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(71) Applicant(s)
Halliburton Energy Services, Inc.

(72) Inventor(s)
Bakri, Emad; Lovorn, James R.; Lewis, Derrick W.

(74) Agent / Attorney
Pizzseys, PO Box 291, WODEN, ACT, 2606

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(71) Applicant (for all designated States except US): HAL-

LIBURTON ENERGY SERVICES, INC. [US/US];
10200 Bellaire Boulevard, Houston, TX 77072 (US).

(72) Inventors; and

(75) Inventors/Applicants (for US only): BAKRI, Emad
[EG/US]; 3000 North Sam Houston Parkway East, Hous-
ton, TX 77032 (US). LOVORN, James, R. [US/US];
3000 North Sam Houston Parkway East, Houston, TX
77032 (US). LEWIS, Derrick, W. [US/US]; 3000 North
Sam Houston Parkway East, Houston, TX 77032 (US).(74) Agent: SMITH, Marlin, R.; SMITH IP SERVICES, P.C.,
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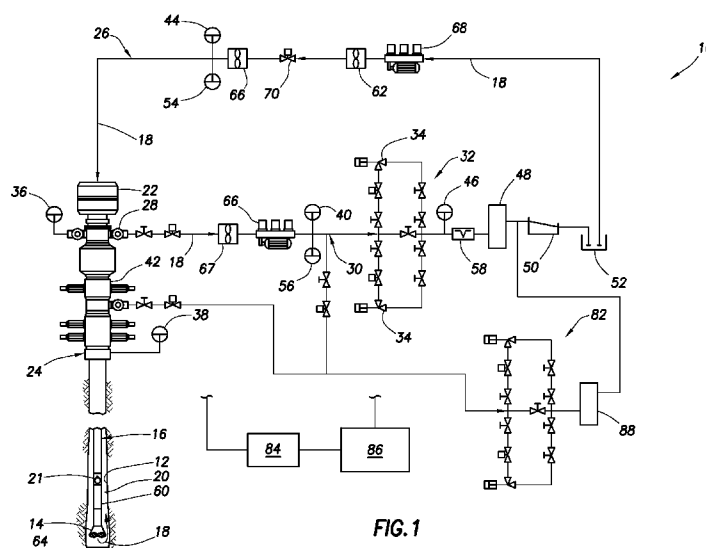


FIG. 1

(57) Abstract: A well pressure control method can include regulating pressure in a wellbore by operating a suction pump which draws fluid from an annulus formed between a drill string and the wellbore, the fluid entering the suction pump proximate the earth's surface. Another well pressure control method can include regulating pressure in a wellbore by operating a suction pump which applies suction pressure to an annulus formed between a drill string and the wellbore. A well drilling system can include a suction pump positioned proximate the earth's surface. The suction pump can receive fluid which exits an annulus formed between a drill string and a wellbore.

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**WELL DRILLING SYSTEMS AND METHODS
WITH PUMP DRAWING FLUID FROM ANNULUS**

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TECHNICAL FIELD

This disclosure relates generally to equipment utilized and operations performed in conjunction with well drilling and, in one example described below, more particularly provides well drilling systems and methods with a pump drawing fluid from an annulus.

BACKGROUND

Control of pressure in a wellbore is of utmost importance, particularly during drilling operations. Well pressure control systems generally should prevent undesired loss of drilling fluid to a formation penetrated by a wellbore (although in some drilling operations a certain amount of fluid loss can be desirable), and generally should prevent undesired influx of formation fluid from the formation into the wellbore (although in some drilling operations a controlled influx of fluid into the wellbore can be desirable). Therefore, it will be appreciated that advancements are continually needed in the art of well pressure control.

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BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a representative view of a well drilling system which can embody principles of this disclosure.

5 FIG. 2 is a representative flowchart representing a method which can embody principles of this disclosure.

FIG. 3 is a representative flowchart of a parameter signature generation process which may be used in the method of FIG. 2.

10 FIG. 4 is a representative flowchart of an event signature generation and event identification process which may be used in the method of FIG. 2.

FIG. 5 is a representative listing of events and corresponding event signatures which may be used in the
15 method of FIG. 2.

FIG. 6 is a representative elevational view of a vacuum pump which may be used in the well drilling system.

FIG. 7 is a representative elevational view of another configuration of the system incorporating the vacuum pump.

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DETAILED DESCRIPTION

Representatively illustrated in FIG. 1 is a well drilling system 10 and associated method which can incorporate principles of this disclosure. In the system 10,
25 a wellbore 12 is drilled by rotating a drill bit 14 on an end of a drill string 16. Drilling fluid 18 (commonly known as "mud," although brine or other types of fluids may be used) is circulated downward through the drill string 16, out the drill bit 14 and upward through an annulus 20 formed
30 between the drill string and the wellbore 12, in order to

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cool the drill bit, lubricate the drill string, remove cuttings and provide a measure of bottom hole pressure control. A non-return valve 21 (typically a flapper-type check valve) prevents flow of the drilling fluid 18 upward
5 through the drill string 16 (e.g., when connections are being made in the drill string).

Control of pressure in the wellbore 12 is very important in managed pressure drilling, and in other types of drilling operations. Preferably, the well pressure is
10 accurately controlled to prevent excessive loss of fluid into an earth formation 64 surrounding the wellbore 12, undesired fracturing of the formation, undesired influx of formation fluids into the wellbore, etc. In typical managed pressure drilling, it is desired to maintain the pressure in
15 the wellbore 12 just greater than a pore pressure of the formation penetrated by the wellbore, without exceeding a fracture pressure of the formation. In typical underbalanced drilling, it is desired to maintain the wellbore pressure somewhat less than the pore pressure, thereby obtaining a
20 controlled influx of fluid from the formation.

Nitrogen or another gas, or another lighter weight fluid, may be added to the drilling fluid 18 for pressure control. This technique is useful, for example, in underbalanced drilling operations.

25 In the system 10, additional control over the well pressure is obtained by closing off the annulus 20 (e.g., isolating it from communication with the atmosphere and enabling a pressure differential to be maintained between the annulus and the atmosphere at or near the surface), for
30 example, using a rotating control device 22 (RCD). The RCD 22 seals about the drill string 16 above a wellhead 24, and can do so while the drill string rotates therein. In other

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examples, the drill string 16 may be isolated from the atmosphere using a sealing device, without the drill string rotating within the sealing device (e.g., when drilling with a downhole drilling motor, when drilling with coiled tubing, etc.).

Although not shown in FIG. 1 (see FIG. 7), the drill string 16 can extend upwardly through the RCD 22 for connection to, for example, a rotary table (not shown), a standpipe line 26, a kelley (not shown), a top drive (not shown) and/or other conventional drilling equipment. However, use of the RCD 22 is not necessary in keeping with the principles of this disclosure.

In the FIG. 1 example, the drilling fluid 18 exits the wellhead 24 via a wing valve 28 in communication with the annulus 20 below the RCD 22. The fluid 18 then flows through drilling fluid return line 30 to a choke manifold 32, which preferably includes redundant chokes 34 (only one of which may be used at a time). Backpressure can be applied to the annulus 20 by variably restricting flow of the fluid 18 through the operative choke(s) 34.

The greater the restriction to flow through the choke 34, the greater the backpressure applied to the annulus 20. Thus, pressure in the wellbore 12 can be conveniently regulated by varying the backpressure applied to the annulus 20. A hydraulics model can be used to determine a pressure in the annulus 20 at or near the earth's surface which will result in a desired wellbore pressure, so that an operator (or an automated control system) can readily determine how to regulate the pressure applied to the annulus at or near the surface (which can be conveniently measured) in order to obtain the desired wellbore pressure.

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Pressure in the annulus 20 can be measured at or near the surface via a variety of pressure sensors 36, 38, 40, each of which is in communication with the annulus. Pressure sensor 36 senses pressure below the RCD 22, but above a
5 blowout preventer (BOP) stack 42. Pressure sensor 38 senses pressure in the wellhead 24 below the BOP stack 42. Pressure sensor 40 senses pressure in the drilling fluid return line 30 upstream of the choke manifold 32.

Another pressure sensor 44 senses pressure in the
10 drilling fluid injection (standpipe) line 26. Yet another pressure sensor 46 senses pressure downstream of the choke manifold 32, but upstream of a separator 48, shaker 50 and mud pit 52. Additional sensors include temperature sensors 54, 56, Coriolis flowmeter 58, and flowmeters 62, 67.

15 The flowmeter 62 measures a flow rate of the fluid 18 being injected into the drill string 16 by a rig mud pump 68. The flow meter 67 measures a flow rate of the fluid 18 upstream of a suction pump 66 used to draw the fluid from the annulus 20.

20 Not all of these sensors are necessary. However, input from additional sensors is useful to the hydraulics model in determining what the pressure in the annulus 20 should be during the drilling operation.

Furthermore, the drill string 16 may include its own
25 sensors 60, for example, to directly measure well pressure. Such sensors 60 may be of the type known to those skilled in the art as pressure while drilling (PWD), measurement while drilling (MWD) and/or logging while drilling (LWD) systems. These drill string sensor systems generally provide at least
30 pressure measurement, and may also provide temperature measurement, detection of drill string characteristics (such as vibration, torque, rpm, weight on bit, stick-slip, etc.),

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formation characteristics (such as resistivity, density, etc.), fluid characteristics and/or other measurements.

Various forms of telemetry (acoustic, pressure pulse, pressure level, electromagnetic, etc.) may be used to
5 transmit the downhole sensor 60 measurements to the surface. The downhole sensors 60 may be used in combination with, or instead of, the surface sensors to, for example, periodically calibrate the hydraulics model, to more directly control operation of the system 10, etc.

10 Additional sensors could be included in the system 10, if desired. Pressure and level sensors could be used with the separator 48, level sensors could be used to indicate a volume of drilling fluid in the mud pit 52, etc.

Fewer sensors could be included in the system 10, if
15 desired. For example, the output of the rig mud pump 68 could be determined by counting pump strokes, instead of by using flowmeter 62 or any other flowmeters. Thus, it should be understood that it is not necessary for the system 10 to include all of the sensors depicted in FIG. 1 and described
20 herein, and the system could instead include additional sensors, different combinations and/or types of sensors, etc.

Note that the separator 48 could be a 3 or 4 phase separator, or a mud gas separator (sometimes referred to as
25 a "poor boy degasser"). However, the separator 48 is not necessarily used in the system 10.

The drilling fluid 18 is pumped through the standpipe 26 and into the interior of the drill string 16 by the rig mud pump 68. The pump 68 receives the fluid 18 from the mud
30 pit 52 and flows it via a standpipe manifold (represented by valve 70 in FIG. 1) to the standpipe 26, the fluid then circulates downward through the drill string 16, upward

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through the annulus 20, through the pump 66, through the drilling fluid return line 30, through the choke manifold 32, and then via the separator 48 and shaker 50 to the mud pit 52 for conditioning and recirculation.

5 Note that, in the system 10 as so far described above, the choke 34 cannot be used to control backpressure applied to the annulus 20 for control of the well pressure, unless the fluid 18 is flowing through the choke. In conventional overbalanced drilling operations, such a situation can arise
10 whenever a connection is made in the drill string 16 (e.g., to add another length of drill pipe to the drill string as the wellbore 12 is drilled deeper), and the lack of circulation will require that well pressure be regulated solely by the density of the fluid 18.

15 In the system 10, however, pressure in the well can be conveniently regulated by use of the suction pump 66 instead of, or in combination with, use of the choke 34 for such purpose. Even if the density of the fluid 18 is such that the well is statically overbalanced (that is, pressure in
20 the wellbore 12 is greater than the pore pressure of the formation 64 penetrated by the wellbore, with substantially no circulation of the fluid), the pump 66 can draw fluid down in the annulus 20 to reduce the hydrostatic pressure of the fluid in the wellbore, and/or the pump can directly
25 reduce the pressure in the annulus if the annulus is sealed from atmosphere (e.g., with the RCD 22).

 Whether or not the fluid 18 is being injected through the drill string 16 by the rig mud pump 68, the pump 66 can be used to regulate pressure in the annulus 20, so that
30 pressure in the wellbore 12 is selectively over, under, or at balance with the pore pressure of the formation 64 penetrated by the wellbore. Of course, pressure in the

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wellbore 12 at other locations (such as, at a casing shoe, an under-pressurized zone, etc.) can similarly be regulated by use of the pump 66.

5 In a typical mode of operation, the fluid 18 density is chosen so that pressure in the wellbore 12 will be somewhat statically overbalanced with respect to pressure in the formation 64 (e.g., the hydrostatic pressure due to the weight of the vertical column of fluid is greater than formation pressure). The suction pump 66 is used to decrease
10 the pressure in the wellbore 12 as desired, so that pressure in the wellbore is at a desired level (e.g., at balance, slightly overbalanced, somewhat underbalanced, etc.) while the fluid 18 is circulating through the drill string 16 and wellbore, while the fluid is not circulating, while the
15 wellbore is being drilled, while connections are being made in the drill string, etc.

In this manner, safety is enhanced because the density of the fluid 18 acts as a barrier to prevent inadvertent escape of well fluids from the well (due to, for example,
20 influx of formation fluids into the wellbore 12 from the formation 64, etc.). Coupled with the BOP stack 42, this provides multiple barriers to inadvertent escape of well fluids.

Note that, in other examples, the system 10 could
25 include a backpressure pump (not shown) for applying pressure to the annulus 20 and drilling fluid return line 30 upstream of the choke manifold 32, if desired. The backpressure pump could be used, for example, to ensure that fluid 18 continues to flow through the choke manifold 32
30 during events such as making connections in the drill string 16. In that case, additional sensors may be used to, for

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example, monitor the pressure and flow rate output of the backpressure pump.

The use of a backpressure pump is described in International Application No. PCT/US10/38586, filed 15 June 5 2010. That international application also describes a method of correcting an annulus pressure setpoint during drilling.

In other examples, connections may not be made in the drill string 16 during drilling, for example, if the drill string comprises a continuous coiled tubing. The drill 10 string 16 could be provided with conductors and/or other lines (e.g., in a sidewall or interior of the drill string) for transmitting data, commands, pressure, etc., between downhole and the surface (e.g., for communication with the sensors 60).

15 Methods of controlling pressure and flow in drilling operations, including the use of data validation and a predictive device, are described in International Application No. PCT/US10/56433, filed 12 November 2010. Such methods could be used in the system 10.

20 Following is a description of an event detection method which can be used with the system 10 (including the suction pump 66). However, it should be clearly understood that use of the event detection method is not necessary in keeping with the scope of this disclosure, and other event detection 25 methods could be used instead, if desired.

EVENT DETECTION

Referring additionally now to FIG. 2, a well drilling method 90 which may be used with the system 10 of FIG. 1 is 30 representatively illustrated in flowchart form. However, it should be clearly understood that the method 90 could be

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used in conjunction with other systems in keeping with the scope of this disclosure.

The method 90 includes an event detection process which can be used to alert an operator if an event occurs, such as, by triggering an alarm or displaying a warning if the event is an undesired event (e.g., unacceptable fluid loss to the formation 64, unacceptable fluid influx from the formation into the wellbore 12, etc.), or by displaying information about the event if it is a normal, expected or desired event, etc. Well drilling methods incorporating event detection are described in International Application No. PCT/US09/52227, filed 30 July 2009.

An event can be a precursor to another event happening, in which case detection of the first event can be used as an indication that the second event is about to happen or is in process of occurring. In addition, a series of events can also provide an indication that another event is about to happen. Thus, one or more prior events can be used as a source of data for determining if another event will occur.

Many different events and types of events can be detected in the method 90. These events can include, but are not limited to, a kick (influx), partial fluid loss, total fluid loss, standpipe bleed down, plugged choke 34, washed out choke, poor hole cleaning (wellbore 12 packed off about drill string 16), downhole crossflow, wellbore washout, under gauged wellbore, drilling break, ballooning while circulating, ballooning while mud pump is off, stuck pipe, twisted off pipe, back off, plugging of bit nozzle, bit nozzle washed out, leak in surface processing equipment, rig pump 68 failure, suction pump 66 failure, downhole sensor 60 failure, washed out drill string, non-return valve

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21 failure, start of drill pipe connection, drill pipe connection finished, etc.

In order to detect the events, drilling parameter "signatures" produced in real time are compared to a set of event "signatures" in order to determine if any of the events represented by those event signatures is occurring. Thus, what is happening currently in the drilling operation (the drilling parameter signatures) is compared to a set of signatures which correspond to drilling events and, if there is a match, this is an indication that the event corresponding to the matched event signature is occurring.

Drilling properties (e.g., pressure temperature, flow rate, etc.) are sensed by sensors, and output from the sensors is used to supply data indicative of the drilling properties. This drilling property data is used to determine drilling parameters of interest.

Data can also be in the form of information relating to offset wells (e.g., other wells drilled nearby or in similar lithologies, conditions, etc.). Previous experience of drillers can also serve as a source for the data. Data can also be entered by an operator prior to or during the drilling operation.

A drilling parameter can comprise data related to a single drilling property, or a parameter can comprise a ratio, product, difference, sum or other function of data related to multiple drilling properties. For example, it is useful in drilling operations to monitor the difference between the flow rate of drilling fluid injected into the well (e.g., via the standpipe line 26 as sensed by flowmeter 62) and the flow rate of drilling fluid returned from the well (e.g., via the drilling fluid return line 30 as sensed by the flowmeter 67). Thus, a parameter of interest, which

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can be used to define a part or segment of a signature can be this difference in drilling properties (e.g., flow rate in minus flow rate out).

During a drilling operation, the drilling properties
5 are sensed over time, either continuously or intermittently. Thus, data related to the drilling properties is available over time, and the behavior of each drilling parameter can be evaluated in real time. Of particular (but not exclusive)
10 interest in the method 90 is how the drilling parameters change over time, that is, whether each parameter is increasing, decreasing, remaining substantially the same, remaining within a certain range, exceeding a maximum, falling below a minimum, etc.

These parameter behaviors are given appropriate values,
15 and the values are combined to generate parameter signatures indicative of what is occurring in real time during the drilling operation. For example, one segment of a parameter signature could indicate that standpipe pressure (e.g., as measured by sensor 44) is increasing, and another segment of
20 the parameter signature could indicate that pressure upstream of the choke manifold (e.g., as measured by sensor 40) is decreasing.

A parameter signature can include many (perhaps 20 or more) of these segments. Thus, a parameter signature can
25 provide a "snapshot" of what is happening in real time during the drilling operation.

An event signature, on the other hand, does not represent what is occurring in real time during a drilling operation. Instead, an event signature is representative of
30 what the drilling parameter behaviors will be when the corresponding event does happen. Each event signature is

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preferably distinctive, because each event is indicated by a distinctive combination of parameter behaviors.

As discussed above, an event can be a precursor to another event. In that case, the event signature for the
5 first event can be a distinctive combination of parameter behaviors which indicate that the second event is about to (or at least is eventually going to) happen.

Events can be parameters, for example, in the circumstance discussed above in which a series of events can
10 indicate that another event is going to happen. In that case, the corresponding parameter behavior can be whether or not the precursor event(s) have happened.

Event signatures can be generated prior to commencing a drilling operation, and can be based on experience gained
15 from drilling similar wells under similar conditions, etc. Event signatures can also be refined as a drilling operation progresses and more experience is gained on the well being drilled.

In basic terms, sensors are used to sense drilling
20 properties during a drilling operation, data relating to the sensed properties are used to determine drilling parameters of interest, values indicative of the behaviors of these parameters are combined to form parameter signatures, and the parameter signatures are compared to pre-defined event
25 signatures to detect whether any of the corresponding events is occurring, or is substantially likely to occur.

Representative steps in the event detection process are depicted in FIG. 2 in flowchart form. However, it should be understood that the method 90 can include additional,
30 alternative or optional steps as well, and it is not necessary for all of the depicted steps to be performed in keeping with the principles of this disclosure.

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In a first step 92 depicted in FIG. 2, data is received. The data in this example can be received from a central database, such as an INSITE™ database marketed by Halliburton Energy Services, Inc. of Houston, Texas USA, although other databases may be used if desired.

The data typically is in the form of measurements of drilling properties as sensed by various sensors during a drilling operation. For example, the sensors 36, 38, 40, 44, 46, 54, 56, 58, 60, 62, 67 (or another combination of sensors) will produce indications of various properties (such as pressure, temperature, mass and/or volumetric flow rate, density, resistivity, rpm, torque, weight, position, etc.), which will be stored as data in the database. Calibration, conversion and/or other operations may be performed for the data prior to the data being received from the database.

The data may also be entered manually by an operator. As another alternative, data can be received directly from one or more sensors, or from another data acquisition system, whether or not the data originates from sensor measurements, and without first being stored in a separate database. Furthermore, as discussed above, the data can be derived from an offset well, previous experience, etc. Any source for the data may be used, in keeping with the principles of this disclosure.

In step 94, various parameter values are calculated for later use in the method 90. For example, it may be desirable to calculate a ratio of data values, a sum of data values, a difference between data values, a product of data values, etc. In some instances, however, the value of the data itself is used as is, without any further calculation.

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In step 96, the parameter values are validated and smoothing techniques may be used to ensure that meaningful parameter values are utilized in the later steps of the method 90. For example, a parameter value may be excluded if
5 it represents an unreasonably high or low value for that parameter, and the smoothing techniques may be used to prevent unacceptably large parameter value transitions from distorting later analysis. A parameter value can correspond to whether or not another event has occurred, as discussed
10 above.

In step 98, the parameter signature segments are determined. This step can include calculating values indicative of the behaviors of the parameters. For example, if a parameter has an increasing trend, a value of 1 may be
15 assigned to the corresponding parameter signature segment; if a parameter has a decreasing trend, a value of 2 may be assigned to the segment; if the parameter is unchanged, a value of 0 may be assigned to the segment, etc. To determine the behavior of a parameter, statistical calculations
20 (algorithms) may be applied to the parameter values resulting from step 96.

Comparisons between parameters may also be made to determine a particular signature segment. For example, if one parameter is greater than another parameter, a value of
25 1 may be assigned to the signature segment, if the first parameter is less than the second parameter, a value of 2 may be assigned, if the parameters are substantially equal, a value of 0 may be assigned, etc.

In step 100, the parameter signature segments are
30 combined to make up the parameter signatures. Each parameter signature is a combination of parameter signature segments

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and represents what is happening in real time in the drilling operation.

In step 102, the parameter signatures are compared to the previously defined event signatures to see if there is a match. Since data is continuously (or at least
5 intermittently) being generated in real time during a drilling operation, corresponding parameter signatures can also be generated in the method 90 in real time for comparison to the event signatures. Thus, an operator can be
10 informed immediately during the drilling operation whether an event is occurring.

Step 104 represents defining of the event signatures which, as described above, can be performed prior to and/or during the drilling operation. Example event signatures are
15 provided in FIG. 5, and are discussed in further detail below.

In step 106, an event is indicated if there is a match between an event signature and a parameter signature. An indication can be provided to an operator, for example, by
20 displaying on a computer screen information relating to the event, displaying an alert, sounding an alarm, etc. Indications can also take the form of recording the occurrence of the event in a database, computer memory, etc. A control system can also, or alternatively, respond to an
25 indication of an event, as described more fully below.

In step 108, a probability of an event occurring is indicated if there is a partial match between an event signature and a parameter signature. For example, if an event signature comprises a combination of 30 parameter
30 behaviors, and a parameter signature is generated in which 28 or 29 of the parameter behaviors match those of the event signature, there may be a high probability that the event is

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occurring, even though there may not be a complete match between the parameter signature and the event signature. It could be useful to provide an indication or alarm to an operator in this circumstance that the probability that the event is occurring is high.

Another useful indication would be of the probability of the event occurring in the future. For example if, as in the example discussed above, a substantial majority of the parameter behaviors match between the parameter signature and the event signature, and the unmatched parameter behaviors are trending toward matching, then it would be useful (particularly if the event is an undesired event) to warn an operator that the event is likely to occur, so that remedial measures may be taken if needed (for example, to prevent the undesired event from occurring).

Referring additionally now to FIG. 3, a flowchart of another example of the process of generating the parameter signatures in the method 90 is representatively illustrated. The process begins with receiving the data as in step 92 described above. Parameter value calculations are then performed as in step 94 described above.

In step 110, preprocessing operations are performed for the parameter values. For example, maximum and minimum limits may be used for particular parameters, in order to exclude erroneously high or low values of the parameters.

In step 112, the preprocessed parameter values are stored in a data buffer. The data buffer is used to queue up the parameter values for subsequent processing.

In step 114, conditioning calculations are performed for the parameter values. For example, smoothing may be used (such as, moving window average, Savitzky-Golay smoothing, etc.) as discussed above in relation to step 96.

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In step 116, the conditioned parameter values are stored in a data buffer.

In step 118, statistical calculations are performed for the parameter values. For example, trend analysis (such as, 5 straight line fit, determination of trend direction over time, first and second order derivatives, etc.) may be used to characterize the behavior of a parameter. Values assigned to the parameter behaviors can become segments of the resulting parameter signatures, as discussed above for step 10 98.

In step 120, the parameter signature segments are output to the database for storage, subsequent analysis, etc. In this example, the parameter signature segments become part of the INSITE™ database for the drilling 15 operation.

In step 100, as discussed above, the parameter signature segments are combined to form the parameter signatures.

Referring additionally now to FIG. 4, a flowchart of a 20 process for identifying that an event has occurred, or will occur, in the method 90 is representatively illustrated. The process begins with step 122, in which an event signature database is configured. The database can be configured to include any number of event signatures to enable any number 25 of corresponding events to be identified during a drilling operation. Preferably, the event signature database can be separately configured for different types of drilling operations, such as underbalanced drilling, overbalanced drilling, at balance drilling, managed pressure drilling, 30 drilling in particular lithologies, etc.

In step 124, a desired set of event signatures are loaded into the event signature database. As discussed

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above, any number, type and/or combination of event signatures may be used in the method 90.

In step 126, the event signature database is queried to see if there are any matches to the parameter signatures
5 generated in step 100. As discussed above, partial matches may optionally be identified, as well.

In step 128, events are identified which correspond to event signatures that match (or at least partially match) any parameter signatures. The output in step 130 can take
10 various different forms, which may depend upon the identified event. An alarm, alert, warning, display of information, etc. may be provided as discussed above for step 106. At a minimum, occurrence of the event should be recorded, and in this example preferably is recorded, as
15 part of the INSITE™ database for the drilling operation.

Referring additionally now to FIG. 5, two example event signatures are representatively tabulated, along with parameter behaviors which correspond to the segments of the signatures. In practice, many more event signatures may be
20 provided, and more or less parameter behaviors may be used for determining the signature segments.

Note that each event signature is distinctive. Thus, a kick (influx) event is indicated by a particular combination of parameter behaviors, whereas a fluid loss event is
25 indicated by another particular combination of parameter behaviors.

If, during a drilling operation, a parameter signature is generated which matches (or at least partially matches) either of the event signatures shown in FIG. 5, an
30 indication can be provided that the corresponding event is occurring. If a parameter signature is generated which matches an event signature to a predetermined level, or if

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the parameter signature's segments are trending toward matching, then an indication may be provided that the corresponding event is substantially likely to occur. This can happen even without any human intervention, resulting in
5 a more automated, precise and safe drilling operation.

The event indications provided by the method 90 can also be used to control the drilling operation. For example, if an undesired kick event is indicated, the suction pump 66 and/or the operative choke(s) 34 can be adjusted in response
10 to increase pressure in the annulus 20. If an undesired loss of fluid 18 is detected, the suction pump 66 and/or choke(s) 34 can be adjusted to decrease pressure in the annulus 20.

These and other types of control over the drilling operation can be implemented based on detection of the
15 corresponding events using the method 90 automatically and without human intervention, if desired. In one example, a control system such as that described in International Application No. PCT/US08/87686 may be used for implementing the control over the drilling operation.

20 In some embodiments, human intervention could be used, for example, to determine whether the control over the drilling operation should be implemented in response to detection of events in the method 90. Thus, if an event is detected (or if the event is indicated as being likely to
25 happen), a human's authorization may be required before the drilling operation is automatically controlled in response.

As depicted in FIG. 1, a controller 84 (such as a programmable logic controller or another type of controller capable of controlling operation of drilling equipment) is
30 connected to a control system 86 (such as, the control system described in International Application No. PCT/US08/87686, or the control system described in

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International Application No. PCT/US10/56433). The controller 84 is also connected to flow control devices (such as chokes 34, etc.) for regulating flow injected into the drill string 16, flow through the drilling fluid return
5 line 30, etc.

The control system 86 can include various elements, such as one or more computing devices/processors, a hydraulics model, a wellbore model, a database, software in various formats, memory, machine-readable code, etc. These
10 elements and others may be included in a single structure or location, or they may be distributed among multiple structures or locations, local or remote from the drilling operation.

The control system 86 is operatively connected to the
15 sensors 36, 38, 40, 44, 46, 54, 56, 58, 60, 62, 67, which sense respective drilling properties during the drilling operation. As discussed above, offset well data, previous operator experience, other operator input, etc., may also be input to the control system 86. The control system 86 can
20 include software, programmable and preprogrammed memory, machine-readable code, etc., for carrying out the steps of the method 90 described above.

The control system 86 may be located at the wellsite, in which case the sensors 36, 38, 40, 44, 46, 54, 56, 58,
25 60, 62, 67 could be connected to the control system by wires or wirelessly. Alternatively, the control system 86 could be positioned at a remote location, in which case the control system could receive data via satellite transmission, the Internet, wirelessly, or by any other appropriate means. The
30 controller 84 can also be connected to the control system 86 in various ways, whether the control system is locally or remotely located.

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In one example, the control system 86 can cause the suction pump 66 to increase pressure in the annulus 20 at or near the surface by a predetermined amount automatically in response to the step 130 output indicating that a kick (influx) has occurred, or is substantially likely to occur. For example, if the parameter signature matches (or substantially matches) the event signature for a kick, then the control system 86 will operate the controller 84 to cause the pump 66 to increase pressure in the annulus 20 by the predetermined amount (e.g., a percentage of the current annulus pressure, a particular difference in pressure, etc.).

The predetermined amount could be preprogrammed into the control system 86, and/or the predetermined amount could be input, for example, via a human-machine interface. After the pressure in the annulus 20 has increased by the predetermined amount, control over operation of the suction pump 66 can be returned to an automated system whereby an annulus, wellbore or standpipe pressure set point is maintained (which set point may be obtained, e.g., from a hydraulics model or manual input), the suction pump can be manually operated, or another manner of controlling the pump can be implemented.

In another example, the control system 86 can cause the suction pump 66 to decrease pressure in the annulus 20 by a predetermined amount automatically in response to the step 130 output indicating that a fluid loss has occurred, or is substantially likely to occur. For example, if the parameter signature matches (or substantially matches) the event signature for a fluid loss, then the control system 86 will operate the controller 84 to cause the suction pump 66 to decrease pressure in the annulus 20 by the predetermined

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amount (e.g., a percentage of the current annulus pressure, a particular difference in pressure, etc.).

The predetermined amount could be preprogrammed into the control system 86, and/or the predetermined amount could
5 be input, for example, via a human-machine interface. After the annulus 20 pressure has been decreased by the predetermined amount, control over operation of the pump 66 can be returned to the automated system whereby an annulus, wellbore or standpipe pressure set point is maintained
10 (which set point may be obtained, e.g., from a hydraulics model or manual input, etc.), the pump can be manually operated, or another manner of controlling the pump can be implemented.

In another example, the control system 86 can provide
15 an alert or an alarm to an operator that a particular event has occurred or is substantially likely to occur, the probability of the event occurring, etc. The operator can then take any needed remedial actions based on the alert/alarm, or can override any actions taken by the
20 control system 86 automatically in response to the step 130 output. If action has already been taken by the control system 86, the operator can undo or reverse such actions, if desired.

In another example, the control system 86 can switch
25 between maintaining a desired annulus or wellbore pressure to maintaining a desired standpipe pressure in response to the step 130 output indicating that an event has occurred, or is substantially likely to occur. The suction pump 66 can be automatically controlled to thereby maintain any annulus,
30 wellbore and/or standpipe pressure set point.

Techniques by which a control system can maintain a wellbore pressure are described in International Application

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Nos. PCT/US10/38586 and PCT/US10/56433, and a technique by which a control system can maintain a standpipe pressure is described in International Application No. PCT/US11/31767. Similar techniques can be applied to control operation of
5 the suction pump 66, in order to automatically control pressure in the annulus 20, pressure at various locations in the wellbore 12, and/or pressure in the standpipe 26.

The control system 86 can switch between such annulus, wellbore and standpipe pressure set point modes
10 automatically in response to the step 130 output indicating that an event has occurred, or is substantially likely to occur. For example, if a kick (influx) event is detected, the control system 86 could switch from maintaining a desired wellbore pressure to maintaining a desired standpipe
15 pressure. This switch may actually be performed after verifying that conditions are acceptable for making the switch, and after providing an operator with an option (such as, via a displayed alert) to initiate or override the switch, etc.

20 In another example, the control system 86 can automatically provide an operator (such as a driller) with instructions or guidance for what remedial measures to take in response to the step 130 output indicating that an event has occurred or is substantially likely to occur. The
25 instructions or guidance may be provided by a local well site display, and/or may be transmitted between the well site and a remote location, etc.

In another example, the control system 86 can implement a well control procedure automatically in response to the
30 step 130 output indicating that an event has occurred, or is substantially likely to occur. The well control procedure could include routing return flow of the fluid 18 to a

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conventional rig choke manifold 82 and gas buster 88 (see FIG. 1) designed for handling well control situations.

Alternatively, the well control procedure could include the control system 86 automatically operating the pump 66
5 and/or choke 34 to optimally circulate out an undesired influx. An example of automated operation of a choke manifold to circulate out an undesired influx is described in International Application No. PCT/US10/20122, filed 5
January 2010. Similar techniques can be used to
10 automatically operate the pump 66 to optimally circulate out the undesired influx (e.g., maintaining optimal pressure in the annulus 20 and wellbore 12 over time, while the undesired influx flows to the surface through the annulus).

In another example, the control system 86 can switch
15 flow of the fluid 18 from one suction pump 66 to another automatically, in response to the step 130 output indicating that one of the pumps has become inoperative or otherwise compromised, or is substantially likely to become so
compromised. The switching from one pump 66 to another can
20 be performed progressively and automatically, so that a desired annulus, wellbore and/or standpipe pressure can concurrently be maintained by the control system 86 during the switching process.

In another example, the control system 86 can modify or
25 correct a pressure set point (e.g., received from a hydraulics model) automatically in response to the step 130 output indicating that: a) a sensor (such as the sensor 60, a pressure while drilling (PWD) tool, etc.) has failed or is substantially likely to fail, b) the drill string 16 has
30 parted (e.g., twisted off, disconnected, backed off, etc.) downhole or is substantially likely to do so, and/or c) an influx or loss event has occurred or is substantially likely

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to occur, making adjustment of fluid 18 density in the wellbore 12 desirable in models, such as the hydraulics model and/or a well model. The control system 86 can operate the controller 84 using the modified/corrected set point, instead of the set point received from, e.g., the hydraulics model. The control system 86 can update the hydraulics and/or well model(s) with updated fluid 18 density values based on the detection of the fluid influx or loss event.

In another example, the control system 86 can automatically communicate to the hydraulics and/or well model(s) that an event has been detected. For example, if the event is a failure of the sensor 60 (such as a PWD sensor, etc.), the control system 86 can automatically communicate this to the hydraulics model, which will cease correcting the pressure set point based on actual measurements from that sensor. As another example, if the event is parting of the drill string 16, the control system 86 can automatically communicate this to the hydraulics and/or well model(s), which will adjust a volume of the annulus 20 and/or other parameters in the model(s).

In another example, the control system 86 can cause the suction pump 66 to decrease pressure in the annulus 20 automatically in response to the step 130 output indicating that excessive pressure exists in the wellbore 12 (or at least upstream of the pump). A maximum pressure can be preprogrammed into the control system 86 so that, if the maximum pressure is exceeded, the suction pump 66 and/or choke 34 will be operated by the controller 84 to relieve the excess pressure.

In another example, the control system 86 can divert flow to a rig choke manifold 82, or to another choke manifold similar to the choke manifold 32, automatically in

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response to the step 130 output indicating that a sealing element of the RCD 22 has failed, or is substantially likely to fail. The control system 86 could also automatically operate the pump 66 and/or choke 34, to thereby relieve
5 pressure under the RCD 22.

In another example, the control system 86 can modify an annulus 20 volume used by the hydraulics and/or well model(s) automatically in response to the step 130 output indicating that a floating rig is heaving. For example, the
10 control system 86 could receive indications of rig heave from a conventional motion compensation system of the floating rig. The annulus 20 volume can be modified/corrected by the control system 86 automatically in response to indications that the rig has risen or fallen,
15 thereby enabling the annulus, wellbore or standpipe pressure set point to be updated based on the modified/corrected annulus volume.

SUCTION PUMP EXAMPLES

Referring additionally now to FIG. 6, a more detailed elevational view of the suction pump 66 is representatively illustrated, apart from the remainder of the system 10. In this example, the pump 66 draws the fluid 18 from a
20 reservoir 140, which is in communication with the annulus 20 (or which is itself a section of the annulus), such that a level of the fluid 18 in the reservoir 140 corresponds to a fluid level in the annulus.
25

Thus, if the pump 66 reduces the level of the fluid 18 in the reservoir 140 (e.g., by drawing fluid from the
30 reservoir at a greater rate than the fluid is flowed into the reservoir from the annulus 20), hydrostatic pressure in the reservoir and annulus is reduced. Conversely, if the

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pump 66 increases the level of the fluid 18 in the reservoir 140 (e.g., by drawing fluid from the reservoir at a rate less than the fluid is flowed into the reservoir from the annulus 20), hydrostatic pressure in the reservoir and
5 annulus is increased.

Note that, in this example, the reservoir 140 is open to atmosphere at the surface. Thus, the pump 66 could possibly (in certain circumstances) reduce the level of the fluid 18 in the reservoir 140 to the extent that air enters
10 a suction conduit 138 for the pump 66.

This event (air drawn into the pump 66) could be an indication that an undesired loss of fluid 18 is occurring downhole. The event can be detected, for example, by detecting a horsepower input to the pump 66 (e.g., by
15 monitoring electrical power draw by a pump with an electric motor, monitoring revolutions per minute of a diesel motor-powered pump, etc.).

In one example, the horsepower input to the pump 66 (or parameter values based at least in part on the suction pump
20 horsepower) could be used in the event signatures described above. FIG. 5 depicts the suction pump horsepower as one of the parameters in the kick and loss event signatures. It is conceived that the air drawn into the pump 66 will cause horsepower input to increase (e.g., in an attempt to draw
25 the fluid 18 into the suction line 138), but other techniques for detecting this event may be used, in keeping with the scope of this disclosure.

Other factors can cause the suction pump 66 horsepower to change. For example, a change in properties (e.g.,
30 viscosity, density, temperature, gas content, etc.) of the fluid 18 can cause a change in the pump horsepower input for a corresponding flow rate, rpm, etc. Thus, an influx of

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formation fluid into the wellbore 12, or a loss of fluid 18 from the wellbore, could be detected by monitoring parameters related to the suction pump 66.

A person skilled in the art will understand that, in practice, the pump 66 specifications should provide for adequate net positive suction head, static suction lift and static discharge lift for a particular drilling operation. Some factors to consider in the design of the pump 66 include specific gravity, viscosity and temperature of the fluid 18 to be pumped, the pump's elevation (e.g., relative to sea level), atmospheric pressure, size and length of the suction and discharge lines 138, 136, range of fluid levels in the reservoir 140 to achieve corresponding desired pressure variations in the well, presence of particles (such as drill cuttings) in the fluid, etc.

Referring additionally now to FIG. 7, another configuration of the system 10 is representatively illustrated. In this example, the annulus 20 is closed to the atmosphere at the surface, and the suction pump 66 is connected to the annulus below the RCD 22 and above the BOP stack 42. The annulus 20 is preferably closed to the atmosphere in underbalanced and managed pressure drilling operations, where unacceptable production of gas is possible, and/or where a pressure control technique (such as, applying suction pressure to the annulus, etc.) is facilitated by closing off the annulus at the surface.

The discharge line 136 can be connected to the fluid return line 30, to a discharge 134 at an elevation higher than the pump 66, to a discharge 132 at an elevation substantially the same as that of the pump, and/or to a discharge 130 at an elevation lower than the pump. The discharges 132, 134, 136 (and the return line 30, as

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depicted in FIG. 1) can be connected to the choke manifold 32, separator 48, shaker 50 and/or mud pit 52.

The suction pump 66, in this example, can reduce pressure in the annulus 20 at the surface (and thereby
5 reduce pressure at any location in the wellbore 12) by drawing fluid 18 from the annulus at a greater rate than the fluid is injected into the drill string 16 by the rig pump 68 (accounting for fluid lost to or gained from the formation 64, cuttings carried with the fluid, etc.).
10 Conversely, the suction pump 66 can increase pressure in the annulus 20 at the surface (and thereby increase pressure at any location in the wellbore 12) by drawing fluid 18 from the annulus at a rate less than the fluid is injected into the drill string 16 by the rig pump 68 (accounting for fluid
15 lost to or gained from the formation 64, cuttings carried with the fluid, etc.).

If the fluid 18 is not being injected into the drill string 16 by the rig pump 68 (such as, while a connection is being made, or while the drill string is being tripped out
20 of the wellbore 12, etc.), then the pump 66 can still be used to control pressure in the wellbore. For example, the pump 66 in the FIG. 6 example could be used to control the level of the fluid 18 in the annulus 20, and if the wellbore 12 is closed to the atmosphere as in the FIG. 7 example, the
25 pump could be used to vary pressure in the wellbore by varying a suction pressure applied by the pump, etc.

Thus, the controller 84 can control operation of the pump 66 to automatically maintain a desired annulus, wellbore or standpipe pressure set point. When the fluid 18
30 is circulating through the drill string 16 and annulus 20, the operation of the pump 66 (e.g., flow rate, horsepower input, rpm, etc.) can be controlled relative to the rig pump

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68, so that the annulus, wellbore or standpipe pressure set point is maintained.

In one technique, the annulus 20, wellbore 12 and/or standpipe 26 pressure is/are monitored in real time (e.g.,
5 using the sensors 36, 60, 44) and, when a monitored pressure is less than the respective set point, the flow rate through the suction pump 66 is decreased to thereby increase the pressure, and when the monitored pressure is greater than the respective set point, the flow rate through the pump is
10 increased to thereby decrease the pressure. This control can be performed automatically, in response to human command, etc.

Note that the suction pump 66 can be used to circulate the fluid 18 through the drill string 16 and annulus 12,
15 even if the rig pump 68 is not used to inject the fluid into the drill string. For example, in the FIG. 7 configuration, the suction pump 66 can draw the fluid 18 from the mud pit 52 (see FIG. 1) to the standpipe 26, and then through the drill string 16 and annulus 20 back to the surface. This can
20 be done whether or not the rig pump 68 is interconnected between the mud pit 52 and the standpipe 26.

In some examples, the suction pump 66 can be used to regulate pressure in the wellbore 12 while a connection is being made in the drill string 16, whether or not the fluid
25 18 is flowing through the drill string and annulus 20 while the connection is being made. If the fluid 18 does flow through the drill string 16 while the connection is being made, either of the FIGS. 6 & 7 configurations may be used to regulate wellbore pressure.

30 If the fluid 18 does not flow through the drill string 16 while the connection is being made, the FIG. 6 configuration may be more preferable, since hydrostatic

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pressure in the wellbore 12 can be conveniently adjusted by varying the level of the fluid 18 in the reservoir 140. For example, the level of the fluid 18 in the reservoir 140 can be reduced while circulation is substantially ceased, in order to account for reduced friction pressure. However, the FIG. 7 configuration could be used to regulate wellbore pressure during the connection, for example, if a valve or other flow control device is used to prevent flow of the fluid 18 through the drill string 16.

Equivalent circulating density (ECD) is a paradigm used by those skilled in the art to describe the effect of circulation on pressure in a well environment. Without such circulation (i.e., in a static condition), pressure at a location in the wellbore 12 is equal to hydrostatic pressure due to the density of the fluid 18 and a height of a column of the fluid (e.g., true vertical depth of the fluid). With circulation (i.e., in a dynamic condition), pressure at that location is equal to hydrostatic pressure (as in the static condition), plus friction pressure lost in flowing the fluid back to the surface. ECD is a theoretical adjusted density of the fluid 18 to account for the friction pressure addition to the hydrostatic pressure.

When it is considered that the friction pressure is a function in part of the pressure differential across the flow path the fluid 18 traverses (e.g., including the drill string 16 and annulus 20 in the system 10 example), it will be appreciated that by using the suction pump 66 to adjust the pressure in the annulus at or near the surface, the pressure differential across the annulus (and across the drill string, etc.) can be correspondingly adjusted. Therefore, it can be considered that, by adjusting the operation of the suction pump 66, the ECD in the system 10 is correspondingly adjusted.

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In one technique, the suction pump 66 can be used to increase ECD by increasing the pressure differential across the annulus 20, and the pump can be used to decrease ECD by decreasing the pressure differential across the annulus. In
5 typical circumstances, it will likely be most desirable to maintain a pressure set point at a particular location (such as, in the annulus 20 at or near the surface, at another wellbore 12 location, in the standpipe 26, etc.), and adjustment of the ECD can be a useful technique for
10 maintaining the pressure set point.

Referring additionally now to FIG. 8, another example of the system 10 is representatively illustrated. In this example, the return line 30 is connected to the annulus 20 via the wing valve 28 positioned between an annular blowout
15 preventer (BOP) 144 and another annular seal 146 (such as, another annular BOP, a Shaffer Pressure Control While Drilling (PCWD) device, an RCD, etc.).

The annular seal 146 does not necessarily seal against a pressure differential, but preferably does at least
20 isolate the annulus 20 from the earth's atmosphere. Thus, the annulus 20 is not necessarily pressurized at or near the surface, but may instead be substantially balanced while the suction pump 66 pumps the fluid 18 from the annulus. The annular seal 146 seals off the annulus 20 between the drill
25 string 16 and an outer housing of the BOP stack 42 above the wing valve 28.

Note that the fluid 18 can, in the FIG. 8 example, exit the BOP stack 42 via another wing valve 148 positioned below the lower annular BOP 144. In this manner, the suction pump
30 66 can receive the fluid 18 from lower in the annulus 20. In some examples, this can enable the suction pump 66 to draw down the level of the fluid 18 in the annulus 20 (or in a

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reservoir 140 connected to the annulus), thereby reducing the hydrostatic pressure in the wellbore 12. Only one of the wing valves 28, 148 is preferably open at a time.

It can now be fully appreciated that significant
5 advancements are provided to the art of controlling well pressure by the above disclosure. In one example, the systems and methods described above allow well pressure to be conveniently adjusted by controlling operation of the suction pump 66 connected to the wellbore 12 via the annulus
10 20. In other examples, an increase in a rate of fluid drawn from the annulus 20 by the pump 66 produces a corresponding decrease in pressure in the wellbore 12, and a decrease in the rate of fluid drawn from the annulus by the pump produces a corresponding increase in pressure in the
15 wellbore. The variations in pressure can be due to corresponding changes in the level of the fluid 18 in the annulus 20 (e.g., in the FIG. 6 example), changes in suction pressure (reduced pressure, preferably less than atmospheric pressure) applied to the annulus (e.g., in the FIG. 7
20 example), etc. Parameters related to the pump 66 (such as, pump horsepower, flow rate, rpm, pressure at a suction side of the pump, pressure differential across the pump, etc.) can be used for event detection purposes, for example, to detect whether a fluid loss or influx has occurred, or is
25 about to occur.

In one example described above, a well pressure control method can include regulating pressure in a wellbore 12 by operating a suction pump 66 which draws fluid 18 from an annulus 20 formed between a drill string 16 and the wellbore
30 12, the fluid 18 entering the suction pump 66 proximate the earth's surface.

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Operating the suction pump 66 can include increasing a rate of fluid 18 drawn from the annulus 20 by the suction pump 66, thereby reducing the wellbore 12 pressure.

Operating the suction pump 66 can include decreasing a rate
5 of the fluid 18 drawn from the annulus 20 by the suction pump 66, thereby increasing the wellbore 12 pressure.

Regulating pressure may include maintaining an annulus pressure, wellbore pressure and/or standpipe pressure set point.

10 Operating the suction pump 66 can include varying a flow rate of the suction pump 66 relative to a flow rate of a rig pump 68 which injects the fluid 18 into the drill string 16.

The method can include detecting an event based on
15 sensing at least one suction pump 66 parameter. The suction pump 66 parameter may comprise at least one of a group including pump horsepower, suction pressure, pressure differential across the pump, flow rate, and revolutions per minute. The event may comprise an undesired influx from a
20 formation 64 into the wellbore 12, or an undesired loss from the wellbore 12 into the formation 64. The suction pump 66 parameter may comprise a lack of the fluid 18 entering the suction pump 66.

The method can include determining a property of the
25 fluid 18 based on a sensed suction pump 66 parameter. The fluid 18 property may comprise at least one of a group including viscosity, density, temperature, and gas content.

Operating the suction pump 66 can include a control
system 86 causing the suction pump 66 to change the wellbore
30 12 pressure in response to detection of an event. The event may comprise an undesired influx into the wellbore 12, and the control system 86 may cause the suction pump 66 to

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increase the wellbore 12 pressure in response to the detection of the undesired influx. The event may comprise an undesired loss from the wellbore 12, and the control system 86 may cause the suction pump 66 to reduce the wellbore 12 pressure in response to the detection of the undesired loss. The increase or reduction in the wellbore 12 pressure caused by the suction pump 66 may be followed by, or accompanied by the choke 34 being operated to respectively increase or reduce the wellbore 12 pressure.

The control system 86 may automatically cause the suction pump 66 to change the wellbore 12 pressure in response to the detection of the event. The control system 86 may cause the suction pump 66 to change the wellbore 12 pressure by a predetermined amount in response to the detection of the event.

Operating the suction pump 66 may comprise varying a fluid 18 level in a reservoir 140, thereby varying hydrostatic pressure in the wellbore 12. Varying the fluid 18 level in the reservoir 140 can include reducing the fluid 18 level while flow of the fluid 18 through the drill string 16 is substantially ceased.

Regulating the wellbore 12 pressure can include maintaining a desired fluid 18 level in a reservoir 140, thereby maintaining a desired hydrostatic pressure in the wellbore 12.

Operating the suction pump 66 can comprise varying a suction pressure applied to the annulus 20 by the suction pump 66.

Regulating the wellbore 12 pressure may comprise maintaining a desired suction pressure applied to the annulus 20 proximate the earth's surface.

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The suction pressure can be less than atmospheric pressure.

Operating the suction pump 66 can be performed while flow of the fluid 12 through the drill string 16 is
5 substantially ceased, while making a connection in the drill string 16, and/or while substantially no injection of the fluid 18 into the drill string 16 is occurring.

The suction pump 66 may draw the fluid 18 through the drill string 16 and annulus 20, without any rig pump 68
10 injecting the fluid 18 into the drill string 16.

The above disclosure also describes, in one example, another well pressure control method which can include regulating pressure in a wellbore 12 by operating a suction pump 66 which applies suction pressure to an annulus 20
15 formed between a drill string 16 and the wellbore 12.

The suction pump 66 may receive fluid 18 which exits the annulus 20 below an annular blowout preventer 144, between an annular seal 146 and an annular blowout preventer 144, and/or between two annular blowout preventers 144, 146.

20 In one example described above, a well drilling system 10 can comprise a suction pump 66 positioned proximate the earth's surface. The suction pump 66 receives fluid 18 which exits an annulus 20 formed between a drill string 16 and a wellbore 12.

25 It is to be understood that the various embodiments of this disclosure described herein may be utilized in various orientations, such as inclined, inverted, horizontal, vertical, etc., and in various configurations, without departing from the principles of this disclosure. The
30 embodiments are described merely as examples of useful

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applications of the principles of the disclosure, which is not limited to any specific details of these embodiments.

In the above description of representative examples, directional terms (such as "above," "below," "upper,"
5 "lower," etc.) are used for convenience in referring to the accompanying drawings. However, it should be clearly understood that the scope of this disclosure is not limited to any particular directions described herein.

Of course, a person skilled in the art would, upon a
10 careful consideration of the above description of representative embodiments of the disclosure, readily appreciate that many modifications, additions, substitutions, deletions, and other changes may be made to the specific embodiments, and such changes are contemplated
15 by the principles of this disclosure. Accordingly, the foregoing detailed description is to be clearly understood as being given by way of illustration and example only, the spirit and scope of the invention being limited solely by the appended claims and their equivalents.

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WHAT IS CLAIMED IS:

1. A well pressure control method, comprising:

regulating pressure in a wellbore by operating a suction pump which receives fluid that exits an annulus formed between a drill string and the wellbore, the fluid entering the suction pump proximate the earth's surface, wherein operating the suction pump comprises:

- a) increasing a rate of the fluid drawn from the annulus by the suction pump, thereby reducing the wellbore pressure;
- b) decreasing a rate of the fluid drawn from the annulus by the suction pump, thereby increasing the wellbore pressure;
- c) varying a flow rate of the suction pump relative to a flow rate of a rig pump which injects the fluid into the drill string;
- d) varying a fluid level in a reservoir, thereby varying hydrostatic pressure in the wellbore, wherein varying the fluid level in the reservoir further comprises increasing the fluid level while flow of the fluid through the drill string is substantially ceased;
- e) varying a suction pressure applied to the annulus by the suction pump; or
- f) the suction pump drawing the fluid through the drill string and annulus, without any rig pump injecting the fluid into the drill string.

2. The method of claim 1, wherein regulating pressure further comprises:

- a) maintaining an annulus pressure set point;
- b) maintaining a wellbore pressure set point;
- c) maintaining a standpipe pressure set point;
- d) maintaining a desired fluid level in a reservoir, thereby maintaining a desired hydrostatic pressure in the wellbore;
- e) maintaining a desired suction pressure applied to the annulus proximate the earth's surface, wherein the suction pressure comprises less than atmospheric pressure.

3. The method of claim 1, further comprising detecting an event based on sensing at least one suction pump parameter, wherein:

- a) the suction pump parameter comprises at least one of a group including pump horsepower, suction pressure, pressure' differential across the pump, flow rate, and revolutions per minute;
- b) the event comprises an undesired influx from a formation into the wellbore;

c) the event comprises an undesired loss from the wellbore into a formation wherein the suction pump parameter comprises a lack of the fluid entering the suction pump.

4. The method of claim 1, further comprising determining a property of the fluid based on a sensed suction pump parameter, wherein the fluid property comprises at least one of a group including viscosity, density, temperature, and gas content.

5. The method of claim 1, wherein operating the suction pump further comprises a control system causing the suction pump to change the wellbore pressure in response to detection of an event, wherein:

a) the event comprises an undesired influx into the wellbore, and wherein the control system causes the suction pump to increase the wellbore pressure in response to the detection of the undesired influx;

b) the event comprises an undesired loss from the wellbore, and wherein the control system causes the suction pump to reduce the wellbore pressure in response to the detection of the undesired loss;

c) the control system automatically causes the suction pump to change the wellbore pressure in response to the detection of the event; or

d) the control system causes the suction pump to change the wellbore pressure by a predetermined amount in response to the detection of the event.

6. The method of claim 1, wherein operating the suction pump is performed:

a) while flow of the fluid through the drill string is substantially ceased; or

b) while making a connection in the drill string; or

c) while substantially no injection of the fluid into the drill string is occurring.

7. The method of claim 1, wherein the fluid exits the annulus below an annular blowout preventer, between an annular seal and an annular blowout preventer, or between two annular blowout preventers.

8. A well drilling system, comprising:

a suction pump positioned proximate the earth's surface, and wherein the suction pump receives fluid which exits an annulus formed between a drill string and a wellbore, wherein within the system:

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a) an increase in a rate of the fluid drawn from the annulus by the suction pump reduces the wellbore pressure;

b) a decrease in a rate of the fluid drawn from the annulus by the suction pump increases the wellbore pressure;

c) an annulus pressure set point is maintained by flow of the fluid through the suction pump;

d) a wellbore pressure set point is maintained by flow of the fluid through the suction pump;

e) a standpipe pressure set point is maintained by flow of the fluid through the suction pump; or

f) a flow rate of the suction pump is varied relative to a flow rate of a rig pump which injects the fluid into the drill string.

9. The system of claim 8, wherein an event is detected based on at least one sensed suction pump parameter, wherein:

a) the suction pump parameter comprises at least one of a group including pump horsepower, suction pressure, pressure differential across the pump, flow rate, and revolutions per minute;

b) the event comprises an undesired influx from a formation into the wellbore;

c) the event comprises an undesired loss from the wellbore into a formation, wherein the suction pump parameter comprises a lack of the fluid entering the suction pump.

10. The system of claim 8, wherein:

a) a property of the fluid is determined based on a sensed suction pump parameter, wherein the fluid property comprises at least one of a group including viscosity, density, temperature, and gas content;

b) the suction pump varies a fluid level in a reservoir whereby hydrostatic pressure in the wellbore is varied, wherein the suction pump increases the fluid level while flow of the fluid through the drill string is substantially ceased;

c) the suction pump varies a suction pressure applied to the annulus by the suction pump, wherein the suction pressure comprises less than atmospheric pressure; or

d) the suction pump draws the fluid through the drill string and annulus, while no rig pump injects the fluid into the drill string.

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11. The system of claim 8, wherein a control system causes the suction pump to change the wellbore pressure in response to detection of an event, wherein:

a) the control system also operates a choke to change the wellbore pressure in response to detection of the event;

b) the event comprises an undesired influx into the wellbore, and wherein the control system causes the suction pump to increase the well bore pressure in response to the detection of the undesired influx;

c) the event comprises an undesired loss from the wellbore, and wherein the control system causes the suction pump to reduce the wellbore pressure in response to the detection of the undesired loss;

d) the control system automatically causes the suction pump to change the wellbore pressure in response to the detection of the event; or

e) the control system causes the suction pump to change the wellbore pressure by a predetermined amount in response to the detection of the event.

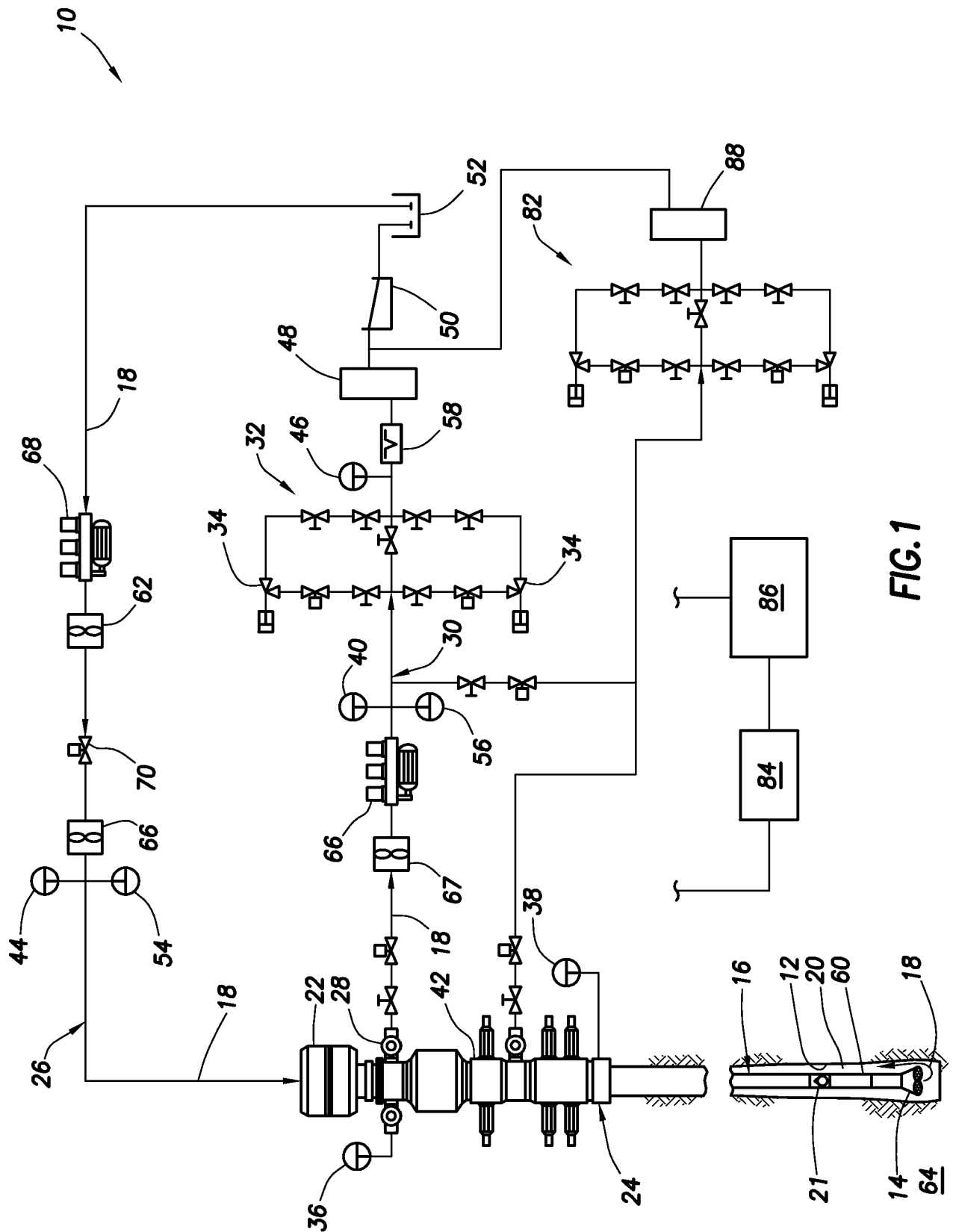
12. The system of claim 8, wherein the suction pump receives the fluid while:

a) flow of the fluid through the drill string is substantially ceased;

b) a connection is made in the drill string; or

c) there is substantially no injection of the fluid into the drill string.

13. The system of claim 8, wherein the fluid exits the annulus below an annular blowout preventer, between an annular seal and an annular blowout preventer, or between two annular blowout preventers.



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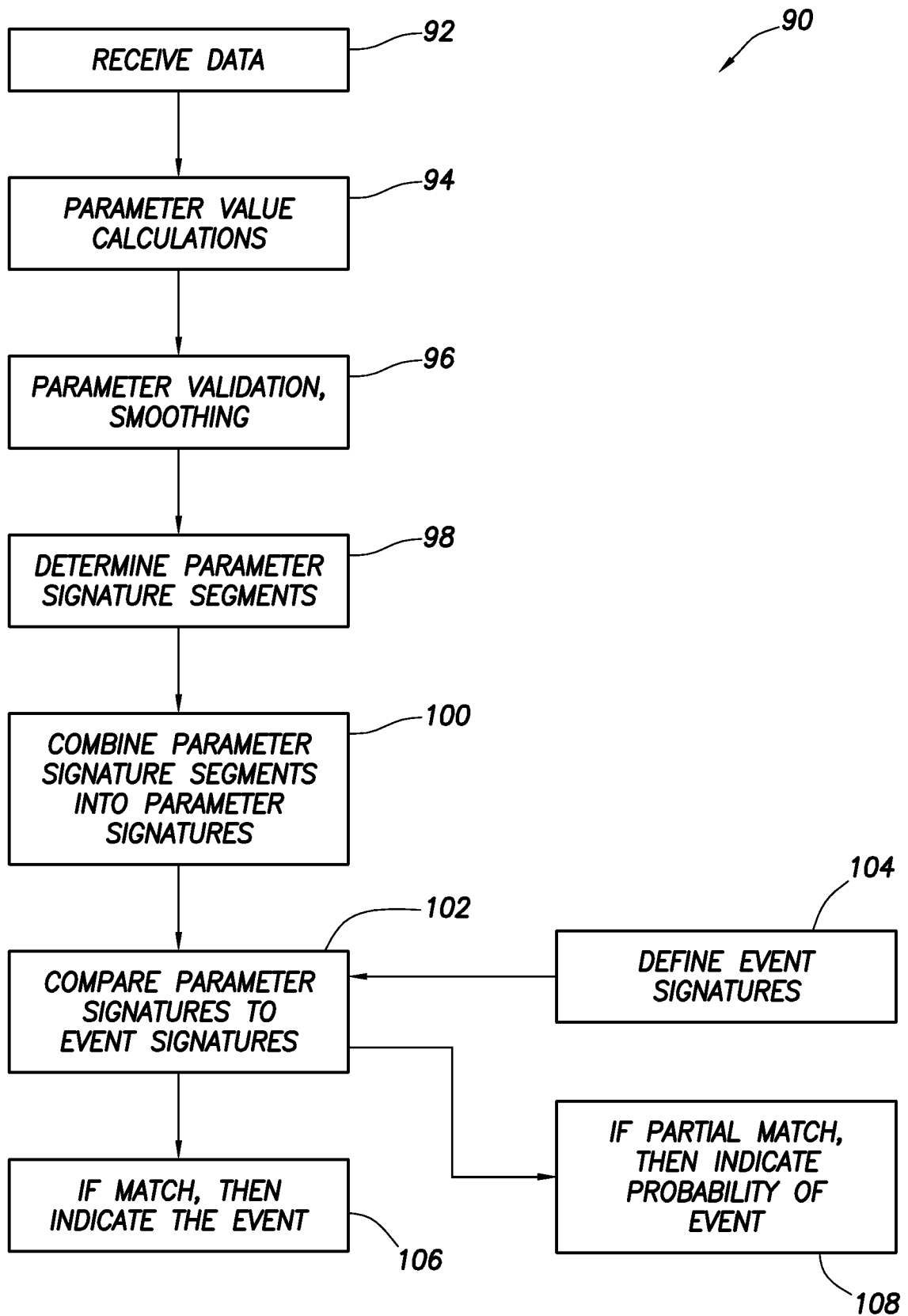


FIG.2

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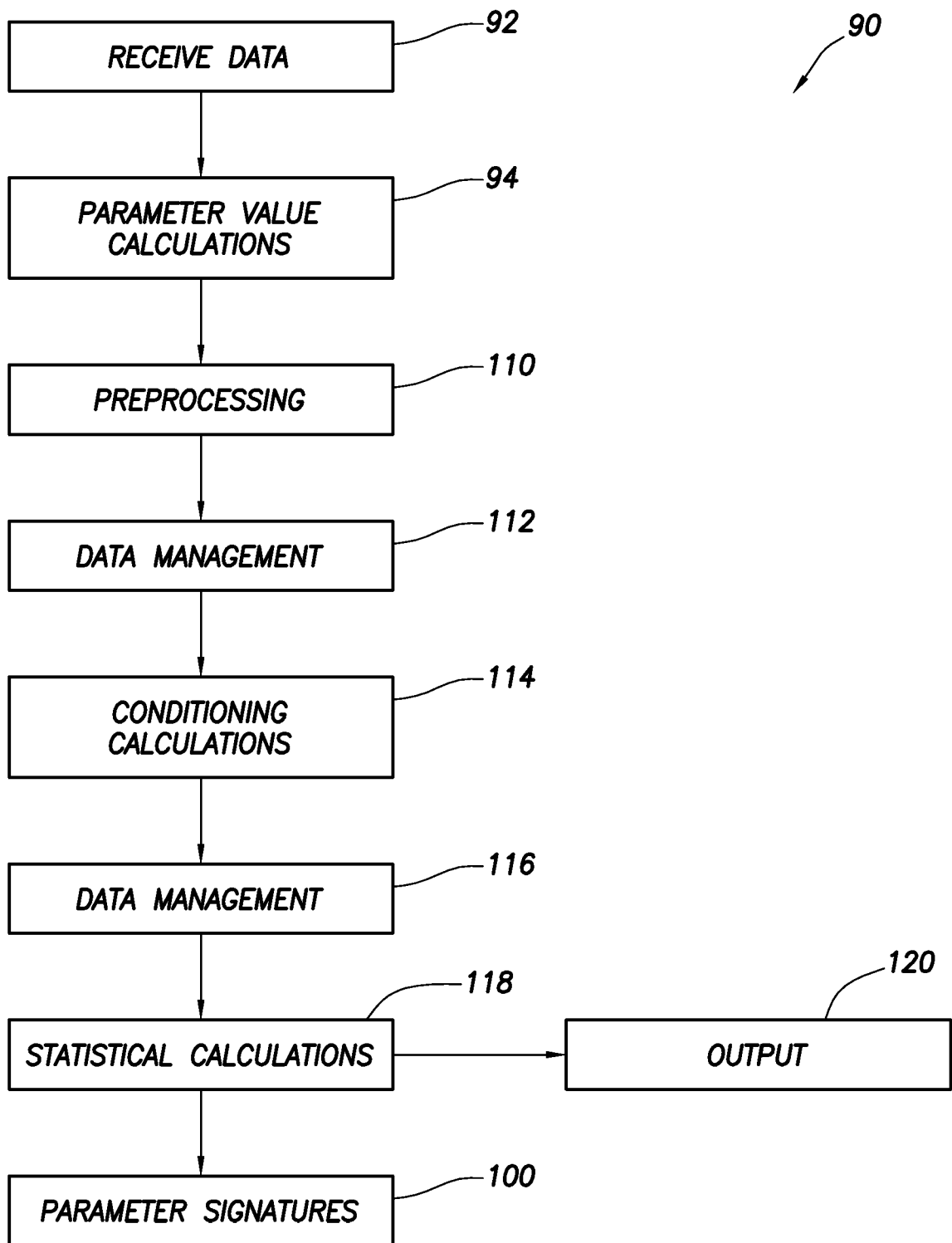


FIG.3

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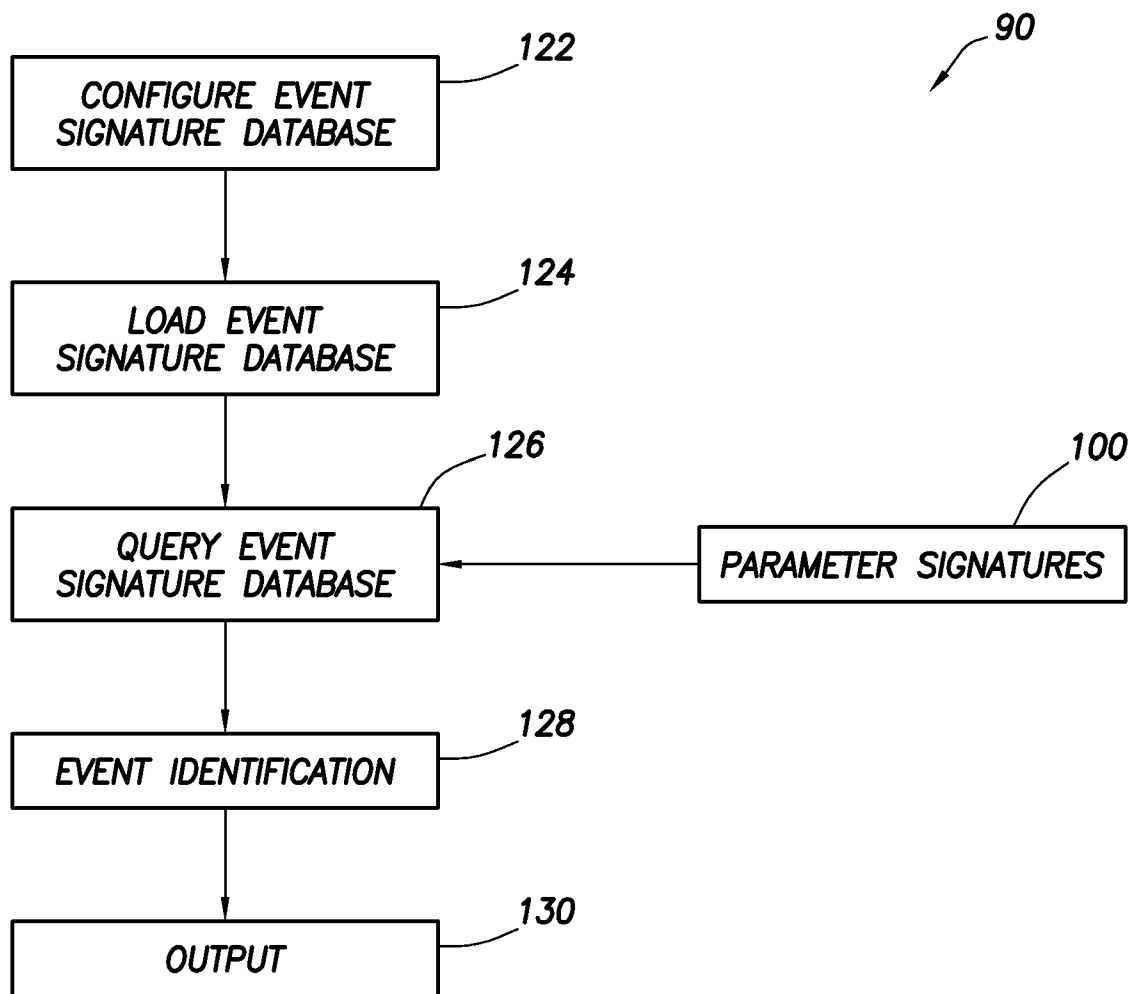


FIG.4

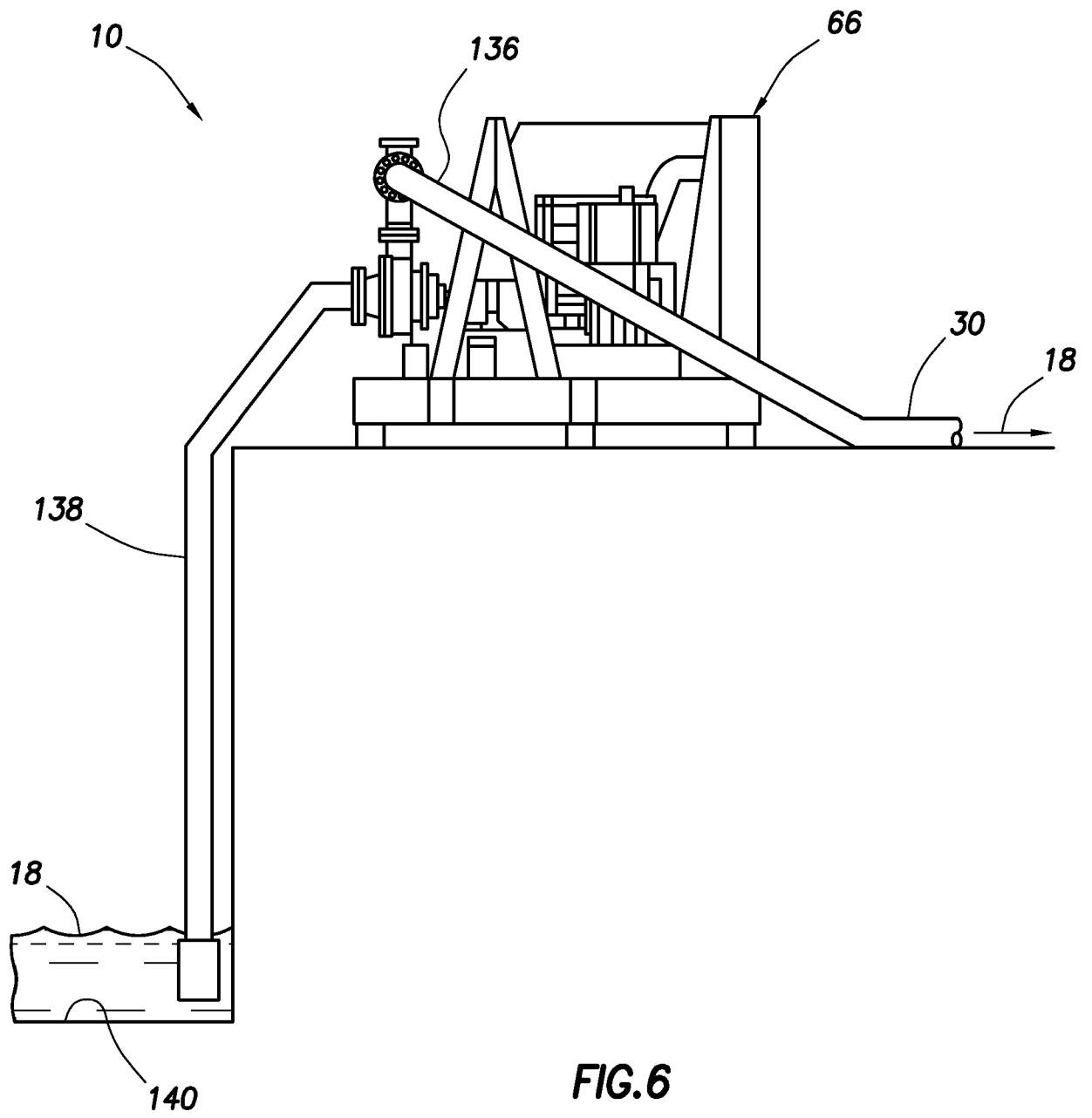
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EVENT SIGNATURES

PARAMETERS	KICK	LOSS
STANDPIPE PRESSURE	DECREASING	INCREASING
UPSTREAM SUCTION PUMP PRESSURE	INCREASING	DECREASING
DOWNSTREAM SUCTION PUMP PRESSURE	INCREASING	DECREASING
BELOW BOP PRESSURE	DECREASING	INCREASING
ANNULUS PRESSURE	DECREASING	INCREASING
BOTTOM HOLE PRESSURE	DECREASING	ERRATIC
SEPARATOR PRESSURE	UNCHANGED	UNCHANGED
UPSTREAM SUCTION PUMP TEMPERATURE	DECREASING	UNCHANGED
DOWNSTREAM SUCTION PUMP TEMPERATURE	DECREASING	UNCHANGED
BOTTOMHOLE TEMPERATURE	DECREASING	UNCHANGED
FLOW IN	UNCHANGED	UNCHANGED
FLOW OUT	INCREASING	DECREASING
SUCTION PUMP HP	DECREASING	INCREASING
BIT DEPTH	N/A	N/A
RATE OF PENETRATION	N/A	N/A
HOOKLOAD	INCREASING	N/A
WEIGHT ON BIT	INCREASING	N/A
RPM	UNCHANGED	N/A
TORQUE	ERRATIC	N/A
CHOKE SIZE	INCREASING	DECREASING
PIT VOLUME	INCREASING	DECREASING
TRIP TANK	INCREASING	DECREASING
MUD WEIGHT IN	UNCHANGED	UNCHANGED
MUD WEIGHT OUT	DECREASING	UNCHANGED
FLOW OUT—FLOW IN	INCREASING	DECREASING

FIG.5

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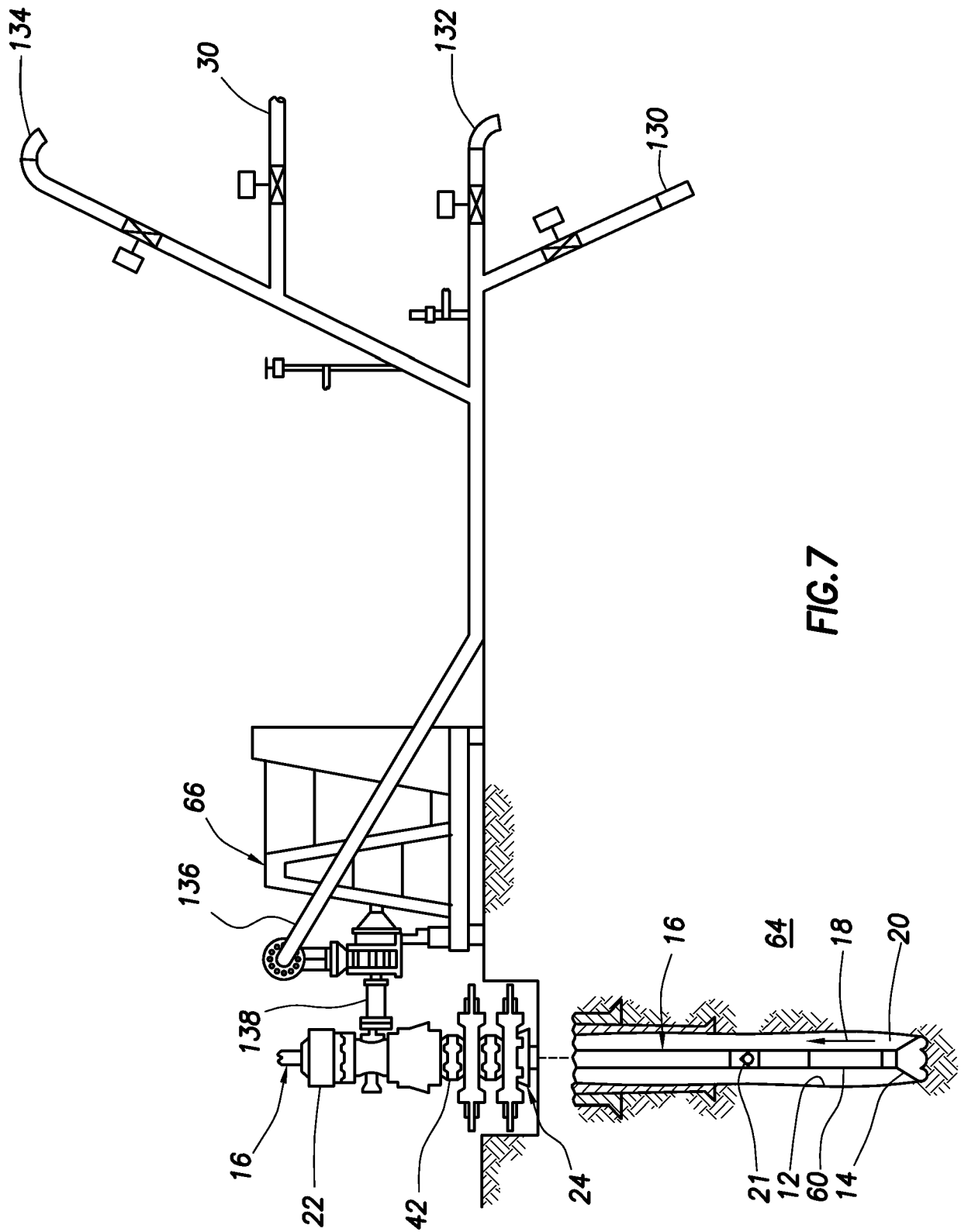


FIG. 7

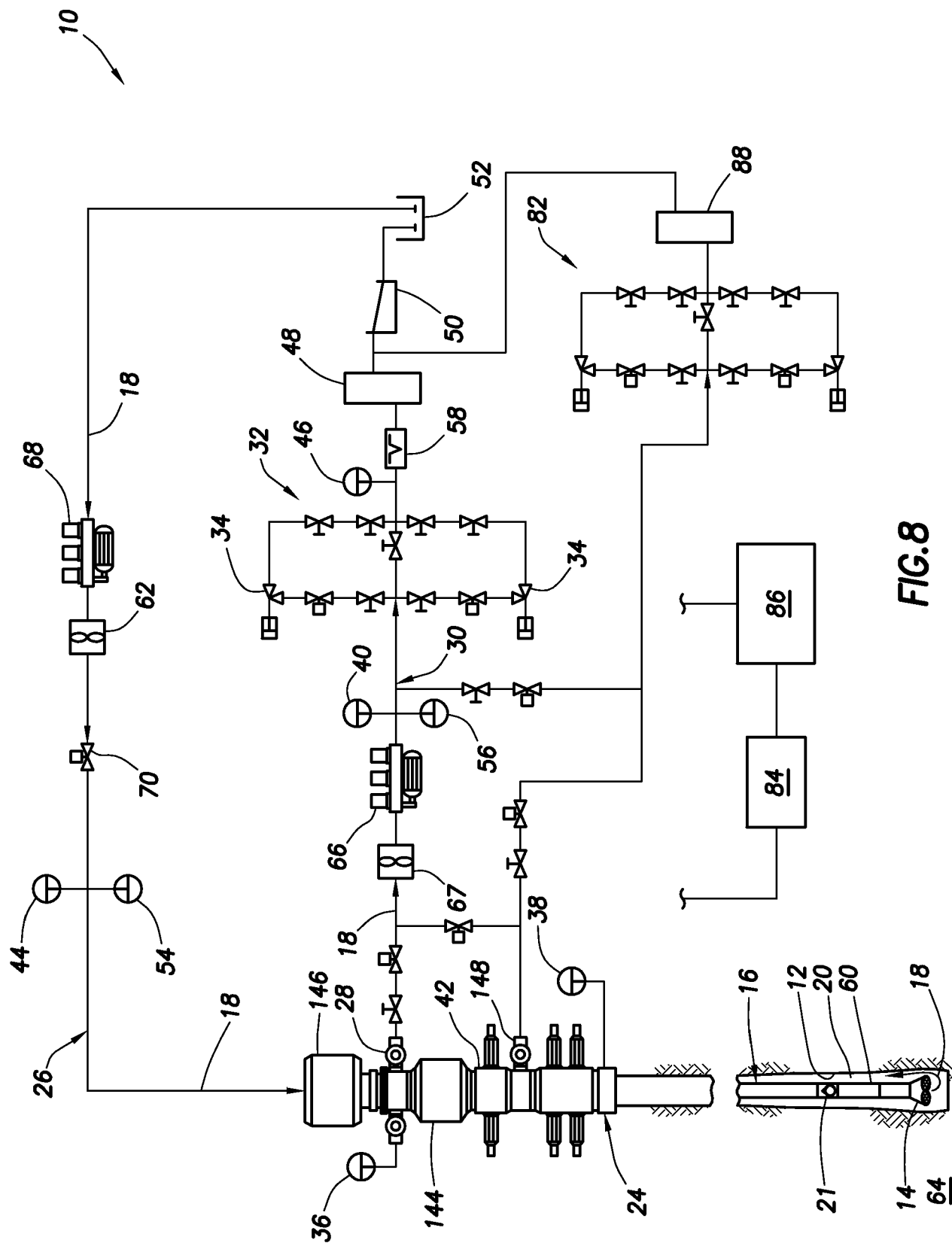


FIG.8