) to provide data flow therebetween, as will be described further below.

Like the reservoir simulator (**340***a*, **340***b*, **340***c*), wellbore simulator (**342***a*, **342***b*), and surface network simulator (**344**), process (**346**) and/or economics simulator(s) (**348**) may also be used in the overall oilfield simulation. The process simulator (**346**) models the activities of, for example, a crude oil & gas processing plant for separation of petroleum into constituent components and creation of sellable products. The process simulator (**346**) is operatively connected to the surface network simulator (**344**). Finally, the economics simulator (**348**) is operatively connected to the process simulator (**346**). A spreadsheet model may optionally prepare the production data from the process simulator (**346**) for economic analysis. The economics simulator (**348**) models the economic evaluation at every time step of an integrated asset model. Although FIG. **6** shows one example of how the economic simulator is connected for performing the integrated simulation, in other examples the economics model can actually be connected to any point in the integrated asset model where oil and gas production forecasts can be generated; from a well in the reservoir simulator, from a well in the network model, from the export node of the network representing the total production of the field, or from separated hydrocarbon component streams in the process plant.

The simulators of FIG. **6** depict the simulators operatively linked for data flow therebetween. The simulators are selectively linked to permit data to flow between the desired simulators. Once linked, the simulators may be configured to share data and/or outputs between the connected simulators. The

data and/or outputs received from one simulator may affect the results of other simulators.

The production system may be used to link different parts of oilfield operations, such as the reservoir, wellbore, surface, processing, and economics simulators depicted. The simulators may be cross-platform and/or real-time. One or more simulators may be of similar configurations, or provided by different sources which may cause problems in cross-communication. The simulators, therefore, are linked in a manner that permits operation therebetween. The simulators may be linked, for example, using reservoir to surface coupling and/or stream/variable based couplings. Preferably, these couplings link models together so that the models may solve together over the full simulation timeframe. In some cases, the simulators will initially model separately, in preparation for a full simulation.

The coupling between simulators preferably permits selective passing of data therebetween. In some cases, data flows freely between simulators. In other cases, data flow is restricted or selectively permitted. For example, it may be more time efficient to permit a simulator to complete its simulation process prior to linking to other simulators and receiving additional data therefrom. It may also be desirable to exclude certain simulators if, for example, a defect exists in the simulation.

User inputs may be used to provide constraints, alerts, filters, or other operating parameters for the simulators. Thus, where one simulator indicates that operating conditions are unacceptable, such restrictions may be passed to other simulators to limit the available parameters for the remainder of the oilfield operation.

Simulators are typically linked using couplings, such as generic node/variable couplings or special network couplings. As shown in FIG. **6**, generic node/variable couplings (**352***a*, **352***b*) form connections between wellbore simulators (**342***a*, **342***b*) and surface network simulator (**344**), respectively. A generic node/variable coupling (**354**) forms a connection between surface network simulator (**344**) and process simulator (**346**). Another generic node/variable coupling (**356**) forms a connection between process simulator (**346**) and economics simulator (**348**). These types of couplings permit data to flow freely between the simulators. Thus, data from the wellbore, surface, processing, and economics simulators is free to flow therebetween.

In other cases, special network couplings are used to facilitate and/or manipulate the flow of data between the simulators. As shown in FIG. **6**, reservoir simulators (**340***a*, **340***b*) are connected to wellbore simulator (**342***a*) via special network couplings (**350***a* and **350***b*), respectively. Reservoir simulator (**340***c*) is connected to wellbore simulator (**342***b*) via special network coupling (**350***c*).

The special network coupling (**350***c*), such as implicit or explicit couplings, may be used between the reservoir and wellbore simulators to impose accurate hydraulic response from the network on the reservoir. These couplings permit the coupled simulators to model network equipment, such as gas lift valves, pumps, compressor, and chokes. The couplings may also be configured to permit the coupled simulators to take account of flow assurance issues such as wax and hydrate formation.

An implicit coupling permits simultaneous solution of the coupled simulators. For example, a coupling can be used to provide reservoir and the wellbore governing equations. In some cases, this may be a faster method for performing the simulations, and provide for sharing of data between the simulators. In the example shown in FIG. **6**, an implicit coupling between reservoir simulator (**340***c*) and wellbore simulator (**342***b*) provides for simultaneous simulation based on all available data of both simulators.

An explicit coupling may be used to solve reservoir and wellbore governing equations sequentially in an iterative process. With the sequential process, one simulator performs its simulation before the other simulator begins its simulation. In this manner, the first simulator can impose boundary conditions onto the next simulator. In the example shown in FIG. **6**, an explicit coupling (**350***c*) between reservoir simulator (**340***c*) and wellbore simulator (**342***b*) indicates that the reservoir simulator completes its simulation prior to linking to wellbore simulator (**342***b*). Thus, wellbore simulator (**342***b*) is impacted by the output of wellbore simulator (**340***c*). In other words, reservoir simulator (**340***c*) imposes boundary conditions on the wellbore simulator. The wellbore is then solved and the reservoir and wellbore pressures and flow rates are compared. If the flows and pressure are within a given tolerance, the reservoir and wellbore simulators are considered balanced.

The selected couplings may also be tight or loose. A tight coupling provides coupling at a Newton level. Consider a reservoir simulation at time t_0. In order to progress to time t_1 the reservoir material balance equations are solved at each non-linear (Newton) iteration. In order to introduce the effects of the network on the reservoir model (hydraulic response, injection, withdrawal), the network is balanced with the reservoir at a prescribed number of Newtons. For example, where a reservoir simulator is coupled to a wellbore simulator using tight coupling, the system may be balanced using a chosen network balancing method. Reservoir material balance equations are then solved at the first Newton iteration. The wellbore and reservoir simulators are then rebalanced. This process may be repeated as desired.

Tight coupling may be used to balance the reservoir and the wellbore at the end of the timestep. The network may then be modelled in reservoir during the coupling process. This may be used to reduce the effect if well interaction in the reservoir is significant. Depending on the number of Newtons and iterations, tight coupling may require a high number of network balancing iterations.

Loose couplings involve a single reservoir network balance at the start of the timestep. Once a balanced solution has been achieved, the reservoir may complete its timestep without further interaction with the network. This is similar to tight coupling, but with the reservoir simulator initialized to zero. This type of coupling may be used for coupling multiple reservoirs, since two reservoirs may take a different number of Newton iterations to perform the same timestep.

The coupling may be positioned in different locations about the wellbore. For example, the reservoir-wellbore simulator coupling may be a bottom-hole, top-hole, or group coupling. With a bottom-hole coupling, the well completion is modelled in the reservoir model from sandface to bottom hole. The well tubing is modelled in the network. This means that an inflow model in the network well is typically ignored. The bottom hole may be used to provide more well accurate modelling (multiphase flow correlations/pressure traverse), and flow assurance (compositional model/temperature variations). However, the bottom-hole coupling may provide unstable region on well curve that causes convergence issues, involve solving an extra branch per well, require tubing defined in both reservoir and network, and ignore certain completion models.

With top-hole coupling, the well completion and tubing is modelled in the reservoir. The well boundary nodes in the network take account of this. In the case of the wellbore simulator, sources or sinks are used to represent wells. Top-

hole coupling typically provides less branches in network model, inexpensive well bore lookup in reservoir, and smoothing in the reservoir VLP curve. However, it may lose resolution in the well bore calculation, and may not be compatible with certain network balancing schemes.

With group coupling, a reservoir well-group representing a production manifold may be coupled to a source in a network. The integrated simulator may set a common top-hole pressure constraint on the wells, and impose a hydraulic response from the network. A large network may be significantly reduced in size, but resolution may be lost in the network simulation.

In some cases, there are constraints on the type of coupling, such as bottom-hole pressure, top-hole pressure, oil rate, water rate, gas rate, liquid rate, reservoir volume rate. During the network balancing process, the reservoir and the network exchange boundary conditions in order to arrive at a converged solution. Once convergence has been achieved, the reservoir may be instructed to continue to the next timestep. At this point, the oilfield simulator may impose constraints on the reservoir wells that reflect the conditions of the converged system.

Other constraints may involve limitations to the simulation. For example, top-hole pressure may not be a valid constraint in the case of bottom hole coupling; holding pressure constant over a long step results may result in a decline in rate and a pessimistic production forecast; holding rate constant over a long timestep may result in a pressure decline. These additional constraints may be included to prevent overly optimistic production forecast, or wells shutting in. While constraints may occur at any coupling, these constraints typically occur along the reservoir/wellbore coupling.

It is desirable to have the oilfield simulator coupled in a manner that will achieve network balancing within a given set of constraints. In some cases, production may begin to decline after a period of steady production. The wells rate control could be imposed in the reservoir as a well or group limit. It could also be imposed in the network as a rate limit on a network branch. After the initial period, the well may start to decline. This could be a result of insufficient oil production potential for the well to produce its requirements. In this case, the reservoir may switch the wells control mode from oil to its next most stringent control mode. This may be another rate control (water/gas) or a pressure limit imposed on the well as a result of network balancing.

One reason for this may be that the system is constrained by reservoir deliverability. In order to produce the daily requirements through the network, the minimum reservoir pressure (P_W) may be required to be greater than or equal to the network pressure (P_N). As fluid is withdrawn from the reservoir, the reservoir pressure typically declines. When $P_W<P_N$, the network may be cut back in order to increase flow. In such a case, the system is constrained by network deliverability.

Network balancing may be performed to select the optimum operating conditions. Each time a simulator asks the network to solve, it must decide what boundary conditions to pass to the network. The type of network model and the network balancing strategy chosen by the user determine the basis for this decision.

The network type may be automatically determined by the oilfield simulator. The network is determined by considering boundary conditions and additional fluid characterization data that are passed from oilfield simulator to the network. Depending on the type of network, a boundary condition may be specified. For example, black oil production may have a boundary condition for Stock tank rates or Linear IPR (single phase), GOR, and watercut. Compositional production may have a boundary condition for mass rate and mole fractions, or mass IPR, and mole fractions. Water injection may have a boundary condition of stock tank water rate or water injectivity pressure flow relationship. Black oil injection may have a boundary condition of stock tank gas rate or gas injectivity pressure flow relationship. Compositional injection may have a boundary condition of mass rate or mass injectivity pressure flow relationship. Other networks and corresponding boundary conditions may be defined.

The network may have further defined types of couplings, such as rate base, fast PI, chord slope, and obey reserve limits. Rate based coupling is the simplest form of coupling a reservoir to a network. This type of coupling specifies rates in the network and imposes pressure limits on the reservoir. With this type of coupling, the oilfield simulator transfers rate-based boundary conditions to the network.

Based on the integrated simulation method described above, an optimization workflow uses the integrated models that combines the reservoir model with the surface facility network model and the process plant model to define the optimum MWAG cycle.

FIG. **7**A is a graph (**400***a*) illustrating the case where a reservoir well is coupled to a network well without rate constraint. In this case, the reservoir well should produce up to the pressure limit supplied by the hydraulic response of the network model. This requires the network balancing process to iterate to find the intersection of the reservoir inflow curve and the network well performance curve. To achieve this balancing, the following steps may be performed

- The reservoir well model is queried for its pressure and flow (P**1** and Q**1**) this give us point **1** on the reservoir inflow curve.
- The rate, Q**1**, is set as the boundary condition to the network, which solves to find point **2**—the first point on the well curve.
- Pressure P**2** is set as a limit in the reservoir well model, which is solved to give point **3**.
- The resulting rate, Q**4**, is set in the network to find point **4**.

This process may be repeated until the reservoir and network pressure and flow values are within a given tolerance.

In FIG. **7**A, the rate based balancing process has taken multiple iterations to find a solution. This is because the system is constrained by network backpressure. As a result, the algorithm must home in on the curve intersection (i.e. converge both pressure and flow rate).

FIG. **7**B illustrates a system where the reservoir well coupled to a network well is rate constrained in the reservoir. The reservoir inflow curve is limited to a specific value—Q_{limit}. The system operates at this limit as long as the pressure constraint imposed on the well does not exceed a maximum threshold denoted by P_{max}.

The rate based coupling algorithm deals with this situation as follows:

- The well model is queried for its operations conditions and will return Qlimit and Pmas.
- Qlimit is set as a constraint in the network. The network solves are returns a pressure (Pn) and flow (Qn=Qlimit).
- As Pn<Pmax, the system is considered to be converged.

The converged system is achieved here in a single iteration. This is because an assumption is made that the positive pressure difference between the reservoir pressure (P_{max}) and the network pressure (P_n) can be taken up by a network choke.

FIG. **8** shows how the fast PI method finds a solution. The fast PI method is a non-iterative network balancing process. This coupling has linear IPR's that are specified in the network, and the rate limits are imposed on the reservoir. The network balancing is a three-step process. These steps are:

Query the reservoir for the well linear IPR curve at the current operating point.

Pass the IPR as a boundary condition to the network simulator and solve for network pressure and flow.

Set the flow rate calculated by the network simulator in the reservoir.

The method relies on the network to perform the rate allocation. So any rate limits should be imposed at the network level. Because the balancing algorithm sets rates in the reservoir, existing reservoir rate targets and limits are obeyed. In order to impose flow rate constraints on the system, rate constraints are imposed on the network model.

At the start of the timestep, the linear IPR for the well is queried. This will be the tangent to the well curve at its current operating pressure and flow rate. This IPR is passed to the network, which solves for point **2**. The corresponding flow rate is set in the reservoir. This balancing scheme is non-iterative. The rate from the network is taken as the updated operating point. There is no test for convergence. In some cases, material may be balanced, while pressure may not. It may possible to improve the accuracy of this method by performing fast PI balances at multiple Newton iterations, usually if a single reservoir is coupled. The fast PI coupling is non-iterative, and robust. However, it may prohibit reservoir based well management, and may be inaccurate since only rate is balanced.

FIGS. **9**A, **9**B, and **9**C contain graphs illustrating the chord slope scheme. The chord slope scheme sets a chord slope of rates and PI taken from the reservoir model in the network. This coupling specifies either rates or IPR's in the network and imposes pressure limits on the reservoir. It aims to work with any pre-existing well and group controls in the reservoir models, as wells as imposing network back pressure.

The algorithm adapts itself to the reservoir by considering the last two operating points on the reservoir IPR. This means that non-linear behavior in the IPR (e.g. effects of skin factors or well/group constraints) can be passed to the network. To obtain information on how the IPR changes, at least two network balancing iterations are typically performed.

FIGS. **9**A and **9**B consider a coupled reservoir to network simulation with two distinct sets of well management controls. FIG. **9**A depicts a Network Constrained System. A reservoir simulation containing 20 wells fed into a common manifold (group). The reservoir wells are coupled to a network model. The wells in the reservoir are controlled on bottom hole pressure (no well or group rate control). The network contains the sink pressure specification and a given sink rate limit. In this case, the wells are controlled by the network back-pressure imposed on the reservoir.

Query the initial operating conditions of the reservoir wells to obtain point **1** on the IPR.

Pass the boundary conditions to the network. This may be:
Rate (shown in figure)
Linear PI Queried from well model

The network is solved to obtain point **2** on the well curve.

The network pressure is set in the reservoir.

The well model is solved and queried to return point **3**.

A Linear PI is constructed using the last two operating points on the IPR.

The PI is passed to the network, which solves to give point **4**.

Steps 4 through 7 are repeated until convergence is achieved.

At subsequent timesteps, the boundary condition passed to the network on the first timestep is the PI calculated at the convergence solution at the previous timestep.

FIG. **9**B depicts a graph of a Reservoir Constrained System. The wells are controlled using the reservoir group control target limit. Underlying wells operate up to an allocated quantity based on their production potential and the group target. The network models are restricted based on the sink pressure. In this case, the wells are controlled by the reservoir well controls—assuming the reservoir has sufficient pressure to support the flow through the network.

Query the initial operating conditions of the reservoir wells to obtain point **1** on the IPR.

Pass the boundary conditions to the network. This may be:
Rate
Linear PI Queried from well model (shown in figure)

The network is solved to obtain point **2** on the well curve.

The network pressure is set in the reservoir.

The well model is solved and queried to return point **3**. Note that this is on the constant rate section of the IPR.

A Linear PI is constructed using the last two operating points on the IPR.

The PI is passed to the network, which solves to give point **4**.

The resulting network pressure is passed to the reservoir to point **5**.

The algorithm detects that points **3** and **5** have the same flowrate—indicating the well is operating under a rate control imposed by the reservoir.

The network is specified with a constant rate boundary condition and solved.

Assuming the reservoir pressure is greater than the network pressure, the well is considered to be converged.

As the reservoir simulation marches through time, withdrawal will result in pressure decline.

FIG. **9**C depicts a graph of a wellbore operation with a Reduced Reservoir Pressure. This graph shows a well curve intersecting with an IPR curve, which is significantly flatter than in previous figures. This is meant to illustrate reduced reservoir pressure.

Query the initial operating conditions of the reservoir wells to obtain point **1** on the IPR.

Set rate based boundary conditions and solve the network. This results in point **2**.

The resulting network pressure is set in the reservoir and the well model is solved to give point **3**.

The reservoir cannot flow at the given pressure and is shut in the reservoir.

At this point, the Well Revival logic build into the coupling algorithm comes into effect.

Any wells that have been "temporarily" shut as a result of a network imposed pressure constraint are revived in the reservoir.

The revival limit may be set by the user to avoid excessive iterations.

If the revival limit is exceeded, the well is permanently shut in the reservoir.

A linear PI is constructed using points **1** and **3**. This is passed to the network as a boundary condition.

The network solves and returns point **4**.

The resulting network pressure is set in the reservoir and the well model is solved to give point **5**.

If the flowrates are different, the algorithm will use the last two operating points to construct a PI, or, if they are the same, a constant rate. In the limiting case of no flow, the PI is constructed using the current operating point and the last flowing operating point. In this case, the linear PI is constructed using points **5** and point **1**.

The PI is passed to the network and solved for point **6** where the system reaches convergence.

If may be necessary to perform well revivals until a convergence solution is achieved. This can result in increased run times and, in some case, unnecessary wells shutting. This typically provides accurate, iterate coupling to ensures pressure and rate convergence, and obeys various simulator constraints simultaneously. However, this process is iterative and may be slower. Also, wells may shut in due to insufficient reservoir pressure.

Another coupling configuration that may be used is the obey reservoir limits. This coupling specifies rates in the network, and imposes rate limits in the reservoir. The well management available in the reservoir simulator is extensive. The aim of this method is to allow a reservoir to be coupled to a network with minimal intervention as a result of network constraints. This may be done to ensure that the reservoir well management controls are obeyed whilst avoiding the well shut-in problems, such as those that may occur with the Chord Slope method.

The coupled network may only be pressure specified at the export note. This method does not contain rate constraints. The obey eclipse coupling algorithm work as shown below:

The well model is queried for its operating point.

Constant rate boundary condition are sent to the network and it is solved.

If any network well pressures are greater than the respective reservoir well pressure, the well must be cut back.

A relaxation parameter is calculated for the well based on the difference pressure difference.

The reservoir well is cut back using the relaxing parameter ($0<r<1$)

The well model is solved with the new rate.

Steps 1-4, detailed immediately above, are repeated until no well violate the pressure limit imposed by the network.

The reservoir continues to the next timestep.

The primary difference between other coupling method and this method is what is set in the reservoir.

FIG. **10** depicts a method of producing fluids from an oilfield, such as the oilfield of FIG. **1**. This method involves the selective linking of simulators throughout the oilfield to predict and/or control oilfield operations.

Data is gathered from the oilfield operation (Step **1001**). In some cases, this data is historical data based on similar oilfield operations, similar geological formations, or applicable scenarios. User inputs may be provided based on known parameters, such as sampling of formation fluid. Data may also be collected from sensors positioned about the oilfield as shown in FIG. **5**. Data may be stored in memory and accessed as needed to perform the simulations herein.

The method involves selecting simulators for the oilfield (Step **1002**). A variety of simulators may be selected to define the oilfield simulation, such as the reservoir simulators (**340***a*, **340***b*, **340***c*), wellbore simulators (**342***a*, **342***b*), surface network simulator (**344**), process simulator (**346**) and economics simulator (**348**) of FIG. **6**. For example, the reservoir simulator (**340***a*) may include functionality to model fluid injection and/or perform thru-time analysis is selected for modeling MWAG injection operation.

The selected simulators are positioned along a flow path (Step **1004**). This brings the oilfield simulation into a process flow diagram format as shown in FIG. **6**. The connections are preferably established to provide a sequence for the flow of production through the flow diagram. As shown in FIG. **6**, the production fluid flows from reservoir simulator, to wellbore simulator, to surface network simulator to process simulator, and to the economics simulator.

Couplings are established between the selected simulators (Step **1006**). These couplings are specified according to the type of coupling desired for the specific flow diagram. As shown in FIG. **6**, couplings (**352***a*), (**352***b*), (**354**), and (**356**) are general node couplings. Couplings (**350**, **350***b*, **350***c*) are special couplings. For example, the coupling may involve coupling a reservoir simulator with functionality to model fluid injection and/or perform thru-time analysis is selected for modeling MWAG injection operation.

The coupled simulators are then formatted (Step **1008**). For example, the coupled reservoir and wellbore simulators are defined as bottom-hole, top-hole, or grouped couplings. Because the surface network, process and economics simulators are general couplings, no such definition is required.

The processing setup for the oilfield simulator is then set (Step **1009**). Setup parameters may include, for example, time frame, frequency, display, etc., and be used to determine, for example, start time, end time, and reporting frequency during simulation runs.

The oilfield simulator is then performed (Step **1010**). As shown in the configuration of FIG. **6**, the reservoir simulation will solve first. The simulation model and the well/network model iterate until they come to a common solution for the deliverability of each well within a pre-defined tolerance. The results from the network are then sent to the process simulator, which then solves the plant operations defined therein. The economics simulator is then linked to any model that generates a production forecast.

Results and/or reports are generated as desired (Step **1012**). As the oilfield simulator runs, status messages and/or results of underlying simulators may be displayed. Interim and/or final results may be selectively generated.

The results may be used to adjust changes in the oilfield simulator, for example, in modeling MWAG injection operation (Step **1014**). If the simulator is not providing results as desired, or if other data suggests a problem, the simulator may be adjusted. For example, the coupling or constraints defined for the simulation may be altered.

The oilfield operation, for example, the MWAG injection operation, may also be adjusted (Step **1016**). The simulators may provide information indicating problems at the wellsites that require action. The simulators may also indicate that adjustments in the oilfield operation may be made to improve efficiency, or correct problems. Well management strategy may be adjusted to define different development scenarios to be included in the integrated simulation run.

FIG. **11** is a flowchart depicting a method for optimizing the oilfield operation considering the reservoir uncertainty and/or financial uncertainty.

As shown in FIG. **10** above, optimal operations of an oilfield may be modeled using selectively coupled simulation under the assumption that every parameters are deterministically known, for example based on oilfield parameters measured using sensors positioned about the oilfield as shown in FIG. **3**. In some examples, the fraction of oil extracted or a net present value (NPV) of the oil produced may be maximized, or the water production may be minimized by optimally controlling various operational variables (e.g., oilfield control parameters) while accounting for physical constraints (or reservoir constraints, e.g., single well production or pump/valve limitation) and economic constraints (or financial constraints, e.g., drilling, logging, or stimulation costs). However, the presence of physical and/or economic uncertainties elevates the problem of optimization to a level of a risk-management problem. The method depicted in FIG. **11** encompasses elements to perform reservoir optimization under uncertainty and provides the risk analysis for decision

making. In addition, optimization is performed with the reservoir simulation selectively coupled to the rest of the production and/or injection systems so that the optimization takes into account all of the interdependencies of the different segments/models of the production and injection system of the oilfield. For example, the interdependency between different models of the production system may be that the amount of miscible gas available for MWAG injection into the reservoir model is determined by the output of the gas separation process in the process facility model. Furthermore, the physical constraints defined in each of the different segments/models of the full production and injection system may be honored by the optimizer within the selectively coupled simulators. For example, the physical constraint may be imposed by the process facility having a maximum capacity for handling gas produced from the field, or even be imposed by the condition that there is no capability for processing and transporting gas so that all gas produced must be flared, consumed as fuel, or re-injected into the reservoir.

As shown in FIG. **11**, initially a risk aversion factor is selected (Step **1102**). The risk aversion factor may reflect a preference of an oilfield decision maker toward risk level involved with the reservoir and/or financial uncertainties. Next, an oilfield control parameter is set to a predetermined value (Step **1104**). For example, the oilfield control parameter may be an input to an oilfield simulator such as a wellsite simulator and/or a non-wellsite simulator described in FIG. **5** above. In some examples, the oilfield control parameter, such as liquid-flow rates at various completions, flow-head pressure, and other action parameters may be monitored by a sensor positioned in the oilfield. Using the method depicted in FIG. **6**, the oilfield simulators may be selectively coupled using coupling mechanisms described in FIGS. **7-9** (Step **1106**). The couplings may also be constrained as described in FIG. **6** above based on the reservoir constraints and/or the financial constraints. Some inputs to the oilfield simulators may be uncontrollable and may not be monitored by the oilfield sensors, therefore are unknown and present uncertainties to the decision making concerning oilfield operations. Such an uncertainty parameter may be identified (Step **1108**). The uncertainty parameter may be the reservoir uncertainty (e.g., the pore volume, the fault transmissibilities, the regional or field-wide permeability or porosity, or the production index of the aquifer supporting the water displacement for oil production, etc.) or the financial uncertainty (e.g., oil price or discount rate, etc.)

The uncertainty parameter may be modeled in many different ways to generate an estimated performance of the oilfield operation (Step **1110**). For example, the uncertainty parameter may be modeled based on historical data, expert knowledge, experiments, analysis, or other appropriate methods. In some examples, the uncertainty parameter may be modeled by high/low values or high/low/median values of equal probabilities. Alternatively, a probability distribution may be obtained for the uncertainty parameter, in which case the uncertainty parameter may have a range of probable values each associated with a probability. The probability distribution may be a normal distribution, a log normal distribution, or other possible distributions. In other examples, the oil market price and oil production cost as uncertainty parameters may be modeled in many different ways such as constant oil price and cost with a selected discount rate, exponentially varying oil price and cost with different drifts for oil, gas, and cost, risk-neutral process for oil price with constant drift, volatility, and discounting at a risk-free rate, or risk-neutral process for oil price that is mean-reverting with a time-dependent drift. Parameters of these risk-neutral processes may be obtained from oil future and option contract prices in the market place such as the New York Mercantile Exchange.

As an example, m uncertainty parameters may be identified. Each uncertainty parameter may have n probable values in the probability distribution. The combination yields as many as $N=n^m$ model realizations. Each of these N model realizations may be performed using the selectively coupled simulators described in FIG. **6** above. As these N model realizations represent independent models, the modeling may be performed concurrently by distributing the simulation/calculations to various computer processors such as a shared-memory multiple-processor computer, a cluster of processors, or a network of independent computers. A performance measure may be generated by the selectively coupled simulators for each of these N model realizations. An estimated performance may then be generated based on a statistical function of these N performance measures.

In one example, the performance measure may be a net present value (NPV) of the reservoir, for example a post-tax NPV or a post-royalty NPV. The estimated performance may be formulated as a parameterized function F_λ based on the risk aversion factor, which is represented here by the parameter λ. An example of the parameterized function may be formulated as $F_\lambda=\mu-\lambda*\sigma$, where μ and σ represent a weighted average and a standard deviation, respectively, of the performance measure NPV generated by the selectively coupled oilfield simulators over N model realizations based on the probability distribution. This parameterized function may imply a maximization of the mean NPV simultaneously with a variable-importance minimization of the associated standard deviation, depending on the risk aversion factor λ. A set of λ may determine, in the (μ, σ) space, an envelope (referred to as efficient frontier) that maximizes μ for a given σ or minimizes σ for a given μ.

As the oilfield control parameter is set to various predetermined values in Step **1104**, the estimated performance is a function of the oilfield control parameter. Given a selected risk aversion factor, the Steps **1104-1110** may be iterated to identify an optimal value of the oilfield control parameter that optimizes the estimated performance (Step **1112**). As the estimated performance is formulated as a parameterized function based on the risk aversion factor λ, the optimal value of the oilfield control parameter is also a function of the risk aversion factor λ.

The Steps **1102-1112** may be repeated to generate optimal values of the oilfield control parameter and the corresponding estimated performances for a set of selected risk aversion factors. A desired risk aversion factor is then determined, for example based on a preference of decision maker for the oilfield operation (Step **1114**). From the risk management point of view, the various selected risk aversion factors may approximate a percentage confidence level, for example, in the case where the NPV values form a normal distribution. In one example, considering the risk aversion factor $\lambda=0$, there would be a 50% probability that a realized NPV will be greater than $F_0=\mu$, which is the weighted average. Therefore, the best median (or 50% confidence level) may be obtained by maximizing F_0. In another example, considering the risk aversion factor $\lambda=1$, there would be an 84% probability that a realized NPV will be greater than $F_1=\mu-\sigma$. Therefore, the optimum 84% confidence level may be obtained by maximizing F_1. In the case where NPV values are not normally distributed, the 84% confidence level is maximized somewhere along the efficient frontier, though not necessarily at the risk aversion factor $\lambda=1$. With a sufficiently large number N of model realizations, the 84% level may be determined for each

value of the risk aversion factor λ and the desired risk aversion factor may be determined accordingly.

FIG. **12** is a flowchart depicting a method for managing the oilfield operation based on the optimization loop of FIG. **11**.

As shown in FIG. **11** above, optimal operations (e.g., an injection operation) of an oilfield (e.g., an injection operation) may be modeled with consideration of reservoir and/or financial uncertainties. The optimal oilfield control parameters (e.g., water injection rate per zone, gas injection rate per zone, time of water injection per zone, time of gas injection per zone, etc.) may be determined by performing the optimization loop depicted in FIG. **11** based on a set of probability distribution of uncertainty parameter values (Step **1201**). The modeling may be subject to constraints of the oilfield, such as well constraints (e.g., flow velocity at a downstream choke may be constraint for erosion management), reservoir constraints, financial constraints, etc. Some of these constraints may be applied to the coupling in the modeling depicted in FIG. **6** above. With the optimal oilfield control parameters determined by the optimization loop of FIG. **11**, the oilfield operations are then performed (Step **1202**). As the modeling of the oilfield operations in the optimization loop depends on the probable values of the uncertainty parameters, the actual oilfield operation may deviate from the modeling prediction. Certain monitoring criteria (e.g., based on the severity of the deviation) may be set up for monitoring the real-life operations performance (e.g., reservoir pressure, well rate, or other production data) of the oilfield against the modeling prediction (Step **1203**). If the deviation is within the monitoring criteria, the oilfield operation continues to be performed in the monitoring loop (Steps **1202** and **1203**). The monitoring loop may be performed at a high frequency, for example, on daily or hourly basis to handle automated oilfield workflows thus alleviating production engineers and reservoir engineers from routine calculations to focus on analysis (e.g., performed in Step **1205**) for managing the oilfield.

If the deviation exceeds the monitoring criteria in Step **1203**, then a decision is made as to whether prior attempts to control the deviation failed thus an alarm is to be generated (Step **1204**). If the decision in Step **1204** is "NO", then an adjustment (e.g., choke positions of each wells) of the oilfield control parameter is determined using the coupled simulation method (e.g., as described in FIG. **6** above) to model the deviation and corresponding corrective actions (Step **1206**). The adjustment is then fed into the oilfield operation as a control loop (Step **1202**, **1203**, and **1206**). The control loop may be performed at a higher frequency, for example every 15 minutes as long as the deviation exceeds the monitoring criteria.

If the decision in Step **1204** is "YES", then an alarm is generated, which triggers an analysis to be performed (Step **1205**). The alarm may be received by a user in many different ways, for example, via email, through a task manager, or through a visualization window. The analysis may require human intervention (e.g., of the production engineers or reservoir engineers) and may involve predefined workflows, instructions given as best practices, or other guidelines based on the triggering event. For example, the user may determine that the alarm is a false alarm (Step **1207**) leading to an adjustment of the monitoring criteria (Step **1208**), in which case the oilfield operations may return to the monitoring loop (Steps **1202** and **1203**). In another example, the user may determine that the alarm is not a false alarm and the optimization loop may need to be adjusted (Step **1209**), in which case the constraints, the control parameters, and/or the uncertainty parameters may be adjusted and the optimization loop (Step **1201**) re-performed accordingly. The analysis loop (Steps **1201**, **1202**, **1203**, **1204**, **1205**, **1207**, and **1209**) is triggering event driven and may be performed at a medium frequency ranging, for example from daily to monthly.

In some examples, the user may determine a new optimization loop may be required, for example, different control parameters may be identified, different probability distribution or different risk aversion factors may be used, etc. The optimization loop may then be re-configured accordingly. This may be done for the long term planning of the oilfield at a low frequency ranging, for example from months to years.

The steps of portions or all of the process may be repeated as desired. Repeated steps may be selectively performed until satisfactory results achieved. For example, steps may be repeated after adjustments are made. This may be done to update the simulator and/or to determine the impact of changes made.

The data input, coupling, layout, and constraints defined in the simulation provide flexibility to the simulation process. These factors of the various simulators are selected to meet the requirements of the oilfield operation. Any combination of simulators may be selectively linked to create the overall oilfield simulation. The process of linking the simulators may be re-arranged and simulations repeated using different configurations. Depending on the type of coupling and/or the arrangement of simulators, the oilfield simulation may be selected to provide the desired results. Various combinations may be tried and compared to determine the best outcome. Adjustments to the oilfield simulation may be made based on the oilfield, the simulators, the arrangement and other factors. The process may be repeated as desired.

It will be understood from the foregoing description that various modifications and changes may be made in the preferred and alternative embodiments of the present invention without departing from its true spirit. For example, the simulators, couplings, and arrangement of the system may be selected to achieve the desired simulation. The simulations may be repeated according to the various configurations, and the results compared and/or analyzed. The uncertainty parameters may be modeled in many different ways resulting in various different number of model realizations. The performance measure and estimated performance may be formulated as desired depending on the associated decision making process.

This description is intended for purposes of illustration only and should not be construed in a limiting sense. The scope of this invention should be determined only by the language of the claims that follow. The term "comprising" within the claims is intended to mean "including at least" such that the recited listing of elements in a claim are an open group. "A," "an" and other singular terms are intended to include the plural forms thereof unless specifically excluded.

What is claimed is:

1. A method for performing operations of an oilfield having at least one process facility and at least one wellsite operatively connected thereto, each at least one wellsite having a wellbore penetrating a subterranean formation for extracting fluid from or injecting fluid to an underground reservoir therein, the method comprising:

selectively coupling a plurality of oilfield simulators comprising a first oilfield simulator and a second oilfield simulator according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein the first oilfield simulator inputs an oilfield control parameter;

coupling a production system to the plurality of oilfield simulators, wherein the production system receives data collected during the operations of the oilfield;

identifying, an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein the second oilfield simulator inputs the uncertainty parameter;

modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter;

identifying, using the plurality of oilfield simulators configured in an optimization loop, an optimal value of the oilfield control parameter based on the estimated performance;

monitoring, using the production system coupled to the plurality of oilfield simulators, the operations of the oilfield performed in a monitoring loop to monitor the data collected during the operations of the oilfield, wherein the operations of the oilfield is performed using the optimal value of the oilfield control parameter;

detecting a deviation between the operations of the oilfield and an optimal estimated performance to generate a monitoring result, wherein the optimal estimated performance is determined from the optimal value of the oilfield control parameter;

receiving, in response to the deviation exceeding a predetermined criterion, an adjusted weighted probability of the at least one of the plurality of probable values of the uncertainty parameter;

determining, by selectively communicating between the plurality of oilfield simulators, an adjusted optimal value of the oilfield control parameter based on the adjusted weighted probability; and

modifying the operations of the oilfield based on the adjusted optimal value of the oilfield control parameter.

2. The method of claim **1**,

wherein at least one of the plurality of oilfield simulators receives data from sensors positioned about the oilfield,

wherein the sensors measure parameters of the operations of the oilfield, and

wherein the parameters comprise the oilfield control parameter.

3. The method of claim **1**,

wherein the oilfield control parameter comprises at least one selected from a group consisting of liquid-flow rate, flow-head pressure, and trigger action parameter, and

wherein the uncertainty parameter comprises at least one selected from a group consisting of pore volume, fault transmissibility, permeability, porosity, productivity, oil price, and discount rate.

4. The method of claim **1**, further comprising:

assessing economics of the operations of the oilfield based on the optimal value of the oilfield control parameter,

wherein the estimated performance is generated based on a net present value function of the plurality of oilfield simulators.

5. The method of claim **1**,

wherein the operations of the oilfield is modeled n^m times for the predetermined value of the oilfield control parameter,

wherein the uncertainty parameter is one of a plurality of uncertainty parameters, m representing a number of the plurality of uncertainty parameters,

wherein n represents a number of the plurality of probable values of the uncertainty parameter, and

wherein the operations of the oilfield is modeled concurrently for at least a portion of the n^m times.

6. The method of claim **1**, further comprising:

performing analysis according to the monitoring result, wherein the analysis is performed by selectively communicating between the plurality of oilfield simulators in an analysis loop; and

adjusting based on the analysis at least one selected from a group consisting of a criteria for generating the monitoring result, a constraint associated with the operations of the oilfield, the oilfield control parameter, and the uncertainty parameter.

7. The method of claim **1**, wherein the oilfield operation is an injection operation comprising at least one selected from a group consisting of water injection, natural gas injection, polymer injection, steam injection, carbon dioxide injection, surfactant injection, Miscible Water Alternating Gas (MWAG) injection, and combinations thereof.

8. A method for performing operations of an oilfield having at least one process facility and at least one wellsite operatively connected thereto, each at least one wellsite having a wellbore penetrating a subterranean formation for extracting fluid from or injecting fluid to an underground reservoir therein, the method comprising:

selectively coupling a plurality of oilfield simulators comprising a first oilfield simulator and a second oilfield simulator according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein the first oilfield simulator inputs an oilfield control parameter;

coupling a production system to the plurality of oilfield simulators, wherein the production system receives data collected during the operations of the oilfield;

identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein the second oilfield simulator inputs the uncertainty parameter;

modeling the operations of the oilfield to generate a first estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a first predetermined value of the oilfield control parameter and a first probable value of the plurality of probable values of the uncertainty parameter;

modeling the operations of the oilfield to generate a second estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a second predetermined value of the oilfield control parameter and a second probable value of the plurality of probable values of the uncertainty parameter;

identifying, using the plurality of oilfield simulators configured in an optimization loop, an optimal value of the oilfield control parameter by comparing the first estimated performance and the second estimated performance;

monitoring, using the production system coupled to the plurality of oilfield simulators, the operations of the oilfield performed in a monitoring loop to monitor the data collected during the operations of the oilfield, wherein the operations of the oilfield is performed using the optimal value of the oilfield control parameter;

detecting a deviation between the operations of the oilfield and an optimal estimated performance to generate a monitoring result, wherein the optimal estimated performance is determined from the optimal value of the oilfield control parameter;

receiving, in response to the deviation exceeding a predetermined criterion, an adjusted weighted probability of the at least one of the plurality of probable values of the uncertainty parameter;

determining, by selectively communicating between the plurality of oilfield simulators, an adjusted optimal value of the oilfield control parameter based on the adjusted weighted probability; and

modifying the operations of the oilfield based on the adjusted optimal value of the oilfield control parameter.

9. The method of claim **8**, wherein the first estimated performance and the second estimated performance are generated concurrently.

10. The method of claim **8**,

wherein at least one of the plurality of oilfield simulators receives data from sensors positioned about the oilfield,

wherein the sensors measure parameters of the operations of the oilfield, and

wherein the parameters comprise the oilfield control parameter.

11. The method of claim **8**,

wherein the oilfield control parameter comprises at least one selected from a group consisting of liquid-flow rate, flow-head pressure, and trigger action parameter, and

wherein the uncertainty parameter comprises at least one selected from a group consisting of pore volume, fault transmissibility, permeability, porosity, productivity, oil price, and financial uncertainty.

12. The method of claim **8**,

wherein the plurality of oilfield simulators comprise at least one selected from a group consisting of a reservoir simulator, a wellbore simulator, a surface network simulator, a process simulator, and an economics simulator.

13. The method of claim **8**, further comprising:

performing analysis according to the monitoring result, wherein the analysis is performed by selectively communicating between the plurality of oilfield simulators in an analysis loop; and

adjusting based on the analysis at least one selected from a group consisting of a criteria for generating the monitoring result, a constraint associated with the operations of the oilfield, the oilfield control parameter, and the uncertainty parameter.

14. A method for performing operations of an oilfield having at least one process facility and at least one wellsite operatively connected thereto, each at least one wellsite having a wellbore penetrating a subterranean formation for extracting fluid from or injecting fluid to an underground reservoir therein, the method comprising:

selectively coupling a plurality of oilfield simulators comprising a first oilfield simulator and a second oilfield simulator according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein the first oilfield simulator inputs an oilfield control parameter;

coupling a production system to the plurality of oilfield simulators, wherein the production system receives data collected during the operations of the oilfield;

identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein the second oilfield simulator inputs the uncertainty parameter;

modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter;

identifying, using the plurality of oilfield simulators configured in an optimization loop, an optimal value of the oilfield control parameter based on the estimated performance;

selecting a risk aversion factor represented by a parameter λ, wherein the estimated performance comprises a parameterized function F_λ based on λ, wherein the optimal value of the oilfield control parameter is a function of λ;

determining a desired risk aversion factor based on the parameterized function F_λ;

performing the operations of the oilfield based on the desired risk aversion factor;

monitoring, using the production system coupled to the plurality of oilfield simulators, the operations of the oilfield performed in a monitoring loop to monitor the data collected during the operations of the oilfield, wherein the operations of the oilfield is performed using the optimal value of the oilfield control parameter;

detecting a deviation between the operations of the oilfield and an optimal estimated performance to generate a monitoring result, wherein the optimal estimated performance is determined from the optimal value of the oilfield control parameter;

receiving, in response to the deviation exceeding a predetermined criterion, an adjusted weighted probability of the at least one of the plurality of probable values of the uncertainty parameter;

determining, by selectively communicating between the plurality of oilfield simulators, an adjusted optimal value of the oilfield control parameter based on the adjusted weighted probability; and

modifying the operations of the oilfield based on the adjusted optimal value of the oilfield control parameter.

15. The method of claim **14**,

wherein $F_\lambda=\mu-\lambda*\sigma$,

wherein μ represents a weighted average of a performance measure generated by the plurality of oilfield simulators based on the plurality of probable values of the uncertainty parameter, and

wherein σ represents a standard deviation of the performance measure.

16. The method of claim **14**,

wherein at least one of the plurality of oilfield simulators receives data from sensors positioned about the oilfield,

wherein the sensors measure parameters of the operations of the oilfield,

wherein the parameters comprises the oilfield control parameter,

wherein the oilfield control parameter comprises at least one selected from a group consisting of liquid-flow rate, flow-head pressure, and trigger action parameter, and

wherein the uncertainty parameter comprises at least one selected from a group consisting of pore volume, fault transmissibility, permeability, porosity, productivity, oil price, and discount rate.

17. The method of claim **14**, further comprising:

performing analysis according to the monitoring result, wherein the analysis is performed by selectively communicating between the plurality of oilfield simulators in an analysis loop; and

adjusting based on the analysis at least one selected from a group consisting of a criteria for generating the moni-

toring result, a constraint associated with the operations of the oilfield, the oilfield control parameter, and the uncertainty parameter.

18. A non-transitory computer readable storage medium, embodying instructions executable by a computer to perform method steps for performing operations of an oilfield having a subterranean formation with at least one reservoir positioned therein, the instructions comprising functionality for:

selectively coupling a plurality of oilfield simulators comprising a first oilfield simulator and a second oilfield simulator according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein the first oilfield simulator inputs an oilfield control parameter;

coupling a production system to the plurality of oilfield simulators, wherein the production system receives data collected during the operations of the oilfield;

identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein the second oilfield simulator inputs the uncertainty parameter;

modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter;

identifying, using the plurality of oilfield simulators configured in an optimization loop, an optimal value of the oilfield control parameter based on the estimated performance;

monitoring, using the production system coupled to the plurality of oilfield simulators, the operations of the oilfield performed in a monitoring loop to monitor the data collected during the operations of the oilfield, wherein the operations of the oilfield is performed using the optimal value of the oilfield control parameter;

detecting a deviation between the operations of the oilfield and an optimal estimated performance to generate a monitoring result, wherein the optimal estimated performance is determined from the optimal value of the oilfield control parameter;

receiving, in response to the deviation exceeding a predetermined criterion, an adjusted weighted probability of the at least one of the plurality of probable values of the uncertainty parameter;

determining, by selectively communicating between the plurality of oilfield simulators, an adjusted optimal value of the oilfield control parameter based on the adjusted weighted probability; and

modifying the operations of the oilfield based on the adjusted optimal value of the oilfield control parameter.

19. A non-transitory computer readable storage medium, embodying instructions executable by a computer to perform method steps for performing operations of an oilfield having a subterranean formation with at least one reservoir positioned therein, the instructions comprising functionality for:

selectively coupling a plurality of oilfield simulators comprising a first oilfield simulator and a second oilfield simulator according to a predefined configuration, each oilfield simulator modeling at least a portion of the oilfield, wherein the first oilfield simulator inputs an oilfield control parameter;

coupling a production system to the plurality of oilfield simulators, wherein the production system receives data collected during the operations of the oilfield;

identifying an uncertainty parameter associated with a plurality of probable values each corresponding to a weighted probability, wherein the second oilfield simulator inputs the uncertainty parameter;

modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the plurality of oilfield simulators, wherein the operations of the oilfield is modeled with a predetermined value of the oilfield control parameter and at least one of the plurality of probable values of the uncertainty parameter;

identifying, using the plurality of oilfield simulators configured in an optimization loop, an optimal value of the oilfield control parameter based on the estimated performance;

selecting a risk aversion factor represented by a parameter λ, wherein the estimated performance comprises a parameterized function F_λ based on λ, wherein the optimal value of the oilfield control parameter is a function of λ;

determining a desired risk aversion factor based on the parameterized function F_λ;

performing the operations of the oilfield based on the desired risk aversion factor;

monitoring, using the production system coupled to the plurality of oilfield simulators, the operations of the oilfield performed in a monitoring loop to monitor the data collected during the operations of the oilfield, wherein the operations of the oilfield is performed using the optimal value of the oilfield control parameter;

detecting a deviation between the operations of the oilfield and an optimal estimated performance to generate a monitoring result, wherein the optimal estimated performance is determined from the optimal value of the oilfield control parameter;

receiving, in response to the deviation exceeding a predetermined criterion, an adjusted weighted probability of the at least one of the plurality of probable values of the uncertainty parameter;

determining, by selectively communicating between the plurality of oilfield simulators, an adjusted optimal value of the oilfield control parameter based on the adjusted weighted probability; and

modifying the operations of the oilfield based on the adjusted optimal value of the oilfield control parameter.

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