US 20050199391A1

(19) United States
(12) Patent Application Publication
Cudmore et al.
(10) Pub. No.: US 2005/0199391 A1
(43) Pub. Date: Sep. 15, 2005

(54) SYSTEM AND METHOD FOR OPTIMIZING PRODUCTION IN AN ARTIFICIALLY LIFTED WELL

(76) Inventors: **Julian R. Cudmore**, Inverurie (GB); **Julian B. Haskell**, Peterculter (GB); **Thomas M. White**, Spring, TX (US)

Correspondence Address:
Schlumberger Technology Corporation
Schlumberger Reservoir Completions
14910 Airline Road
P.O. Box 1590
Rosharon, TX 77583-1590 (US)

(21) Appl. No.: **10/771,065**

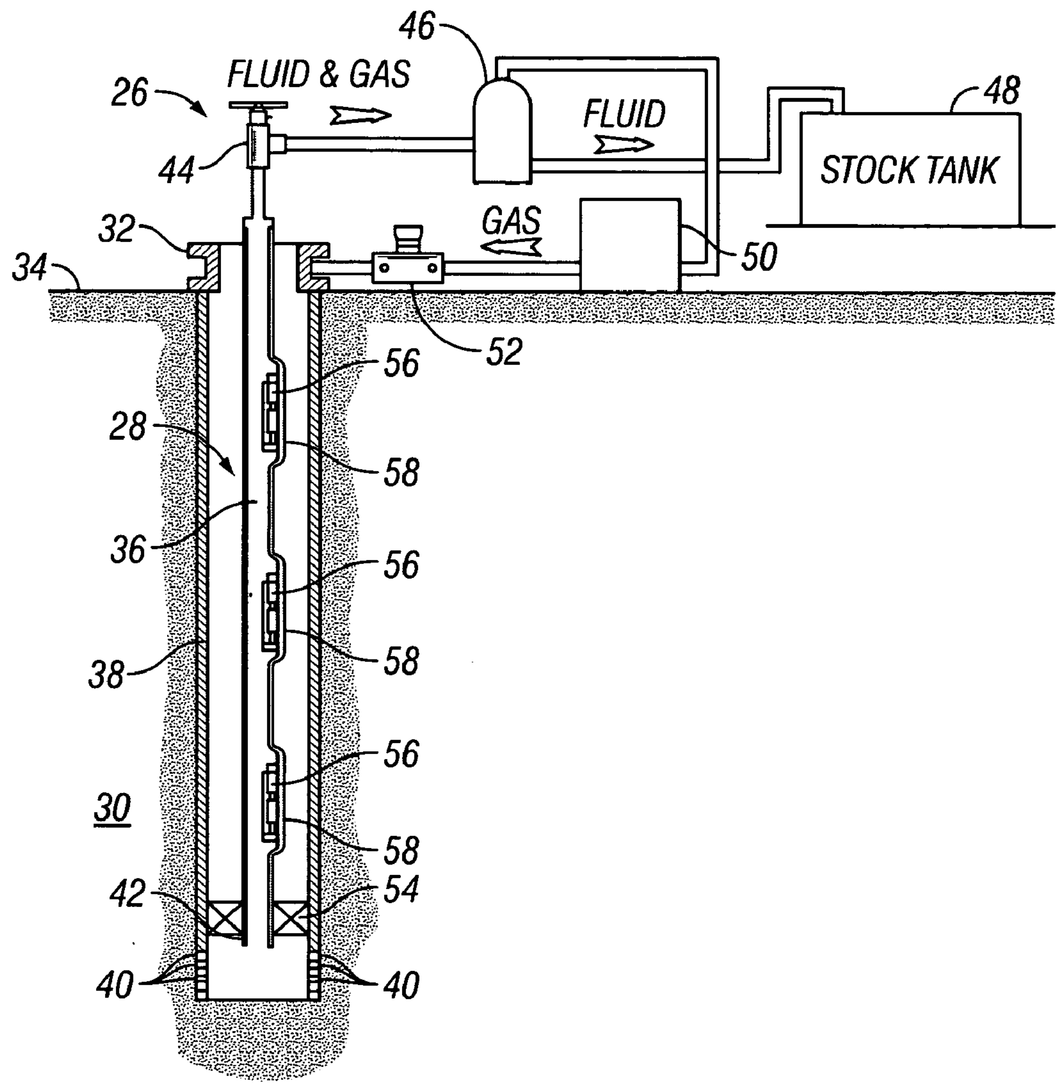
(22) Filed: **Feb. 3, 2004**

Publication Classification

(51) Int. Cl.[7] **E21B 43/00**
(52) U.S. Cl. **166/250.15**; 166/372; 166/68; 166/66

(57) **ABSTRACT**

A system and method is provided for optimizing production from a well. A plurality of sensors are positioned to sense a variety of production related parameters in a well having a gas lift system. The sensed parameters are used in creating measured data that can be applied against a well model. Discrepancies between the well model and the measured data are used to determine factors contributing to sub-optimal well performance.



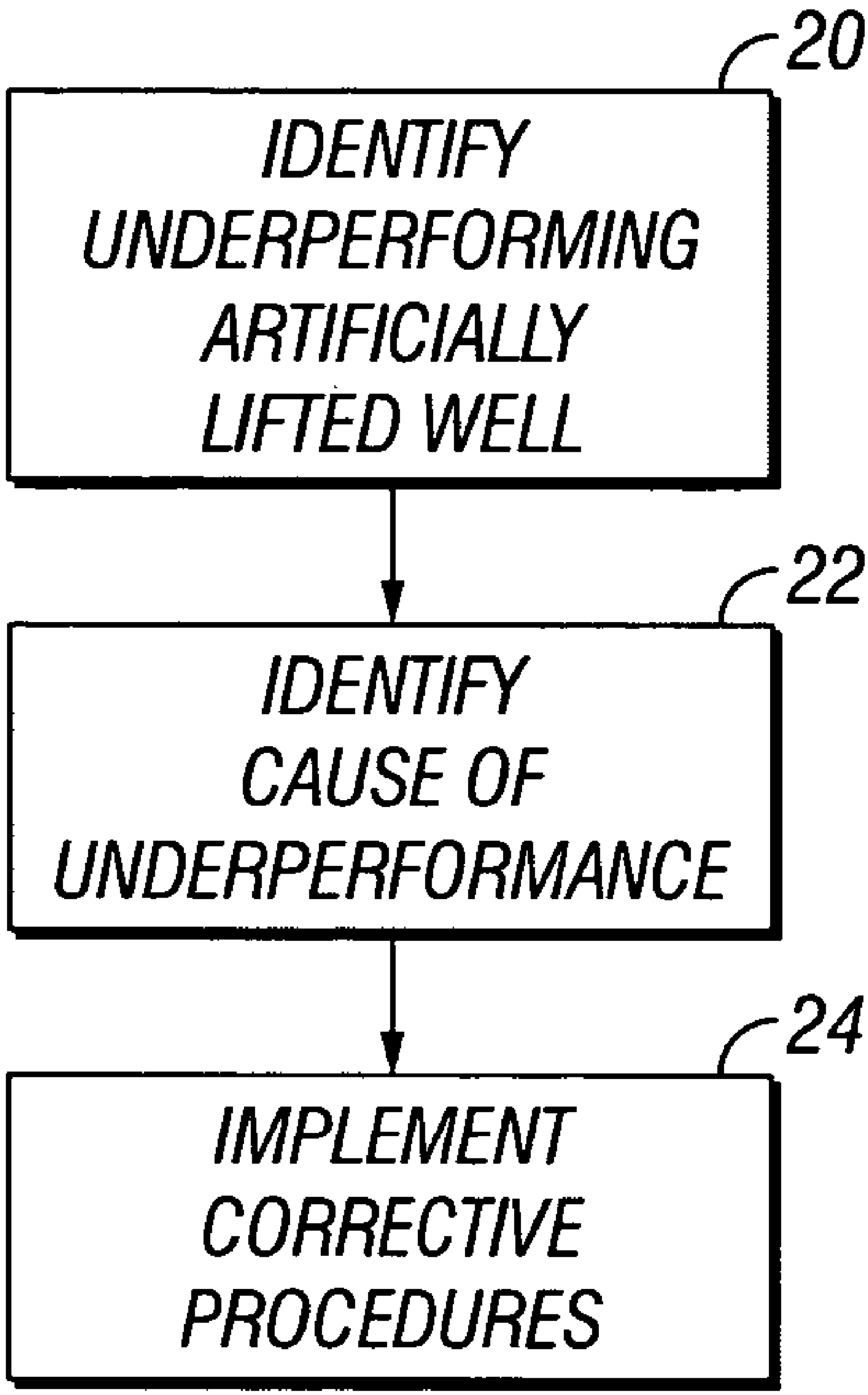
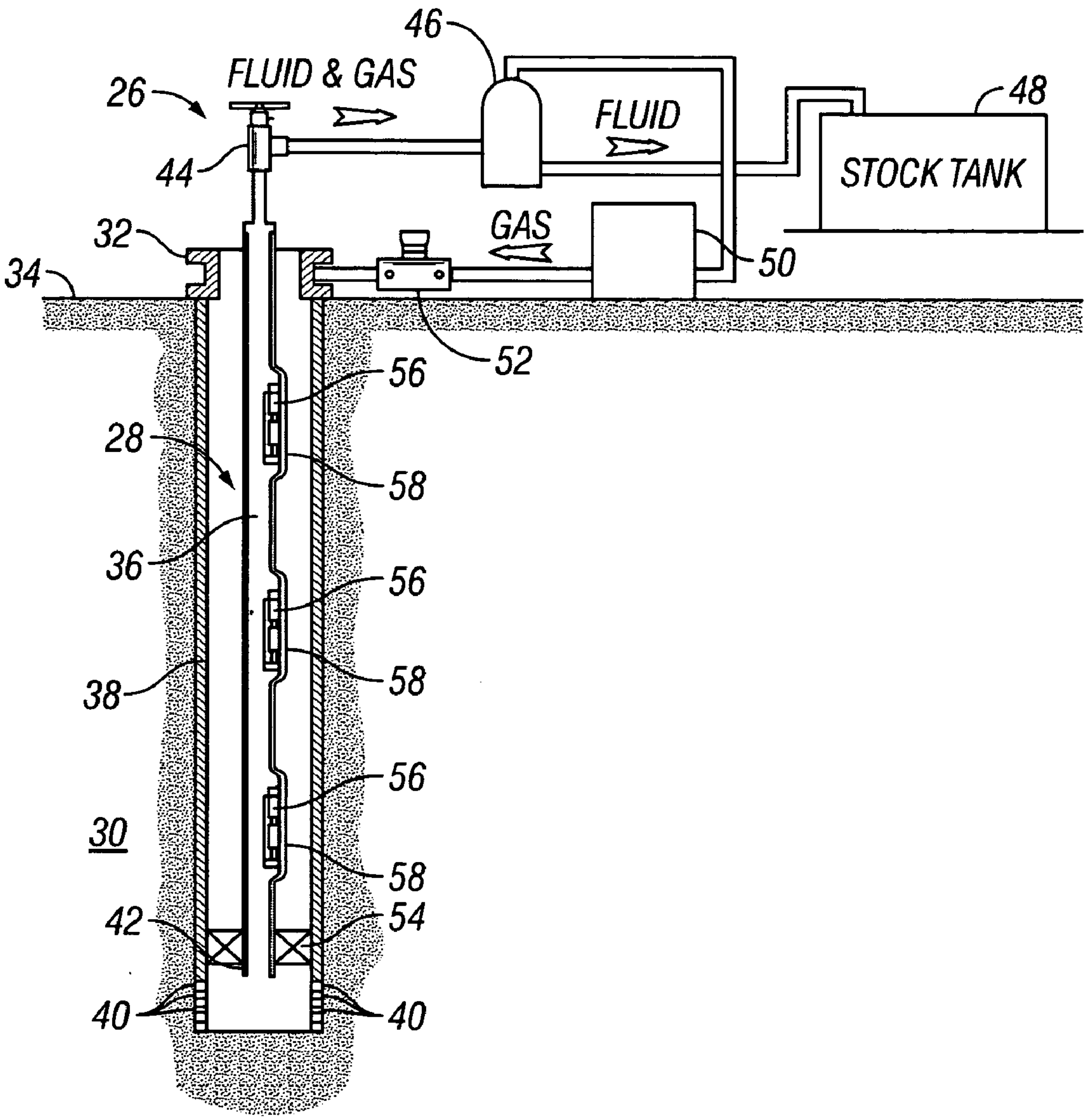

20
IDENTIFY UNDERPERFORMING ARTIFICIALLY LIFTED WELL
22
IDENTIFY CAUSE OF UNDERPERFORMANCE
24
IMPLEMENT CORRECTIVE PROCEDURES

FIG. 1



46
FLUID & GAS
26
48
FLUID
44
STOCK TANK
GAS
32
34
50
52
56
28
58
36
56
38
58
56
30
58
42
54
40
40

FIG. 2

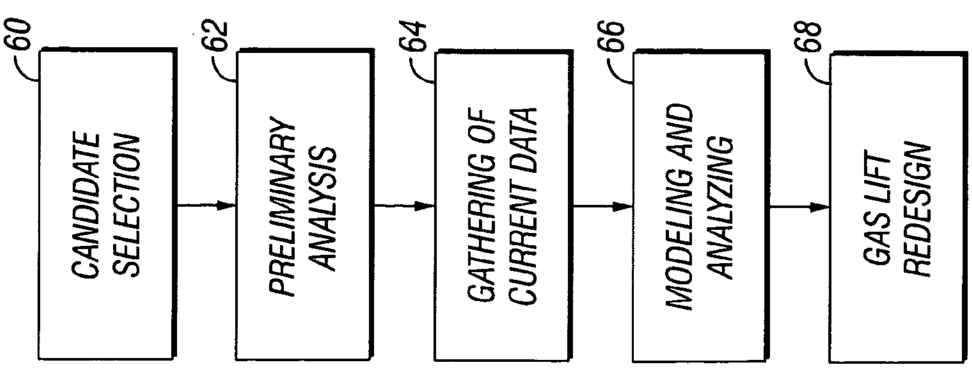


FIG. 3

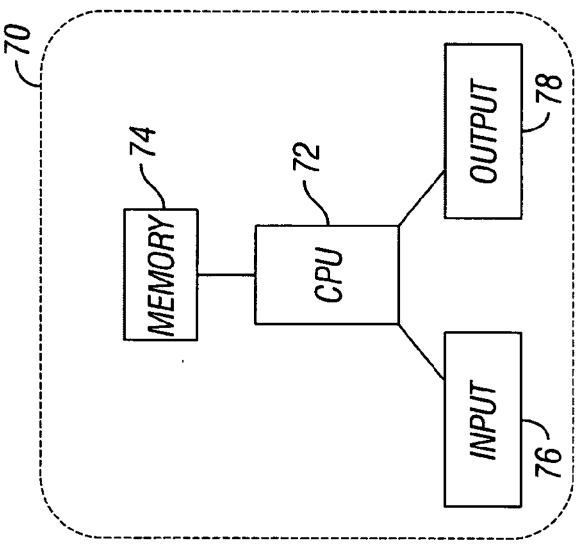


FIG. 4

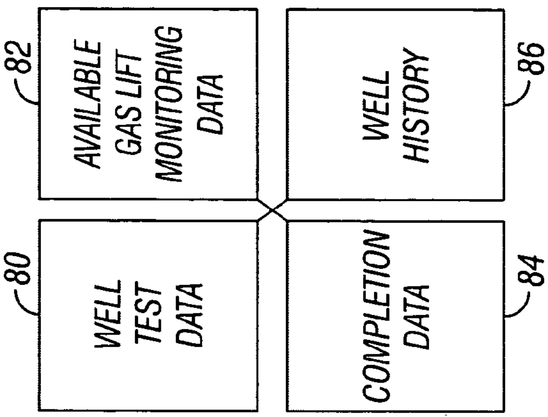
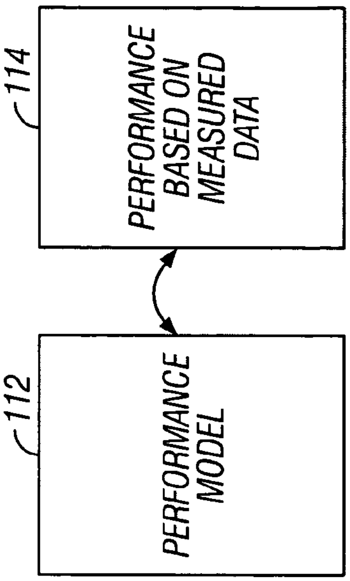
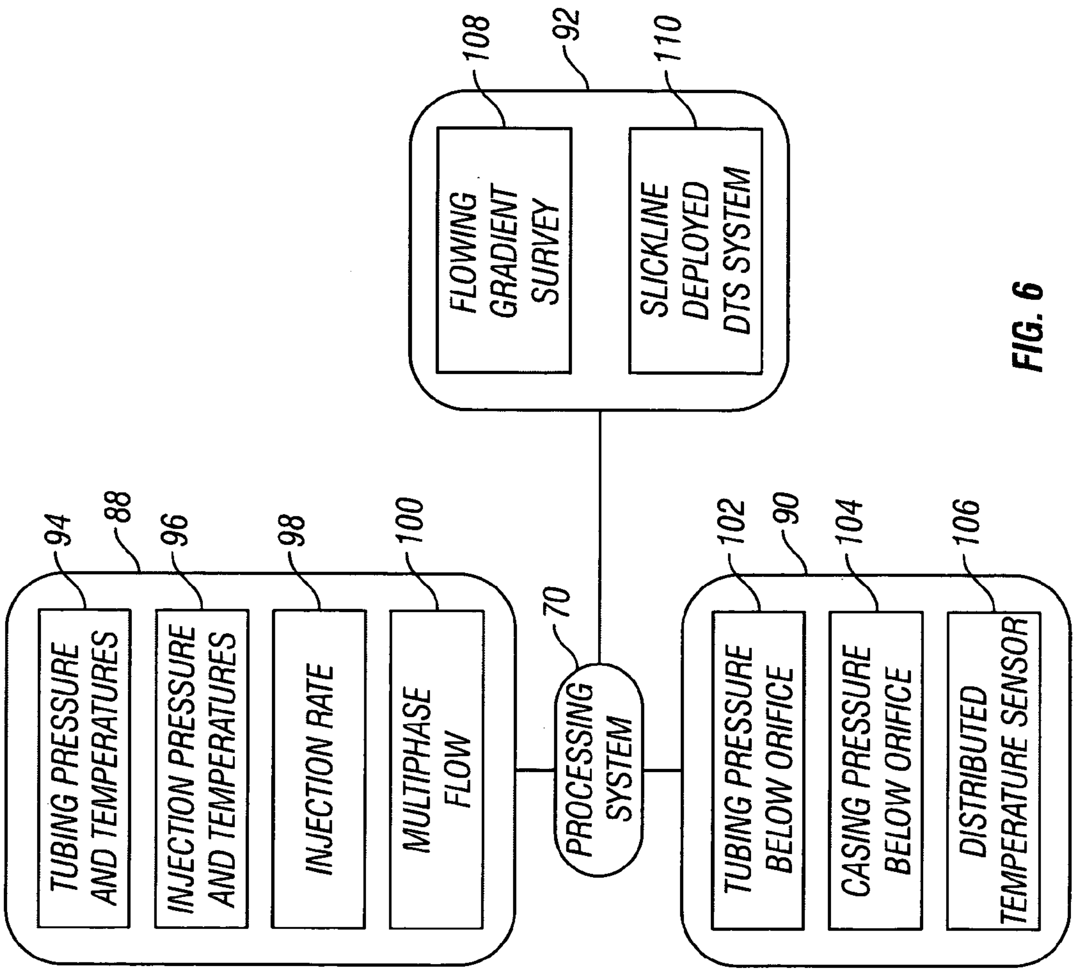


FIG. 5



PERFORMANCE MODEL
112
PERFORMANCE BASED ON MEASURED DATA
114

FIG. 7



TUBING PRESSURE AND TEMPERATURES
94
88
INJECTION PRESSURE AND TEMPERATURES
96
INJECTION RATE
98
MULTIPHASE FLOW
100
PROCESSING SYSTEM
70
TUBING PRESSURE BELOW ORIFICE
102
90
CASING PRESSURE BELOW ORIFICE
104
DISTRIBUTED TEMPERATURE SENSOR
106
FLOWING GRADIENT SURVEY
108
92
SLICKLINE DEPLOYED DTS SYSTEM
110

FIG. 6

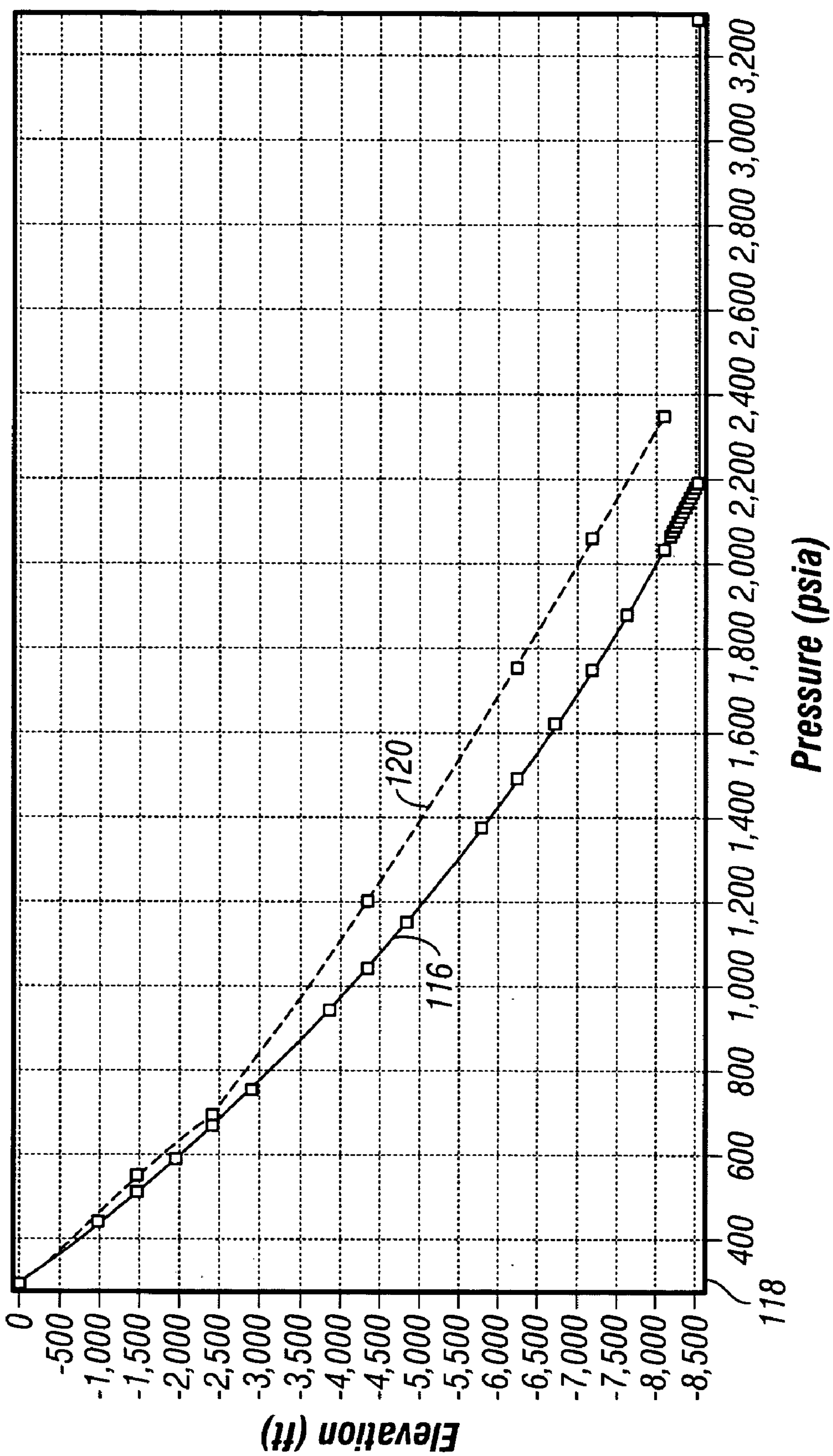

Elevation (ft)
0
-500
-1,000
-1,500
-2,000
-2,500
-3,000
-3,500
-4,000
-4,500
-5,000
-5,500
-6,000
-6,500
-7,000
-7,500
-8,000
-8,500
Pressure (psia)
400
600
800
1,000
1,200
1,400
1,600
1,800
2,000
2,200
2,400
2,600
2,800
3,000
3,200
116
118
120

FIG. 8

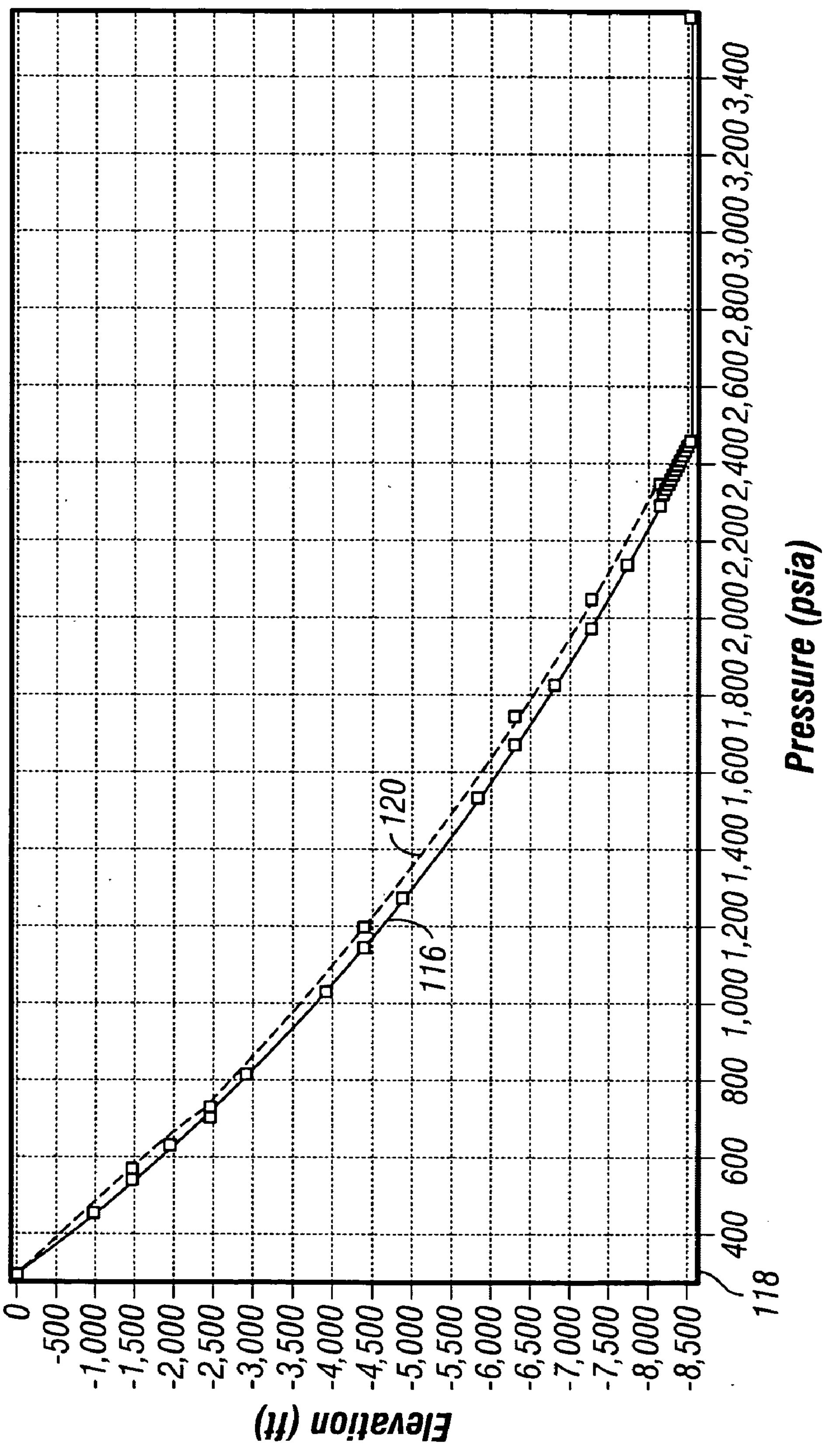

Elevation (ft)
0
-500
-1,000
-1,500
-2,000
-2,500
-3,000
-3,500
-4,000
-4,500
-5,000
-5,500
-6,000
-6,500
-7,000
-7,500
-8,000
-8,500
Pressure (psia)
400
600
800
1,000
1,200
1,400
1,600
1,800
2,000
2,200
2,400
2,600
2,800
3,000
3,200
3,400
116
118
120

FIG. 9

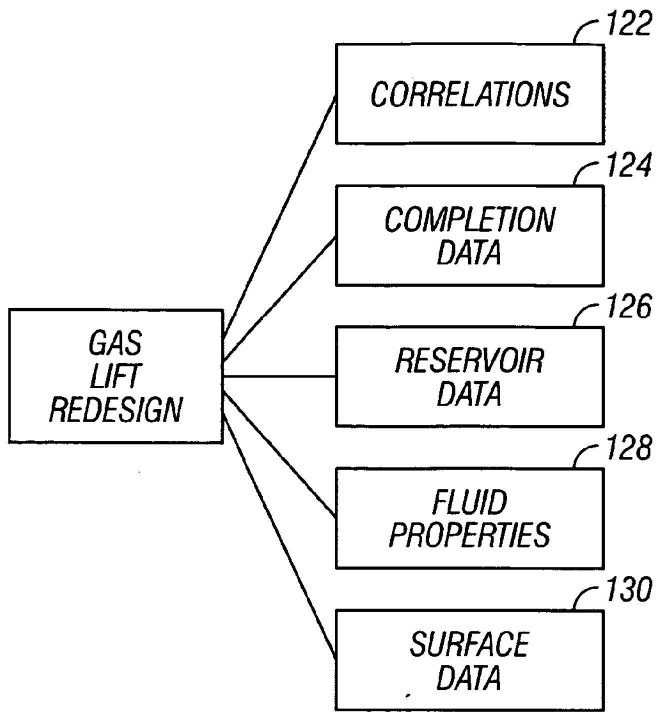


FIG. 10

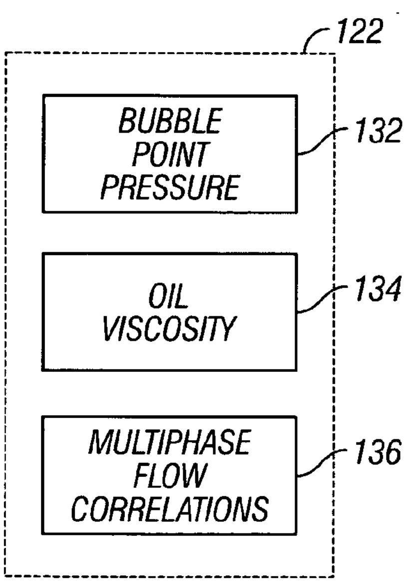


FIG. 11

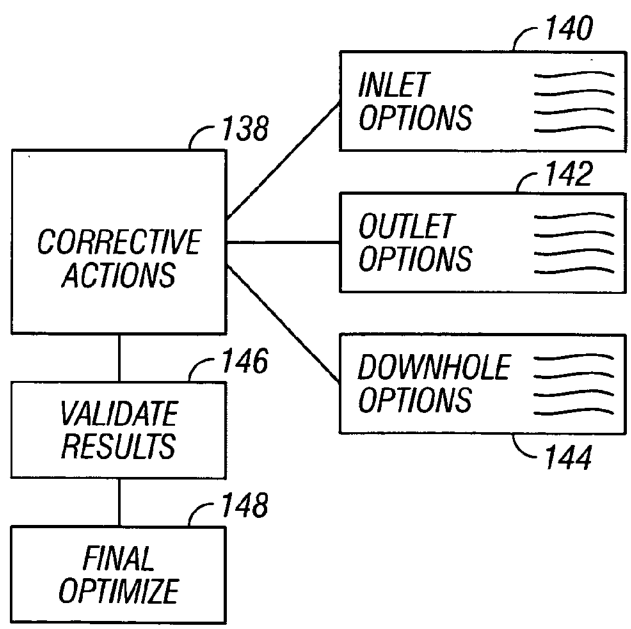


FIG. 12

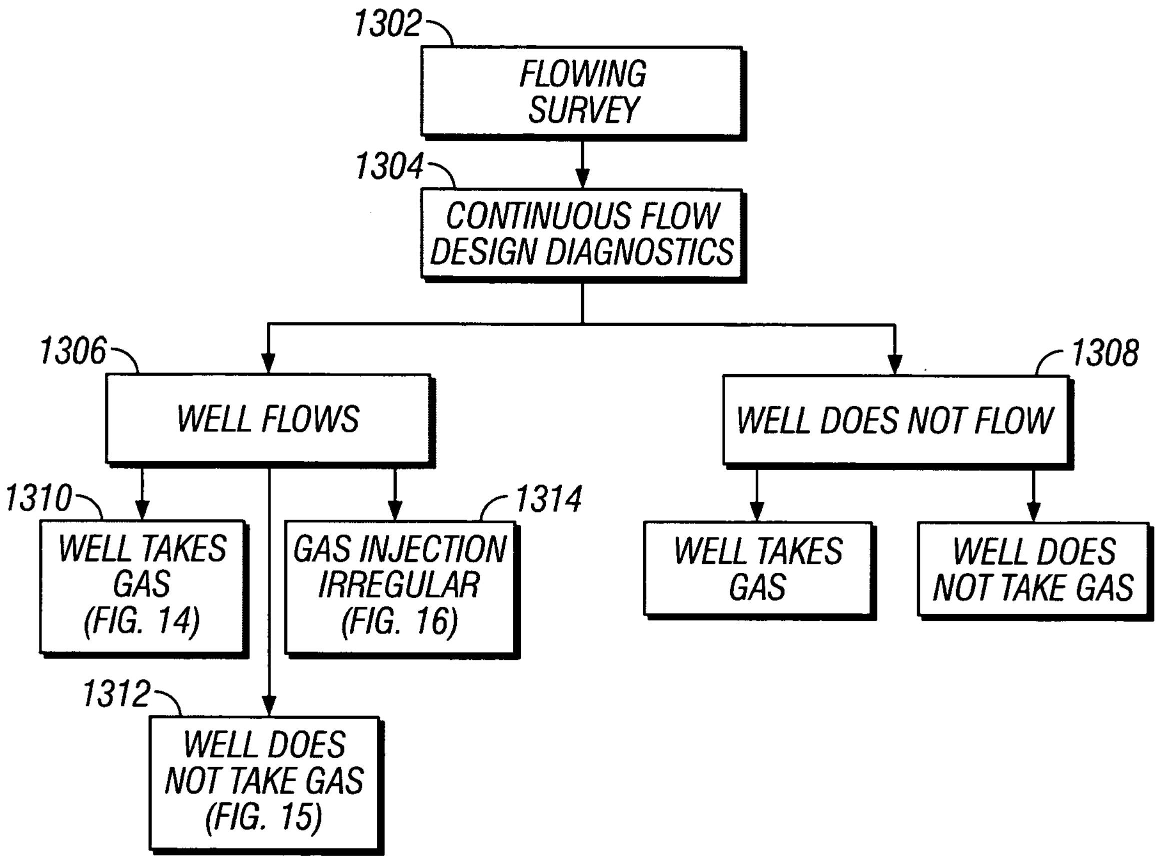

1302
FLOWING SURVEY
1304
CONTINUOUS FLOW DESIGN DIAGNOSTICS
1306
WELL FLOWS
1308
WELL DOES NOT FLOW
1310
WELL TAKES GAS (FIG. 14)
1314
GAS INJECTION IRREGULAR (FIG. 16)
WELL TAKES GAS
WELL DOES NOT TAKE GAS
1312
WELL DOES NOT TAKE GAS (FIG. 15)

FIG. 13

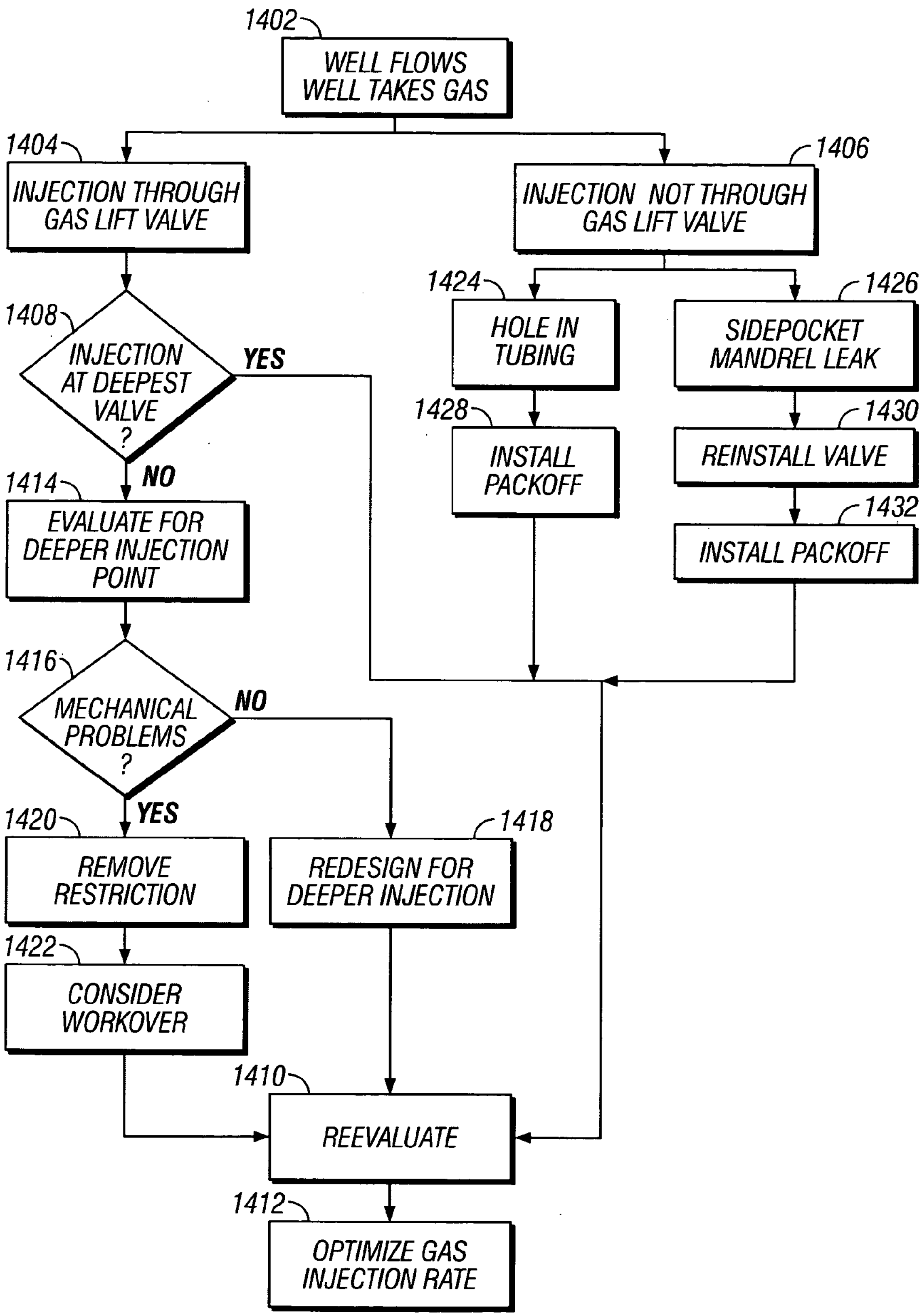

1402
WELL FLOWS
WELL TAKES GAS
1404
INJECTION THROUGH GAS LIFT VALVE
1406
INJECTION NOT THROUGH GAS LIFT VALVE
1408
INJECTION AT DEEPEST VALVE ?
YES
NO
1424
HOLE IN TUBING
1426
SIDEPOCKET MANDREL LEAK
1428
INSTALL PACKOFF
1430
REINSTALL VALVE
1432
INSTALL PACKOFF
1414
EVALUATE FOR DEEPER INJECTION POINT
1416
MECHANICAL PROBLEMS ?
NO
YES
1420
REMOVE RESTRICTION
1418
REDESIGN FOR DEEPER INJECTION
1422
CONSIDER WORKOVER
1410
REEVALUATE
1412
OPTIMIZE GAS INJECTION RATE

FIG. 14

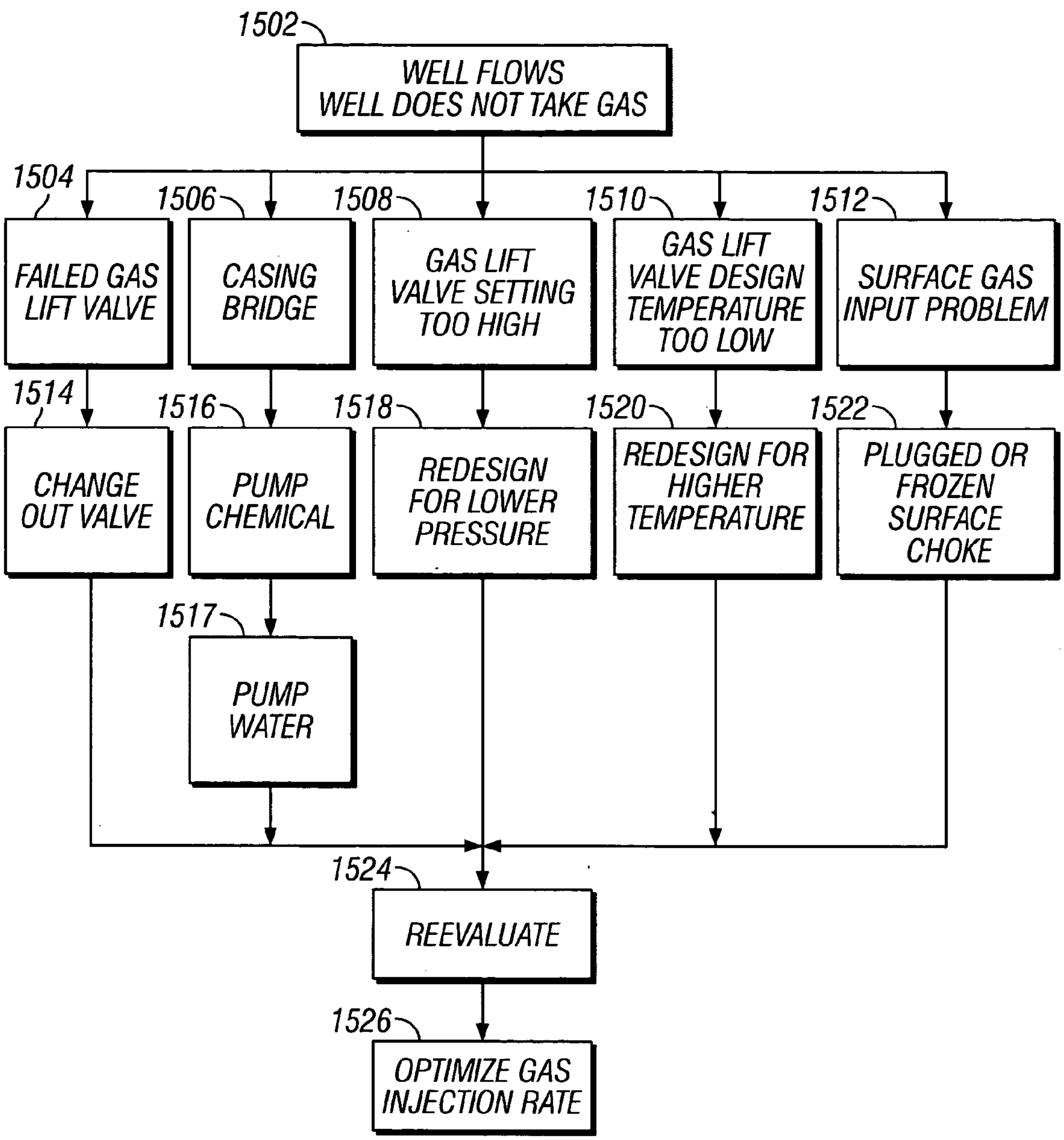

1502
WELL FLOWS
WELL DOES NOT TAKE GAS
1504
FAILED GAS LIFT VALVE
1506
CASING BRIDGE
1508
GAS LIFT VALVE SETTING TOO HIGH
1510
GAS LIFT VALVE DESIGN TEMPERATURE TOO LOW
1512
SURFACE GAS INPUT PROBLEM
1514
CHANGE OUT VALVE
1516
PUMP CHEMICAL
1518
REDESIGN FOR LOWER PRESSURE
1520
REDESIGN FOR HIGHER TEMPERATURE
1522
PLUGGED OR FROZEN SURFACE CHOKE
1517
PUMP WATER
1524
REEVALUATE
1526
OPTIMIZE GAS INJECTION RATE

FIG. 15

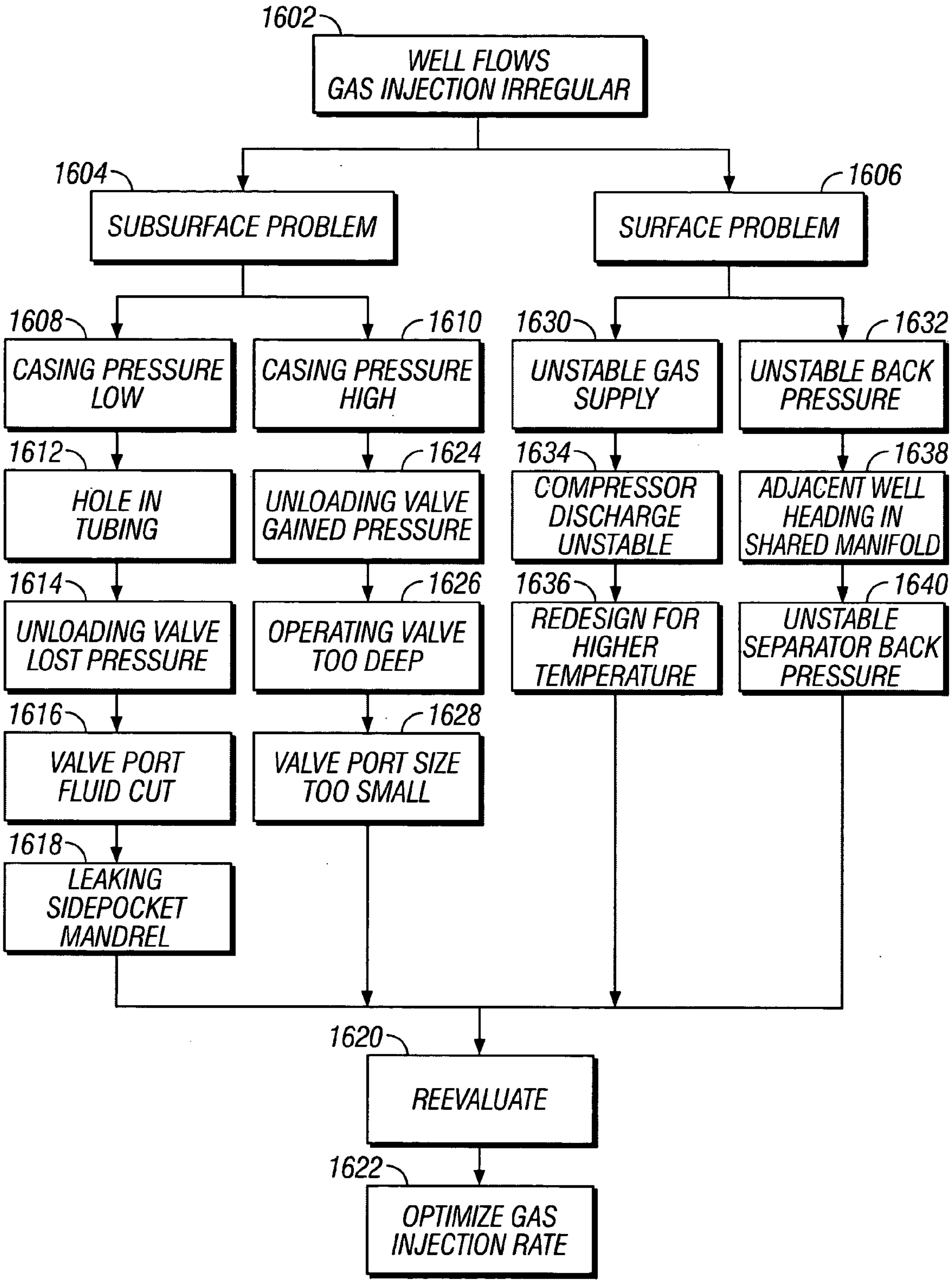

1602
WELL FLOWS GAS INJECTION IRREGULAR
1604
SUBSURFACE PROBLEM
1606
SURFACE PROBLEM
1608
CASING PRESSURE LOW
1610
CASING PRESSURE HIGH
1630
UNSTABLE GAS SUPPLY
1632
UNSTABLE BACK PRESSURE
1612
HOLE IN TUBING
1624
UNLOADING VALVE GAINED PRESSURE
1634
COMPRESSOR DISCHARGE UNSTABLE
1638
ADJACENT WELL HEADING IN SHARED MANIFOLD
1614
UNLOADING VALVE LOST PRESSURE
1626
OPERATING VALVE TOO DEEP
1636
REDESIGN FOR HIGHER TEMPERATURE
1640
UNSTABLE SEPARATOR BACK PRESSURE
1616
VALVE PORT FLUID CUT
1628
VALVE PORT SIZE TOO SMALL
1618
LEAKING SIDEPOCKET MANDREL
1620
REEVALUATE
1622
OPTIMIZE GAS INJECTION RATE

FIG. 16

SYSTEM AND METHOD FOR OPTIMIZING PRODUCTION IN AN ARTIFICIALLY LIFTED WELL

BACKGROUND OF THE INVENTION

[0001] 1. Field of the Invention

[0002] The present invention relates to artificially lifted oil and gas wells, and in particular to such wells employing gas lift technology.

[0003] 2. Description of Related Art

[0004] In many artificially lifted wells, there is potential for significantly improved operation and increased production. There are a variety of mechanisms for artificially lifting fluid from a reservoir, such as gas lift systems. In artificial lift systems, a variety of mechanical and systemic components can limit optimization of system usage. For example, gas injection rates may not be optimal and/or artificial lift system components may be blocked, damaged, sized improperly, operated at less than optimal rates, or otherwise present limitations on gaining optimal use of the overall system.

[0005] Attempts have been made to detect certain specific problems. However, comprehensive analysis of the well and/or system components has proved to be difficult once the system is moved downhole and placed into operation.

BRIEF SUMMARY OF THE INVENTION

[0006] In general, the present invention provides a system and method of optimizing production in a well having a gas lift system. The gas lift system is located and operated within a wellbore. Simultaneously, a plurality of production parameters are monitored and used to obtain certain desired, measured data indicative of well operational factors. The measured data are evaluated according to an optimization model to determine if production is optimized. If not, the gas lift mechanism is redesigned based on evaluation of the various production parameters and measured data.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] Certain embodiments of the invention will hereafter be described with reference to the accompanying drawings, wherein like reference numerals denote like elements, and:

[0008] **FIG. 1** is a schematic illustration of a methodology for optimizing production in a well, according to an embodiment of the present invention;

[0009] **FIG. 2** is an elevational view of a gas lift system utilized in a well to lift fluids to a surface location, according to an embodiment of the present invention;

[0010] **FIG. 3** is a flowchart representing a method of selecting and optimizing production in a well, according to an embodiment of the present invention;

[0011] **FIG. 4** is a diagramatic illustration of an embodiment of a control system that can be used to automatically carry out the methodology or portions of the methodology illustrated in **FIG. 3**;

[0012] **FIG. 5** is an illustration of parameters utilized in candidate selection;

[0013] **FIG. 6** is an illustration of a system that can be used to acquire data for use by the well optimization methodology illustrated in **FIG. 3**;

[0014] **FIG. 7** is an illustration of an embodiment of a well performance model;

[0015] **FIG. 8** is a graph representing a comparison of measured data to calculated data;

[0016] **FIG. 9** is a graph similar to that of **FIG. 8** but following redesign of the artificial lift system;

[0017] **FIG. 10** is a graphical representation of factors that can affect gas lift redesign;

[0018] **FIG. 11** is a graphical representation of correlation examples that can be used to facilitate gas lift redesign;

[0019] **FIG. 12** is a graphical representation of potential corrective actions that can be taken to optimize production from the well illustrated in **FIG. 2**;

[0020] **FIG. 13** is a flowchart illustrating a selected methodology of the present invention for optimizing gas injection rate;

[0021] **FIG. 14** is a flowchart illustrating a portion of the methodology of **FIG. 13** when the well flows and takes gas;

[0022] **FIG. 15** is a flowchart illustrating a portion of the methodology of **FIG. 13** when the well flows and does not take gas; and

[0023] **FIG. 16** is a flowchart illustrating a portion of the methodology of **FIG. 13** when the well flows and the gas injection is irregular.

DETAILED DESCRIPTION OF THE INVENTION

[0024] In the following description, numerous details are set forth to provide an understanding of the present invention. However, it will be understood by those of ordinary skill in the art that the present invention may be practiced without these details and that numerous variations or modifications from the described embodiments may be possible.

[0025] The present invention generally relates to a system and method for optimizing production from a well in which fluids are lifted by a gas lift system deployed in the well. The process allows the artificial lift system to be analyzed and diagnosed to facilitate system redesign that optimizes performance with respect to the productivity of the well.

[0026] A general approach to optimization is set forth in the flowchart of **FIG. 1**. Initially, underperforming, artificially lifted wells are identified, as set forth in block **20**. Upon determining the underperforming wells, the cause of the underperformance is identified, as illustrated by block **22**. Identification of the cause of the underperformance enables the implementation of corrective procedures, e.g. gas lift redesign, as illustrated in block **24**. Effectively, a cause or problem is identified and an effect or correction is undertaken to optimize performance. Depending on the environment and the specific equipment used, the causes and the selected effects, i.e., corrective actions, may vary as discussed more fully below.

[0027] Although this general approach can be applied to a variety of artificially lifted wells, the present description will primarily be related to the optimization of a well in which a gas lift system is used to artificially lift the well fluid. In **FIG. 2**, an embodiment of a gas lift system **26** is illustrated. In this embodiment, gas lift system **26** is used to produce fluid from a wellbore **28** drilled or otherwise formed in a geological formation **30**. A wellbore section of the gas lift system **26** is suspended below a wellhead **32** disposed, for example, at a surface **34** of the earth. A tubing **36** provides a flow path within wellbore **28** through which well fluid is produced to wellhead **32**.

[**0028**] As illustrated, wellbore **28** is lined with a wellbore casing **38** having perforations **40** through which fluid flows from formation **30** into wellbore **28**. For example, a hydrocarbon-based fluid may flow from formation **30** through perforations **40** and into wellbore **28** adjacent an intake **42** of tubing **36**. Upon entering wellbore **28**, the well fluid is produced upwardly by gas lift system **26** through tubing **36** to wellhead **32**. From wellhead **32**, the produced well fluid is directed through control valve **44** to a separator **46** where gas and liquid are separated. The substantially liquid portion of well fluid is directed to a desired location, such as stock tank **48**.

[**0029**] Although gas lift system **26** may comprise a wide variety of components, the example in **FIG. 2** is illustrated as having a gas compressor **50** that receives an injection gas from a gas source, such as separator **46**. Gas compressor **50** forces the gas through a flow control valve **52**, through wellhead **32** and into the annulus between tubing **36** and casing **38**. A packer **54** is designed to seal the annulus around tubing **36**. (In the embodiment illustrated, packer **54** is disposed proximate intake **42**.) The pressurized gas flows through the annulus and is forced into the interior of tubing **36** through one or more gas lift valves **56** disposed in corresponding side pocket mandrels **58**. The gas flowing through gas lift valves **56** draws well fluid into intake **42** and upwardly through the interior of tubing **36**. The mixture of injected gas and well fluid move upwardly through control valve **44** and are separated at separator **46** which directs the well fluid to stock tank **48** and the injection gas back to gas compressor **50**.

[**0030**] One example of a methodology that can be used in optimizing production in a gas lifted well can be described with reference to the illustrated flowchart of **FIG. 3**. Initially, the candidate wells are selected based on an indication of underperformance (block **60**). In the selected well or wells, a preliminary analysis (block **62**) is made to verify the candidate well is not producing at an optimal level and is suitable for production optimization. Subsequently, data is acquired that will help gauge the performance of the gas lift system **26** (block **64**). The data is based on a variety of production related parameters that may be sensed or otherwise obtained. In many applications, the sensing of production related parameters in real-time substantially improves the accuracy and comprehensiveness of the "operational picture" used in analyzing potential problems that contribute to underperformance. Once the data is acquired, the well is modeled based on known parameters related to the well and the specific gas lift system. The modeled well can then be matched to measured data, e.g. data based on the sensed production parameters, as illustrated in block **66**. If the well is operating at a sub-optimal level, a gas lift redesign is implemented and validated (block **68**). It should be noted that although the gas lift system is a major factor in the outflow performance of a well, the lift system is codependent with other factors, such as reservoir inflow and surface system performance. Thus, the optimization methodology benefits from an understanding of well performance, including inflow, outflow and surface performance, in determining the cause of sub-optimal performance.

[**0031**] Some or all of the methodology outlined with reference to **FIG. 3** is automated via a processing system **70**, as diagramatically illustrated in **FIG. 4**. Processing system **70** may be a computer-based system having a central processing unit (CPU) **72**. CPU **72** is operatively coupled to a memory **74**, as well as an input device **76** and an output device **78**. Input device **76** may comprise a variety of devices, such as a keyboard, mouse, voice-recognition unit, touchscreen, other input devices, or combinations of devices. Output device **78** may comprise a visual and/or audio output device, such as a monitor having a graphical user interface. Additionally, the processing may be done on a single device or multiple devices located at the well, away from the well, or with some devices located at the well and other devices located remotely.

[**0032**] Processing system **70** can be used to input parameters regarding candidate selection. The system also can be used to receive data during the data acquisition phase, to model the well by comparing calculated or modeled values to measured data, and to facilitate gas lift redesign based on the measured data. However, it should be recognized that the design and implementation of processing system **70** can vary substantially from one application to another, and the desired interaction between processing system **70** and an optimization technician may vary based on design considerations and application constraints.

[**0033**] As briefly described with reference to **FIG. 3**, candidate wells are initially selected. In, for example, oilfields with high populations of gas lift systems, it is important that likely candidates for optimization are filtered from wells that are already running at optimum conditions and at optimum rates. In one approach, candidate selection may be used to filter out wells according to priority of potential oil production gain, thereby helping attain maximum success in a minimum timeframe. The recognition of sub-optimally lifted wells relative to other wells in the field is not a straightforward task and requires evaluation of various data and information.

[**0034**] The ability to determine likely candidates for optimization often relies on obtaining accurate data related to the subject wells. For example, it can be useful to monitor a data trend to determine the consistency and accuracy of the data relied on in determining likely candidates for optimization.

[**0035**] Also, it can be important to initially examine a variety of factors before selecting candidates for optimization. In **FIG. 5**, four candidate selection factors are illustrated, specifically, well test data **80**, available gas lift monitoring data **82**, completion data **84**, and well history **86**.

[**0036**] When interpreting existing well test data, it is beneficial to understand the accuracy level of the data and how it was acquired. Therefore, before selecting candidates it is helpful to examine any raw data related to production. For example, a differential pressure chart indicates the gas injection rate behavior, and a water cut reading of samples can indicate stability of the water cut. If the historical data is not consistent or cannot be logically analyzed, it may be necessary to test the well to establish "baseline" production values. After preliminary screening, the most prominent optimization candidates can be selected.

[0037] Available gas lift monitoring data also can affect candidate selection. During historical operation of a gas lift, certain parameters may be measured and values recorded on a periodic basis. Any of this monitoring data, e.g. gas injection rate, gas injection line pressure, casing head pressure, wellhead pressure, and wellhead temperature, can be helpful in assessing the potential for production optimization.

[0038] Completion data also is a factor that can affect the potential for production optimization. A review of a completion design diagram provides valuable information as to the gas lift configuration and specific downhole equipment used in the system. Such information may include depth and type of mandrels, type of gas lift valves, and port sizes. The configuration and equipment can help provide a better understanding of well behavior.

[0039] Well history data can also provide information that will aid in candidate selection. Well history data can include flowing gradient surveys, well intervention and stimulation information, records of chemical treatment, and other information that can help provide a basic understanding of the well. All of these factors can be used to reduce the subjectivity of the candidate selection process.

[0040] Upon selecting a candidate well, data is acquired to gauge the performance of the gas lift system. Typically, data is acquired by a variety of sensors that may comprise, for example, distributed temperature sensors and pressure sensors. Also, it can be beneficial to utilize sensor systems able to provide real-time streaming data. Trended data with common time and date facilitates the selection of points of interest from trend lines to provide more accurate "snap shots" of well operation to aid in analysis.

[0041] In **FIG. 6**, an embodiment of a sensor system used to facilitate optimization of a gas lift system is illustrated. The various sensors may be coupled to processing system **70** which is able to assimilate the data and display relevant information to a technician and/or utilize the data in performing analyses on the well. Although a variety of parameters may be sensed to provide measured data that can be used in analysis of a given well, **FIG. 6** illustrates examples of sensors and sensed parameters that may be helpful to the analysis. The sensed parameters are divided into three example groups, including surface measurements **88**, downhole measurements **90**, and episodic measurements **92**. Many of the sensed parameters can be obtained in real-time and delivered to processing system **70** for analysis. Processing system **70** can be located locally at the well or remotely. If located remotely, signals from the sensors can be transmitted to processing system **70** by hardwire or wirelessly, e.g. via satellite communication. Additionally, processing system **70** may comprise a single unit or multiple linked units.

[0042] Examples of surface sensors and/or sensed parameters include tubing pressure and temperature sensors **94**, injection pressure and temperature sensors **96**, injection sensors **98** for sensing the gas injection rate, and multiphase flow sensors **100**. Examples of downhole sensors and/or sensed parameters include tubing pressure sensors **102** disposed below the orifice, casing pressure sensors **104** disposed below the orifice, and distributed temperature sensors **106**. Examples of episodic sensors include sensors **108** for determining a flowing gradient survey and a deployable distributed temperature sensing (DTS) system **110** that may be deployed, for example, by a slickline. In other applications, it may be desirable to utilize additional sensors, other sensors, or smaller groups of sensors than those illustrated. For example, in some applications, the methodology discussed herein may be carried out with a unique subset of the illustrated sensors, such as sensors **94**, **96**, **98**, **100**, **108**, and **110**. Additionally, commercially available systems may be suitable to determine at least some of the measured data. An example of a commercially available system is the PhaseTester portable multiphase well testing system available from Schlumberger Technology Corporation of Sugar Land, Tex., USA.

[0043] In addition to acquiring data, the subject well and the gas lift system is modeled. However, modeling of the well will vary depending on the environment in which the wellbore is drilled, formation parameters, and type and componentry of the gas lift system. Proper modeling of the well enables comparison of calculated values (model values) to measured data based on the various production related parameters sensed or otherwise obtained. As illustrated in **FIG. 7**, a well performance modeling program **112** can be utilized on processor system **70** to match calculated or model values to the corresponding measured data **114** based on actual production related parameters, such as those described above with reference to **FIG. 6**.

[0044] A main philosophy in well modeling is the matching of a model well, e.g. optimized well, to measured data from the actual well to determine areas of sub-optimal performance. However, the more invalidated or unknown parameters used in the model, the greater the uncertainty and the greater the number of assumptions that must be used in the modeling. This, of course, increases the difficulty in matching the model with actual data in any meaningful way. Furthermore, the model and specific calculated data used to prepare a model for comparison to measured data can vary substantially depending on the well, wellbore environment, type of artificial lift equipment, and variety of lift system components. In preparing a well model, it can be helpful to utilize a modeling program on processing system **70**. One example that can be used in modeling gas lift systems is a software tool known as PIPESIM which provides steady-state, multiphase flow simulation for oil and gas production systems and is also available from Schlumberger Technology Corporation.

[0045] As briefly discussed above, real-time collection of data from a wide variety of sensors and the use of that data in assimilating measured data for comparison to a predetermined model lays important groundwork for optimization of a given well. Potentially, the performance modeling program **112** can be used to model a variety of well-related performance characteristics. Typically, the program will prompt a user, via output device **78**, for well related parameters that can be used to model one or more aspects of the subject well. The performance modeling program **112** also receives actual data from, for example, sensors such as those illustrated and described with respect to **FIG. 6**. The contrast between the model characteristics and the actual measured data can be presented to a technician through output device **78**. For example, the comparison can be presented graphically, as illustrated in **FIG. 8**.

[**0046**] In the example illustrated in **FIG. 8**, the calculated variable is inlet pressure. The modeling program utilizes the wellhead pressure obtained from a flowing gradient survey and the liquid rate that can also be obtained from the flowing gradient survey. Vertical flow correlations to be checked against the flowing gradient survey are selected using engineering judgment. A gradient **116** is calculated by the performance modeling program **112** and graphically displayed via output device **78**, as illustrated. In this example, gradient **116** is illustrated in graphical form on a graph **118** that plots "pressure" along the x-axis against "elevation" along the y-axis.

[**0047**] The specific gradient **116** can be determined based on a variety of known correlations. For example, a correlation known as the Hagedorn and Brown (HBR) correlation is used to provide the illustrated gradient **116**. A second gradient **120**, based on measured data, also is plotted on graph **118**. Thus, the modeled or calculated gradient can be compared to the actual measured data. In this example, a substantial pressure difference is illustrated between the calculated pressure and the measured pressure, particularly at greater depths. As a result, corrective action can be taken and the measured data re-plotted against the model gradient, as illustrated in **FIG. 9**. Although the appropriate corrective action can vary substantially from one well/application to another, the optimization illustrated in **FIG. 9** resulted from increasing the "hold-up" factor which essentially increased the weight of the hydrostatic column.

[**0048**] As described above, well optimization sometimes can result from simple adjustments to the gas lift system design. However, other modeling results can indicate more substantial redesigns. In either situation, a thorough understanding of the well and the conditions in the well over time can greatly improve the gas lift redesigns. As illustrated in **FIG. 10**, gas lift redesigns can benefit from a variety of factors, such as selecting the best correlations for use in modeling (block **122**), obtaining accurate information related to the completion (block **124**) and the reservoir (block **126**). Other factors can include knowledge of fluid properties (block **128**) and surface parameters (block **130**).

[**0049**] Examples of completion related information that can be useful in gas lift design include type of completion, tubing size, casing size, and any deviations of the well. Well deviation, for example, can affect the inflow and outflow performance of the well and the type of gas lift mandrel suitable for optimum production from such wells. Useful reservoir information may include the type of producing sand, the static bottomhole pressure or reservoir pressure, the static bottomhole temperature, permeability, sand thickness, skin and water leg. Examples of useful fluid properties include viscosity, bubble point pressure, gas-oil-ratio, API gravity data, gas specific gravity, and water salinity. Useful surface information may include separator pressure, flow line considerations, and compressor pressure. Many of these gas lift and environmental factors also can influence the design of modeling programs for modeling a given well or wells.

[**0050**] Along those same lines, the effectiveness of the modeling also greatly influences gas lift redesign and the ability to optimize performance in a given well. It is not only the quality of the data input in a given modeling program but also the correlations used in the model. Some correlations between calculated values and measured data can be more important than others. For example, in redesigning gas lift systems, examples of correlations that can play an important role are illustrated in **FIG. 11** and include bubble point pressure correlations **132**, oil viscosity correlations **134**, and multiphase flow correlations **136**. The redesign may involve a simple setting readjustment, such as adjusting a temperature setting or adjusting the gas injection rate. However, the redesign also may involve more substantial changes to the gas lift system, such as changing components of the gas lift system.

[**0051**] As illustrated in **FIG. 12**, various corrective actions **138** can be taken to optimize production from the subject well based on indications of problem areas from the well modeling. With gas lift systems, the corrective action typically is related to inlet options **140**, outlet options **142**, and downhole options **144**. Determination of potential corrective actions can be performed automatically by processing system **70**, or processing system **70** can be designed to output an indication of deviation between modeled values and measured data, e.g. **FIG. 8**, for review by a technician.

[**0052**] By way of example, high casing pressure or excessive gas usage relative to model values may indicate an inlet problem, such as a choke sized too large. A showing of excessive gas usage can, for example, be indicative of an inlet problem, such as high casing pressure. Other deviations from model parameters can indicate outlet problems, such as valve restrictions, high-back pressure, and improper separator operating pressure. Other deviations can indicate downhole problems, such as a hole in the tubing, a well blowing dry gas, a well that will not take any input gas, valve spacing that is too wide, and other downhole problems. A wide variety of such problems can be corrected to optimize production from the well.

[**0053**] After taking a corrective action or actions, the results may be validated, as illustrated by block **146** in **FIG. 12**. This assessment can be an important part of the redesign, because it serves to check whether production from a given well has been improved and, if so, whether the well production has been fully optimized. In the final optimization, as illustrated by block **148**, the well is operated, and measured data is again compared to the well model to determine the existence of any remaining discrepancies indicating sub-optimal performance. Final well optimization can also involve reviewing data from an entire production network to determine whether changes to a single well has affected the performance of the overall production network.

[**0054**] By way of example, **FIGS. 13-16** illustrate one selected methodology of the present invention for optimizing gas injection rate. Referring to **FIG. 13**, following identification of an underperforming well, a flowing survey of the well is taken (block **1302**). The continuous flow design diagnostics of the present invention, described above, are then applied (block **1304**). As illustrated, the well does (block **1306**) or does not (block **1308**) flow.

[**0055**] Assuming, for example, that the well flows, it will take gas (block **1310**), not take gas (block **1312**), or take gas irregularly (block **1314**). **FIG. 14** illustrates the methodology when the well flows and takes gas (block **1402**). Under these circumstances, injection will either be through a gas lift valve (block **1404**) or not (block **1406**). If injection is through a gas lift valve which is the deepest valve (block **1408**), a reevaluation of the system must be made (block **1410**) to determine whether or not the gas injection rate is optimized (block **1412**).

[**0056**] If the injection is not through the deepest gas lift valve (block **1408**), an evaluation must be made for a deeper point (block **1414**) before checking for mechanical problems (block **1416**). If no mechanical problems are found, the system is redesigned for deeper injection (block **1418**) before reevaluation (block **1410**). If mechanical problems are found, the restriction must be removed (block **1420**) and workover must be considered (block **1422**) before reevaluation (block **1410**).

[**0057**] If injection is not through a gas lift valve (block **1406**), there may either be a hole in the tubing (block **1424**) or a leak in the sidepocket mandrel (block **1426**). In case of a hole in the tubing, a packoff is installed (block **1428**) before the system is reevaluated (block **1410**). In case of a sidepocket mandrel leak, the gas valve is reinstalled (block **1430**) before installation of a packoff (block **1432**) and reevaluation of the system (block **1410**).

[**0058**] **FIG. 15** illustrates the methodology when the well flows but does not take gas (block **1502**). Under these circumstances, there may be a failed gas lift valve (block **1504**), a casing bridge (block **1506**), and excessively high gas lift valve setting (block **1508**), an excessively low gas lift valve design temperature (block **1510**), or a surface gas input problem (block **1512**). The remedial actions are, respectively, to change the gas lift valve (block **1514**), to pump chemical (block **1516**) followed by water (block **1517**), redesign the gas lift valve for a lower pressure (block **1518**), redesign the gas lift valve for a higher temperature (block **1520**), or check for a plugged or frozen choke (block **1522**). In each case, following the specified remedial action the system is reevaluated (block **1524**) to ascertain that the gas injection rate is optimized (block **1526**).

[**0059**] **FIG. 16** illustrates the methodology when the well flows, but gas injection is irregular (block **1602**). Under these circumstances the problem will be either a subsurface problem (block **1604**) or a surface problem (block **1606**). A subsurface problem will manifest itself in either low (block **1608**) or high (block **1610**) casing pressure. When a low casing pressure is evident, there may be a hole in the tubing (block **1612**), the unloading valve may have lost pressure (block **1614**), the valve port fluid may be cut (block **1616**), or the sidepocket mandrel may be leaking (block **1618**). Once the cause of the low casing pressure is ascertained and remedied, the system is reevaluated (block **1620**) to determine if the gas injection rate optimized (block **1622**).

[**0060**] When a high casing pressure is evident, the unloading valve may have gained pressure (block **1624**), the gas lift valve may be operating too deep (block **1626**), or the valve port size may be too small (block **1628**). Upon diagnosing the cause of the high casing pressure and correcting the problem, the system is reevaluated (block **1620**) to determine if the gas injection rate is optimized (block **1622**).

[**0061**] A surface problem (block **1606**) may be reflected in, for example, an unstable gas supply (block **1630**) or an unstable back pressure (block **1632**). Unstable gas supply pressure may be due to an unstable compressor discharge (block **1634**), in which case a redesign for higher (block **1636**) should be undertaken before reevaluation (block **1620**) and optimization of the gas injection rate (block **1622**).

[**0062**] Finally, unstable back pressure (block **1632**) may be due, for example, to an adjacent well heading in a shared manifold (block **1638**) or an unstable separator back pressure (block **1640**) which should be corrected before reevaluation (block **1620**) and optimization of gas injection rate (block **1622**).

[**0063**] Although, only a few embodiments of the present invention have been described in detail above, those of ordinary skill in the art will readily appreciate that many modifications are possible without materially departing from the teachings of this invention. Accordingly, such modifications are intended to be included within the scope of this invention as defined in the claims.

What is claimed is:

1. A method of optimizing production in a well, comprising:

operating a gas lift system in a wellbore;

gathering a plurality of production related parameters;

matching a well model with measured data obtained from the production related parameters to determine discrepancies; and

redesigning the gas lift system based on the discrepancies.

2. The method as recited in claim 1, wherein gathering comprises measuring the gas injection rate.

3. The method as recited in claim 1, wherein gathering comprises measuring the fluid production rate.

4. The method recited in claim 1, wherein gathering comprises obtaining a flowing gradient survey.

5. The method as recited in claim 1, wherein gathering comprises obtaining temperature data.

6. The method as recited in claim 1, wherein gathering comprises obtaining temperature data.

7. The method as recited in claim 6, wherein the temperature data is obtained via a distributed temperature sensing system.

8. The method as recited in claim 1, wherein gathering comprises obtaining surface parameter measurements.

9. The method recited in claim 1, wherein gathering comprises obtaining downhole parameter measurements.

10. The method as recited in claim 1, wherein gathering comprises obtaining episodic measurements.

11. The method as recited in claim 1, wherein gathering comprises measuring a tubing pressure.

12. The method as recited in claim 1, wherein gathering comprises measuring a tubing temperature.

13. The method as recited in claim 1, wherein gathering comprises measuring an injection pressure.

14. The method as recited in claim 1, wherein gathering comprises measuring an injection temperature.

15. The method as recited in claim 1, wherein gathering comprises utilizing a multiphase flow meter.

16. The method as recited in claim 1, wherein gathering comprises measuring a tubing pressure below a gas lift orifice.

17. The method as recited in claim 1, wherein gathering comprises measuring a casing pressure below a gas lift orifice.

18. The method as recited in claim 1, wherein gathering comprises measuring temperature via a slickline deployed distributed temperature sensing system.

19. The method recited in claim 1, further comprising initially selecting a candidate well by obtaining well test data.

20. The method as recited in claim 1, further comprising initially selecting a candidate well by obtaining gas lift monitoring data.

21. The method as recited in claim 1, further comprising initially selecting a candidate well by obtaining well history data.

22. The method as recited in claim 1, further comprising initially selecting a candidate well by obtaining completion specific data.

23. The method as recited in claim 1, further comprising validating any improvements in production following redesign of the gas lift system.

24. The method as recited in claim 1, wherein matching comprises analyzing inflow factors.

25. The method as recited in claim 1, wherein matching comprises analyzing outflow factors.

26. The method as recited in claim 1, wherein matching comprises analyzing surface factors.

27. The method as recited in claim 1, wherein redesigning comprises adjusting a temperature setting.

28. The method as recited in claim 1, wherein redesigning comprises adjusting a gas injection rate.

29. The method as recited in claim 1, wherein redesigning comprises changing a component of the gas lift system.

30. The method as recited in claim 1, wherein redesigning comprises correcting an inlet related limitation.

31. The method as recited in claim 1, wherein redesigning comprises correcting an outlet related limitation.

32. The method as recited in claim 1, wherein redesigning comprises correcting a downhole related limitation.

33. A system for optimizing production in a well, comprising:

a gas lift system positioned in the well;

a sensor system to sense a plurality of well related parameters; and

a well modeling module able to automatically compare a calculated model of the well to measured data based on the plurality of well related parameters to determine factors detrimentally affecting optimization of production from the well.

34. The system as recited in claim 33, wherein the sensor system monitors data in real-time.

35. The system as recited in claim 33, wherein the sensor system comprises a remote processor system.

36. The system as recited in claim 33, wherein the sensor system is configured to sense a quantity of injected gas.

37. The system as recited in claim 33, wherein the sensor system comprises a tubing pressure sensor and tubing temperature sensor.

38. The system as recited in claim 33, wherein the sensor system comprises an injection pressure sensor and an injection temperature sensor.

39. The system as recited in claim 33, further comprising a multiphase flow data sensor.

40. The system as recited in claim 33, further comprising an episodic sensor system.

41. The system as recited in claim 40, wherein the episodic sensor system is configured to obtain a flowing gradient survey.

42. The system as recited in claim 40, wherein the episodic sensor system is configured to obtain a distributed temperature profile.

43. A method of optimizing production from a gas lift system disposed in a well, comprising:

flowing a gas through the gas lift system;

obtaining measured data from a plurality of sensors positioned to sense production related parameters;

graphically plotting a gradient based on the measured data;

graphically plotting a model gradient; and

comparing the gradient and the model gradient to determine whether production can be optimized.

44. The method as recited in claim 43, further comprising optimizing production performance of the gas lift system.

45. The method as recited in claim 44, further comprising adjusting the gas lift system to optimize performance.

46. The method as recited in claim 45, wherein adjusting comprises correcting an inlet related limitation on production.

47. The method as recited in claim 45, wherein adjusting comprises correcting an outlet related limitation on production.

48. The method as recited in claim 45, wherein adjusting comprises correcting a downhole related limitation on production.

49. The method as recited in claim 45, wherein adjusting comprises adjusting a temperature setting.

50. The method as recited in claim 45, wherein adjusting comprises adjusting a gas injection rate.

51. The method as recited in claim 45, wherein adjusting comprises changing a component of the gas lift system.

52. The method as recited in claim 45, wherein adjusting comprises adjusting a choke size.

53. The method as recited in claim 45, wherein adjusting comprises adjusting a casing pressure.

54. The method as recited in claim 45, wherein adjusting comprises adjusting a separator operating pressure.

55. The method as recited in claim 45, wherein adjusting comprises removing a valve restriction.

56. The method as recited in claim 45, wherein adjusting comprises fixing a tubing hole.

57. The method as recited in claim 45, wherein adjusting comprises changing a valve spacing.

* * * * *