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(54) **PRESSURE CONTROL IN DRILLING OPERATIONS WITH OFFSET APPLIED IN RESPONSE TO PREDETERMINED CONDITIONS**

(76) Inventors: **James R. Lovorn**, Tomball, TX (US); **Nancy S. Davis**, Irving, TX (US); **Cody N. Butler**, Dallas, TX (US)

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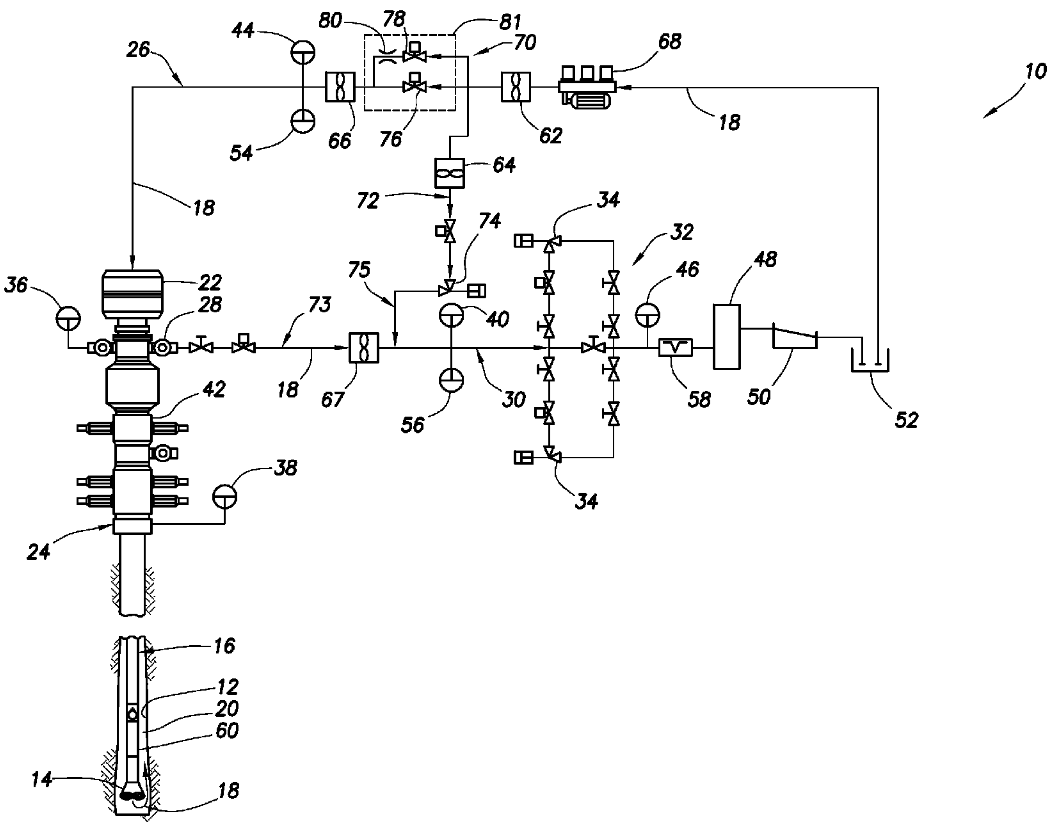
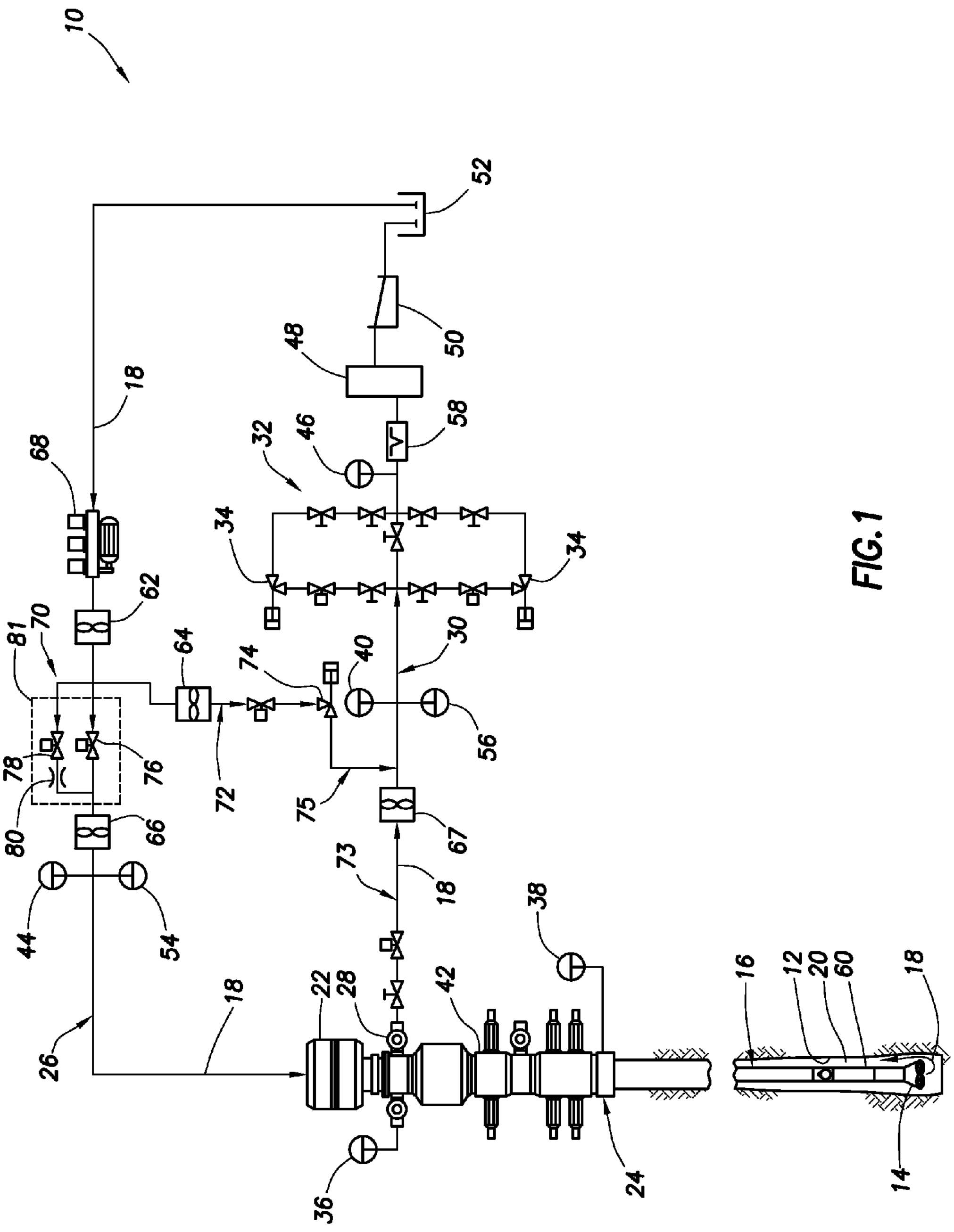
(57) **ABSTRACT**

A method of controlling pressure in a wellbore can include determining a desired well pressure setpoint, adding an offset to the setpoint in response to an actual well pressure deviating from the setpoint by a predetermined amount, and adjusting a flow control device, thereby influencing the actual well pressure toward the setpoint plus the offset. A well system can include a flow control device which variably restricts flow from a wellbore, and a control system which determines a desired well pressure setpoint, compares the setpoint to an actual well pressure, and adds an offset to the setpoint in response to a predetermined amount of deviation between the setpoint and the actual well pressure, whereby the control system adjusts the flow control device, and thereby influences the actual well pressure toward the setpoint plus the offset.




10
52
50
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58
46
32
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18
68
62
70
81
64
74
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78
76
72
75
67
80
66
73
18
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38
22
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18
36
24
16
12
20
60
18
14

FIG. 1

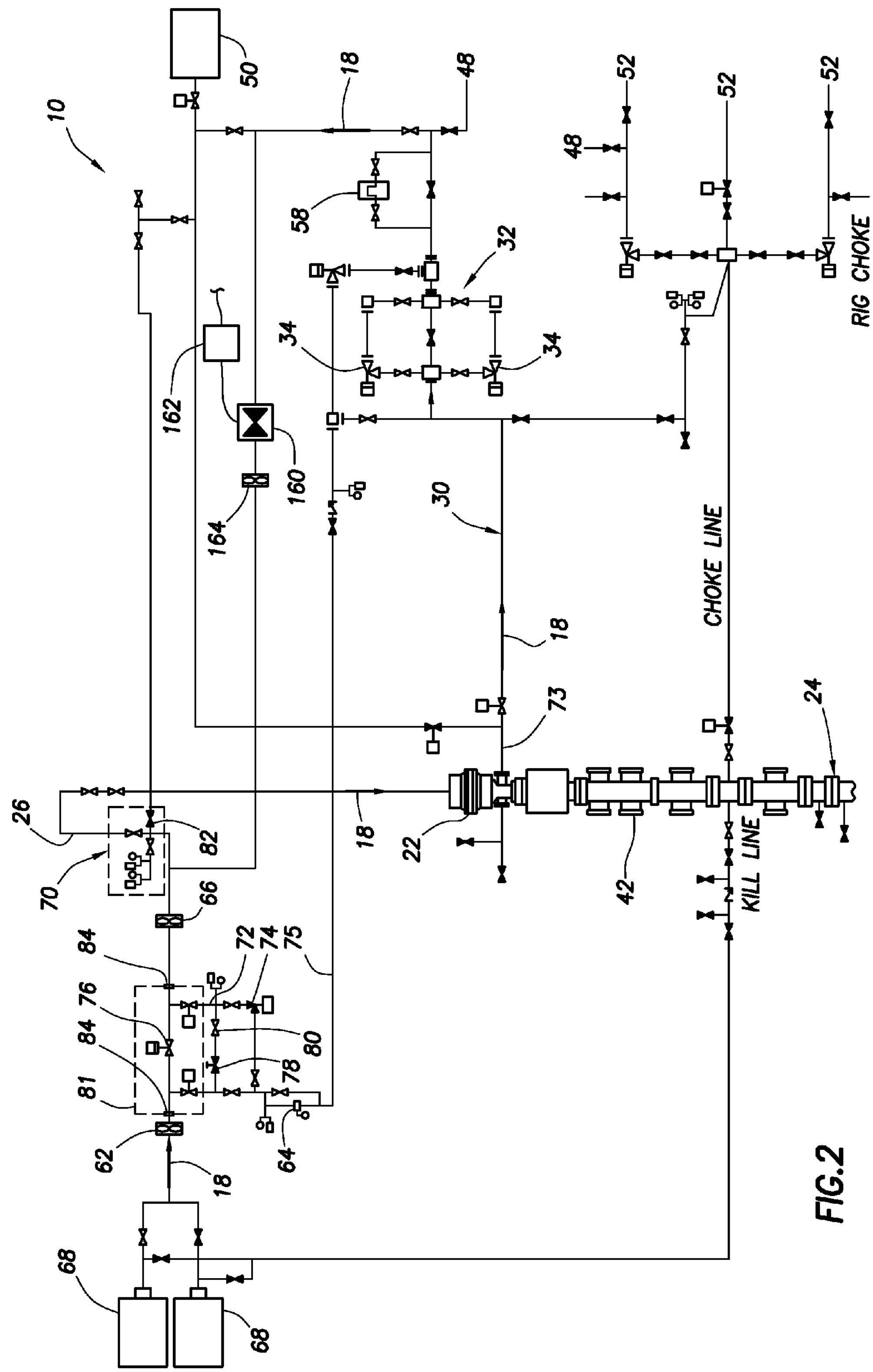
10
50
18
48
52
58
32
34
162
160
164
30
CHOKE LINE
RIG CHOKE
73
24
22
26
82
70
66
84
76
81
72
74
75
80
78
62
64
68
KILL LINE
42

FIG.2

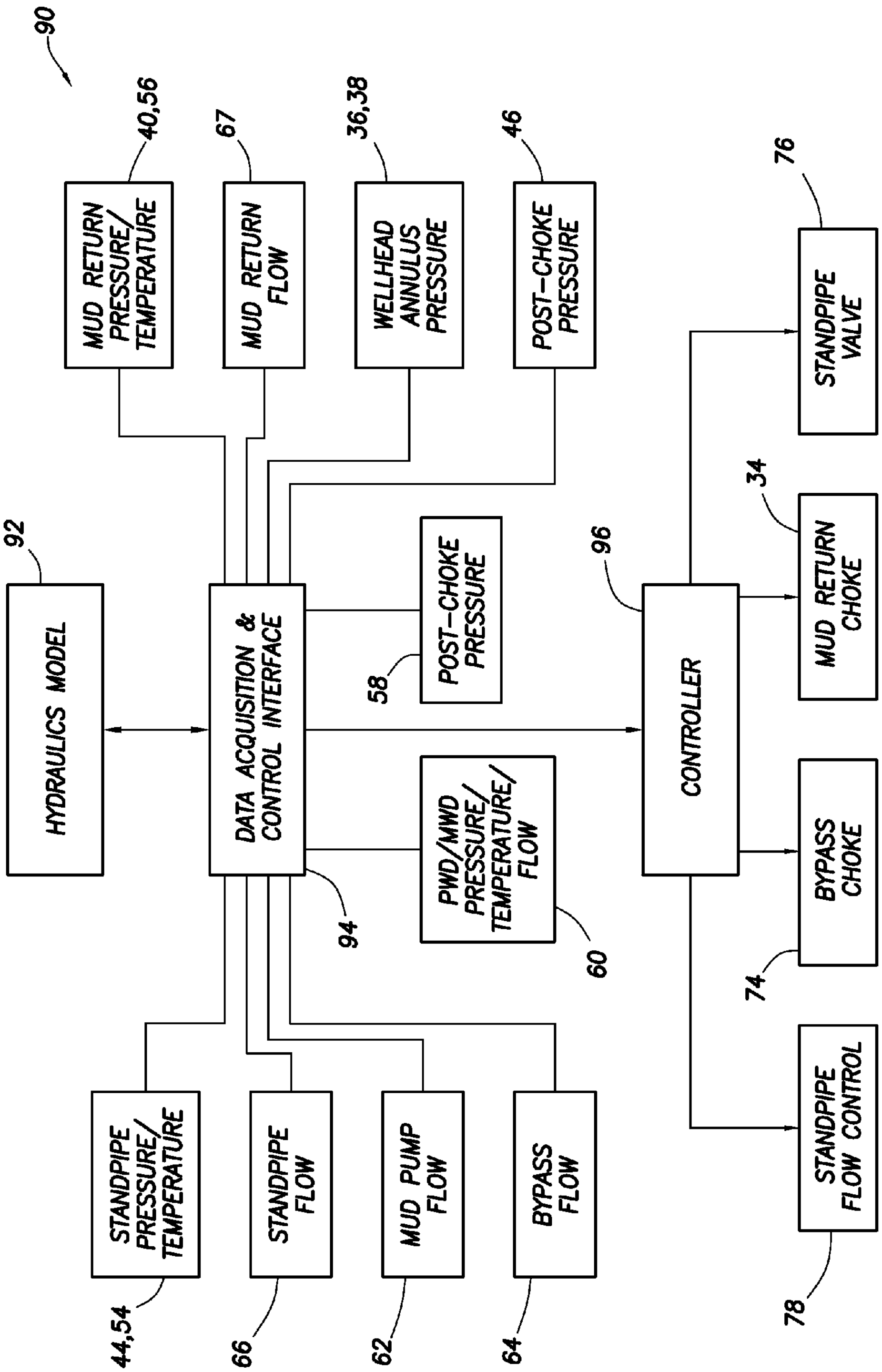
90
HYDRAULICS MODEL
92
DATA ACQUISITION & CONTROL INTERFACE
94
MUD RETURN PRESSURE/ TEMPERATURE
40,56
MUD RETURN FLOW
67
WELLHEAD ANNULUS PRESSURE
36,38
POST-CHOKE PRESSURE
46
POST-CHOKE PRESSURE
58
PWD/MWD PRESSURE/ TEMPERATURE/ FLOW
60
STANDPIPE PRESSURE/ TEMPERATURE
44,54
STANDPIPE FLOW
66
MUD PUMP FLOW
62
BYPASS FLOW
64
CONTROLLER
96
STANDPIPE VALVE
76
MUD RETURN CHOKE
34
BYPASS CHOKE
74
STANDPIPE FLOW CONTROL
78

FIG.3

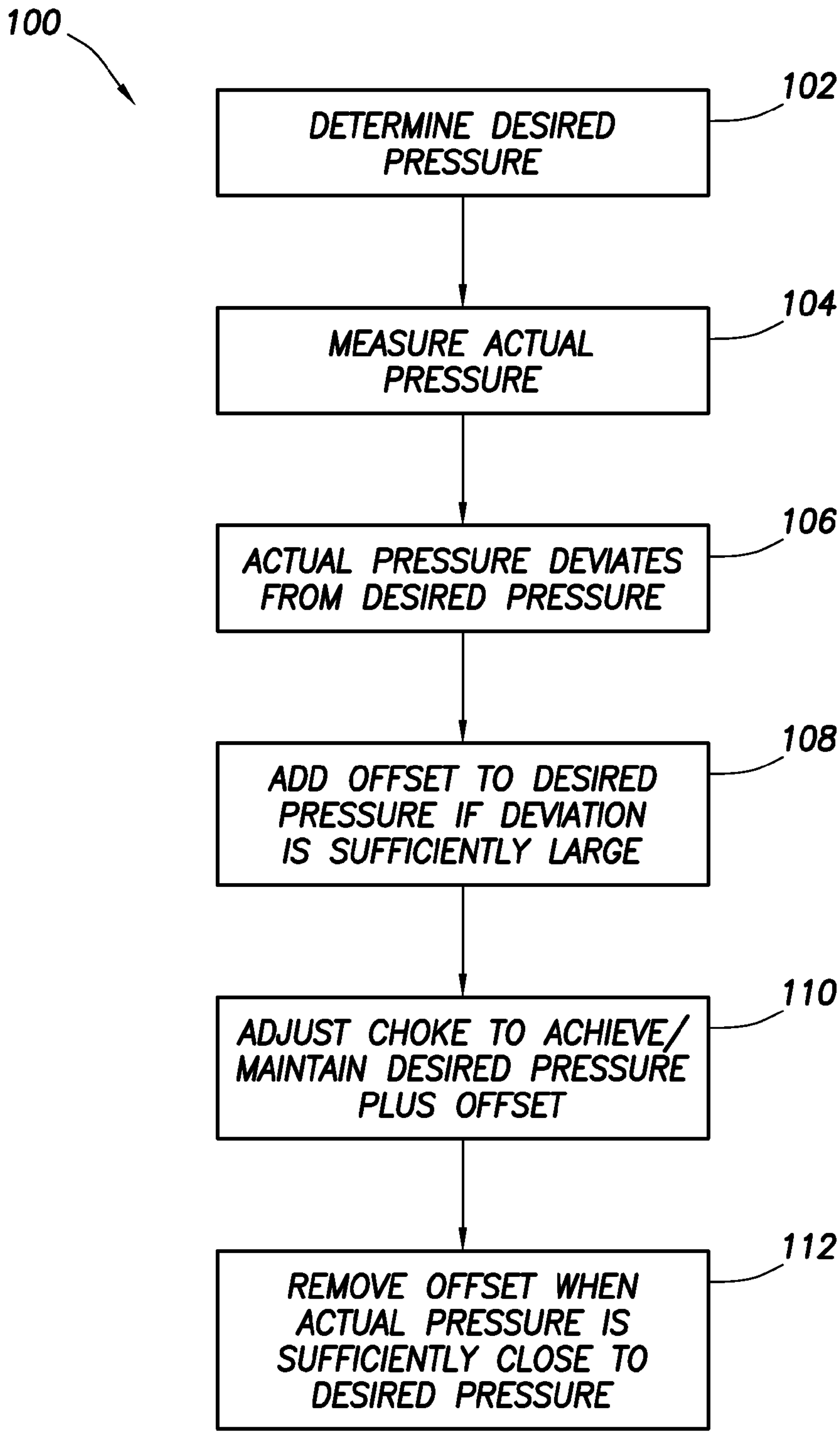
100
DETERMINE DESIRED PRESSURE
102
MEASURE ACTUAL PRESSURE
104
ACTUAL PRESSURE DEVIATES FROM DESIRED PRESSURE
106
ADD OFFSET TO DESIRED PRESSURE IF DEVIATION IS SUFFICIENTLY LARGE
108
ADJUST CHOKE TO ACHIEVE/ MAINTAIN DESIRED PRESSURE PLUS OFFSET
110
REMOVE OFFSET WHEN ACTUAL PRESSURE IS SUFFICIENTLY CLOSE TO DESIRED PRESSURE
112

FIG.4

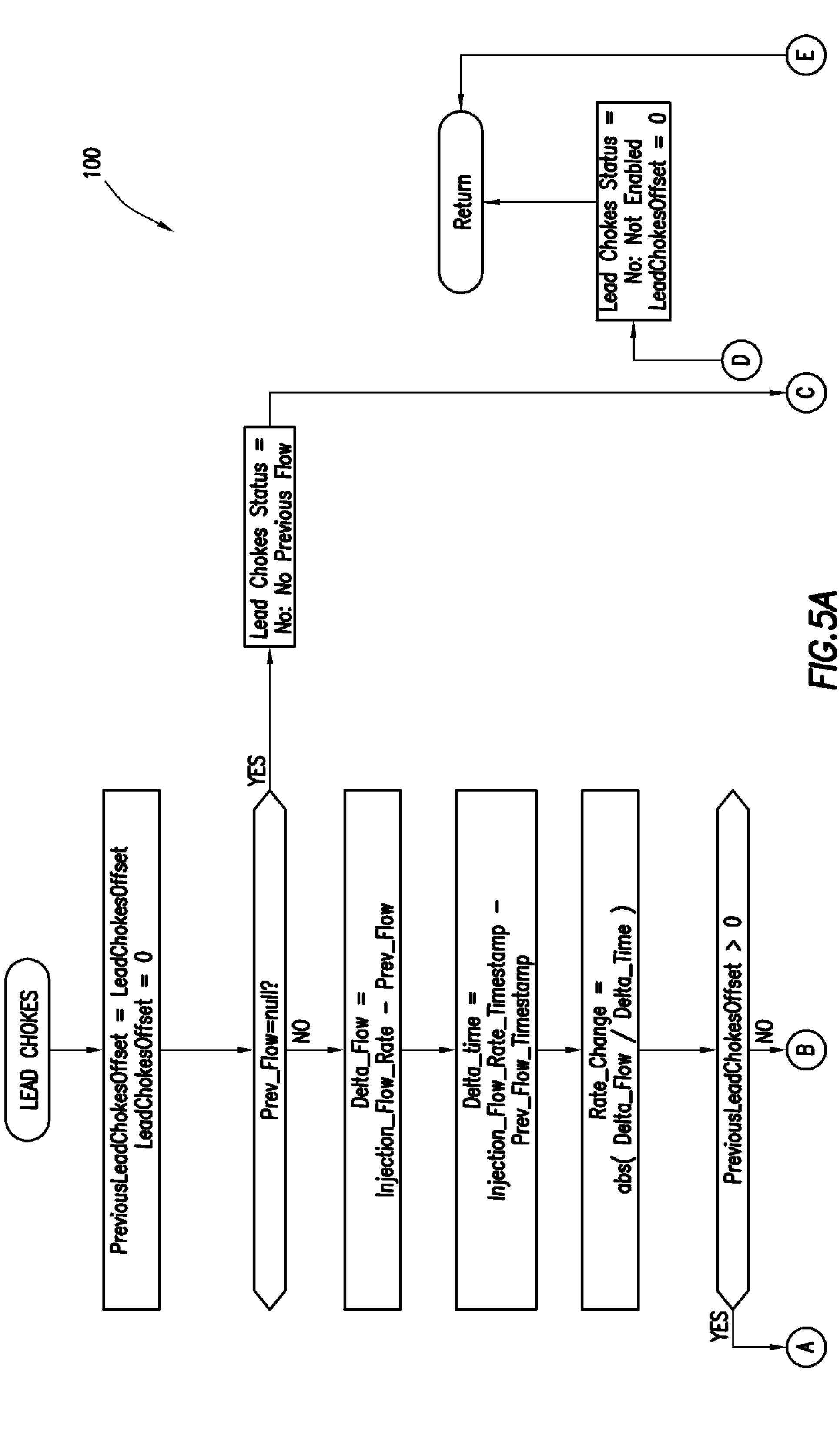
100
LEAD CHOKES
PreviousLeadChokesOffset = LeadChokesOffset
LeadChokesOffset = 0
Prev_Flow=null?
YES
NO
Lead Chokes Status =
No: No Previous Flow
Delta_Flow =
Injection_Flow_Rate − Prev_Flow
Delta_time =
Injection_Flow_Rate_Timestamp −
Prev_Flow_Timestamp
Rate_Change =
abs(Delta_Flow / Delta_Time)
PreviousLeadChokesOffset > 0
YES
NO
A
B
C
D
E
Lead Chokes Status =
No: Not Enabled
LeadChokesOffset = 0
Return

FIG.5A

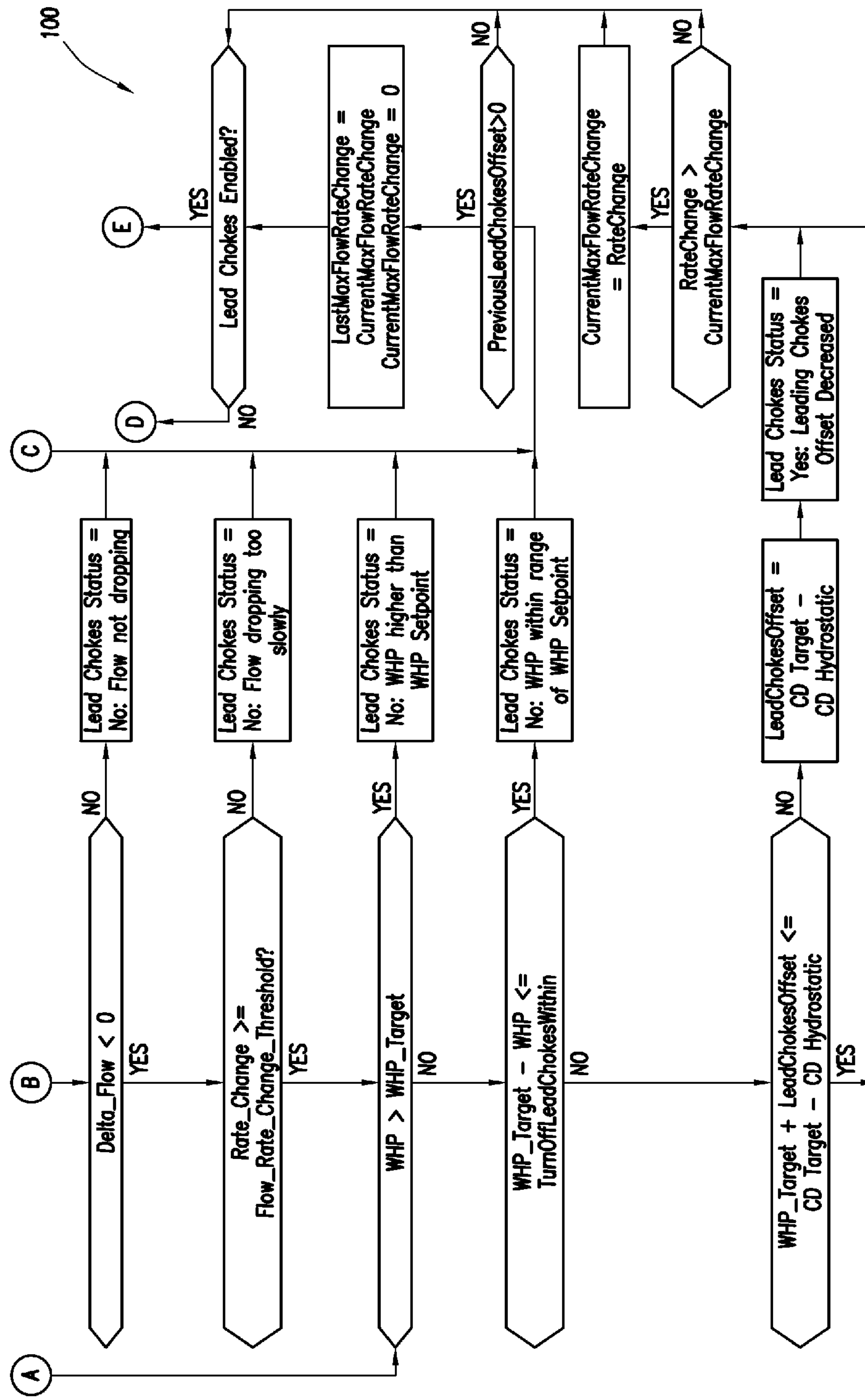
100
A
B
C
D
E
Delta_Flow < 0
YES
NO
Rate_Change >= Flow_Rate_Change_Threshold?
YES
NO
WHP > WHP_Target
YES
NO
WHP_Target − WHP <= TurnOffLeadChokesWithin
YES
NO
WHP_Target + LeadChokesOffset <= CD Target − CD Hydrostatic
YES
NO
LeadChokesOffset = Pumps_Down_Offset
Lead Chokes Status = No: Flow not dropping
Lead Chokes Status = No: Flow dropping too slowly
Lead Chokes Status = No: WHP higher than WHP Setpoint
Lead Chokes Status = No: WHP within range of WHP Setpoint
LeadChokesOffset = CD Target − CD Hydrostatic
Lead Chokes Status = Yes: Leading Chokes Offset Decreased
Lead Chokes Status = Yes: Leading Chokes
RateChange > CurrentMaxFlowRateChange
YES
NO
CurrentMaxFlowRateChange = RateChange
PreviousLeadChokesOffset>0
YES
NO
LastMaxFlowRateChange = CurrentMaxFlowRateChange CurrentMaxFlowRateChange = 0
Lead Chokes Enabled?
YES
NO

FIG.5B

PRESSURE CONTROL IN DRILLING OPERATIONS WITH OFFSET APPLIED IN RESPONSE TO PREDETERMINED CONDITIONS

TECHNICAL FIELD

[0001] This disclosure relates generally to equipment utilized and operations performed in conjunction with a subterranean well and, in one example described below, more particularly provides for pressure control in drilling operations, with an offset being applied to a pressure setpoint in response to certain predetermined conditions.

BACKGROUND

[0002] It is known to control pressure in a wellbore by controlling a level of pressure applied to the wellbore at or near the surface. This applied pressure can be from one or more of a variety of sources, such as, backpressure applied by a choke in a mud return line, pressure applied by a dedicated backpressure pump, and/or pressure diverted from a standpipe line to the mud return line.

[0003] Therefore, it will be appreciated that improvements are continually needed in the art of controlling pressure in drilling operations.

BRIEF DESCRIPTION OF THE DRAWINGS

[0004] FIG. **1** is a representative partially cross-sectional view of a well drilling system and associated method which can embody principles of this disclosure.

[0005] FIG. **2** is a representative schematic view of another example of the well drilling system and method.

[0006] FIG. **3** is a representative schematic view of a pressure and flow control system which may be used with the system and method of FIGS. **1** & **2**.

[0007] FIG. **4** is a representative flowchart for am example method of controlling pressure in a wellbore, which method can embody principles of this disclosure.

[0008] FIGS. **5**A & B are a representative flowchart for another example of the wellbore pressure control method.

DETAILED DESCRIPTION

[0009] Representatively illustrated in FIG. **1** is a well drilling system **10** and associated method which can embody principles of this disclosure. However, it should be clearly understood that the system **10** and method are merely one example of an application of the principles of this disclosure in practice, and a wide variety of other examples are possible. Therefore, the scope of this disclosure is not limited at all to the details of the system **10** and method described herein and/or depicted in the drawings.

[0010] In the FIG. **1** example, 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, is circulated downward through the drill string **16**, out the drill bit **14** and upward through an annulus **20** formed between the drill string and the wellbore **12**, in order to cool the drill bit, lubricate the drill string, remove cuttings and provide a measure of wellbore pressure control. A non-return valve **21** (typically a flapper-type check valve) prevents flow of the drilling fluid **18** upward through the drill string **16** (e.g., when connections are being made in the drill string).

[0011] Control of wellbore pressure is very important in managed pressure drilling, and in other types of drilling operations. Preferably, the wellbore pressure is precisely controlled to prevent excessive loss of fluid into the earth formation surrounding the wellbore **12**, undesired fracturing of the formation, undesired influx of formation fluids into the wellbore, etc.

[0012] In typical managed pressure drilling, it is desired to maintain the wellbore pressure just slightly greater than a pore pressure of the formation penetrated by the wellbore, without exceeding a fracture pressure of the formation. This technique is especially useful in situations where the margin between pore pressure and fracture pressure is relatively small.

[0013] In typical underbalanced drilling, it is desired to maintain the wellbore pressure somewhat less than the pore pressure, thereby obtaining a controlled influx of fluid from the formation. In typical overbalanced drilling, it is desired to maintain the wellbore pressure somewhat greater than the pore pressure, thereby preventing (or at least mitigating) influx of fluid from the formation.

[0014] 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.

[0015] In the system **10**, additional control over the wellbore pressure is obtained by closing off the annulus **20** (e.g., isolating it from communication with the atmosphere and enabling the annulus to be pressurized at or near the surface) using a rotating control device **22** (RCD). The RCD **22** seals about the drill string **16** above a wellhead **24**. Although not shown in FIG. **1**, the drill string **16** would extend upwardly through the RCD **22** for connection to, for example, a rotary table (not shown), a standpipe line **26**, kelly (not shown), a top drive and/or other conventional drilling equipment.

[0016] 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 mud return lines **30**, **73** to a choke manifold **32**, which includes redundant chokes **34** (only one of which might be used at a time). Backpressure is applied to the annulus **20** by variably restricting flow of the fluid **18** through the operative choke(s) **34**.

[0017] The greater the restriction to flow through the choke **34**, the greater the backpressure applied to the annulus **20**. Thus, downhole pressure (e.g., pressure at the bottom of the wellbore **12**, pressure at a downhole casing shoe, pressure at a particular formation or zone, etc.) can be conveniently regulated by varying the backpressure applied to the annulus **20**. A hydraulics model can be used, as described more fully below, to determine a pressure applied to the annulus **20** at or near the surface which will result in a desired downhole 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 downhole pressure.

[0018] Pressure applied to 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 blowout preventer (BOP) stack **42**. Pressure sensor **38** senses pressure in the wellhead below the BOP stack **42**. Pressure sensor **40** senses pressure in the mud return lines **30**, **73** upstream of the choke manifold **32**.

[0019] Another pressure sensor **44** senses pressure in the 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**, **64**, **66**.

[0020] Not all of these sensors are necessary. For example, the system **10** could include only two of the three flowmeters **62**, **64**, **66**. However, input from all available sensors can be useful to the hydraulics model in determining what the pressure applied to the annulus **20** should be during the drilling operation.

[0021] Other sensor types may be used, if desired. For example, it is not necessary for the flowmeter **58** to be a Coriolis flowmeter, since a turbine flowmeter, acoustic flowmeter, or another type of flowmeter could be used instead.

[0022] In addition, the drill string **16** may include its own sensors **60**, for example, to directly measure downhole 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). These drill string sensor systems generally provide at least pressure measurement, and may also provide temperature measurement, detection of drill string characteristics (such as vibration, weight on bit, stick-slip, etc.), formation characteristics (such as resistivity, density, etc.) and/or other measurements. Various forms of wired or wireless telemetry (acoustic, pressure pulse, electromagnetic, etc.) may be used to transmit the downhole sensor measurements to the surface.

[0023] Additional sensors could be included in the system **10**, if desired. For example, another flowmeter **67** could be used to measure the rate of flow of the fluid **18** exiting the wellhead **24**, another Coriolis flowmeter (not shown) could be interconnected directly upstream or downstream of a rig mud pump **68**, etc.

[0024] Fewer sensors could be included in the system **10**, if desired. For example, the output of the rig mud pump **68** could be determined by counting pump strokes, instead of by using the flowmeter **62** or any other flowmeters.

[0025] Note that the separator **48** could be a 3 or 4 phase separator, or a mud gas separator (sometimes referred to as a "poor boy degasser"). However, the separator **48** is not necessarily used in the system **10**.

[0026] The drilling fluid **18** is pumped through the standpipe line **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 pit **52** and flows it via a standpipe manifold **70** to the standpipe **26**. The fluid **18** then circulates downward through the drill string **16**, upward through the annulus **20**, through the mud return lines **30**, **73**, through the choke manifold **32**, and then via the separator **48** and shaker **50** to the mud pit **52** for conditioning and recirculation.

[0027] 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 downhole pressure, unless the fluid **18** is flowing through the choke. In conventional overbalanced drilling operations, a lack of fluid **18** flow will occur, for example, 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 downhole pressure be regulated solely by the density of the fluid **18**.

[0028] In the system **10**, however, flow of the fluid **18** through the choke **34** can be maintained, even though the fluid does not circulate through the drill string **16** and annulus **20**, while a connection is being made in the drill string. Thus, pressure can still be applied to the annulus **20** by restricting flow of the fluid **18** through the choke **34**, even though a separate backpressure pump may not be used.

[0029] When fluid **18** is not circulating through drill string **16** and annulus **20** (e.g., when a connection is made in the drill string), the fluid is flowed from the pump **68** to the choke manifold **32** via a bypass line **72**, **75**. Thus, the fluid **18** can bypass the standpipe line **26**, drill string **16** and annulus **20**, and can flow directly from the pump **68** to the mud return line **30**, which remains in communication with the annulus **20**. Restriction of this flow by the choke **34** will thereby cause pressure to be applied to the annulus **20** (for example, in typical managed pressure drilling).

[0030] As depicted in FIG. **1**, both of the bypass line **75** and the mud return line **30** are in communication with the annulus **20** via a single line **73**. However, the bypass line **75** and the mud return line **30** could instead be separately connected to the wellhead **24**, for example, using an additional wing valve (e.g., below the RCD **22**), in which case each of the lines **30**, **75** would be directly in communication with the annulus **20**.

[0031] Although this might require some additional piping at the rig site, the effect on the annulus pressure would be essentially the same as connecting the bypass line **75** and the mud return line **30** to the common line **73**. Thus, it should be appreciated that various different configurations of the components of the system **10** may be used, and still remain within the scope of this disclosure.

[0032] Flow of the fluid **18** through the bypass line **72**, **75** is regulated by a choke or other type of flow control device **74**. Line **72** is upstream of the bypass flow control device **74**, and line **75** is downstream of the bypass flow control device.

[0033] Flow of the fluid **18** through the standpipe line **26** is substantially controlled by a valve or other type of flow control device **76**. Since the rate of flow of the fluid **18** through each of the standpipe and bypass lines **26**, **72** is useful in determining how wellbore pressure is affected by these flows, the flowmeters **64**, **66** are depicted in FIG. **1** as being interconnected in these lines.

[0034] However, the rate of flow through the standpipe line **26** could be determined even if only the flowmeters **62**, **64** were used, and the rate of flow through the bypass line **72** could be determined even if only the flowmeters **62**, **66** were used. 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 herein, and the system could instead include additional sensors, different combinations and/or types of sensors, etc.

[0035] In the FIG. **1** example, a bypass flow control device **78** and flow restrictor **80** may be used for filling the standpipe line **26** and drill string **16** after a connection is made in the drill string, and for equalizing pressure between the standpipe line and mud return lines **30**, **73** prior to opening the flow control device **76**. Otherwise, sudden opening of the flow control device **76** prior to the standpipe line **26** and drill string **16** being filled and pressurized with the fluid **18** could cause an undesirable pressure transient in the annulus **20** (e.g., due to flow to the choke manifold **32** temporarily being lost while the standpipe line and drill string fill with fluid, etc.).

[0036] By opening the standpipe bypass flow control device **78** after a connection is made, the fluid **18** is permitted to fill the standpipe line **26** and drill string **16** while a substantial majority of the fluid continues to flow through the bypass line **72**, thereby enabling continued controlled application of pressure to the annulus **20**. After the pressure in the standpipe line **26** has equalized with the pressure in the mud return lines **30**, **73** and bypass line **75**, the flow control device **76** can be opened, and then the flow control device **74** can be closed to slowly divert a greater proportion of the fluid **18** from the bypass line **72** to the standpipe line **26**.

[0037] Before a connection is made in the drill string **16**, a similar process can be performed, except in reverse, to gradually divert flow of the fluid **18** from the standpipe line **26** to the bypass line **72** in preparation for adding more drill pipe to the drill string **16**. That is, the flow control device **74** can be gradually opened to slowly divert a greater proportion of the fluid **18** from the standpipe line **26** to the bypass line **72**, and then the flow control device **76** can be closed.

[0038] Note that the flow control device **78** and flow restrictor **80** could be integrated into a single element (e.g., a flow control device having a flow restriction therein), and the flow control devices **76**, **78** could be integrated into a single flow control device **81** (e.g., a single choke which can gradually open to slowly fill and pressurize the standpipe line **26** and drill string **16** after a drill pipe connection is made, and then open fully to allow maximum flow while drilling).

[0039] However, since typical conventional drilling rigs are equipped with the flow control device **76** in the form of a valve in the standpipe manifold **70**, and use of the standpipe valve is incorporated into usual drilling practices, the individually operable flow control devices **76**, **78** preserve the use of the flow control device **76**. The flow control devices **76**, **78** are at times referred to collectively below as though they are the single flow control device **81**, but it should be understood that the flow control device **81** can include the individual flow control devices **76**, **78**.

[0040] Another example is representatively illustrated in FIG. **2**. In this example, the flow control device **76** is connected upstream of the rig's standpipe manifold **70**. This arrangement has certain benefits, such as, no modifications are needed to the rig's standpipe manifold **70** or the line between the manifold and the kelly, the rig's standpipe bleed valve **82** can be used to vent the standpipe **26** as in normal drilling operations (no need to change procedure by the rig's crew), etc.

[0041] The flow control device **76** can be interconnected between the rig pump **68** and the standpipe manifold **70** using, for example, quick connectors **84** (such as, hammer unions, etc.). This will allow the flow control device **76** to be conveniently adapted for interconnection in various rigs' pump lines.

[0042] A specially adapted fully automated flow control device **76** (e.g., controlled automatically by the controller **96** depicted in FIG. **3**) can be used for controlling flow through the standpipe line **26**, instead of using the conventional standpipe valve in a rig's standpipe manifold **70**. The entire flow control device **81** can be customized for use as described herein (e.g., for controlling flow through the standpipe line **26** in conjunction with diversion of fluid **18** between the standpipe line and the bypass line **72** to thereby control pressure in the annulus **20**, etc.), rather than for conventional drilling purposes.

[0043] In the FIG. **2** example, a remotely controllable valve or other flow control device **160** is optionally used to divert flow of the fluid **18** from the standpipe line **26** to the mud return line **30** downstream of the choke manifold **32**, in order to transmit signals, data, commands, etc. to downhole tools (such as the FIG. **1** bottom hole assembly including the sensors **60**, other equipment, including mud motors, deflection devices, steering controls, etc.). The device **160** is controlled by a telemetry controller **162**, which can encode information as a sequence of flow diversions detectable by the downhole tools (e.g., a certain decrease in flow through a downhole tool will result from a corresponding diversion of flow by the device **160** from the standpipe line **26** to the mud return line **30**).

[0044] A suitable telemetry controller and a suitable remotely operable flow control device are provided in the GEO-SPAN™ system marketed by Halliburton Energy Services, Inc. The telemetry controller **162** can be connected to the INSITE™ system or other acquisition and control interface **94** in the control system **90**. However, other types of telemetry controllers and flow control devices may be used in keeping with the scope of this disclosure.

[0045] Note that each of the flow control devices **74**, **76**, **78** and chokes **34** are preferably remotely and automatically controllable to maintain a desired downhole pressure by maintaining a desired annulus pressure at or near the surface. However, any one or more of these flow control devices **74**, **76**, **78** and chokes **34** could be manually controlled, in keeping with the scope of this disclosure.

[0046] A pressure and flow control system **90** which may be used in conjunction with the system **10** and associated methods of FIGS. **1** & **2** is representatively illustrated in FIG. **3**. The control system **90** is preferably fully automated, although some human intervention may be used, for example, to safeguard against improper operation, initiate certain routines, update parameters, etc.

[0047] The control system **90** includes a hydraulics model **92**, a data acquisition and control interface **94** and a controller **96** (such as a programmable logic controller or PLC, a suitably programmed computer, etc.). Although these elements **92**, **94**, **96** are depicted separately in FIG. **3**, any or all of them could be combined into a single element, or the functions of the elements could be separated into additional elements, other additional elements and/or functions could be provided, etc.

[0048] The hydraulics model **92** is used in the control system **90** to determine a desired annulus pressure at or near the surface to achieve a desired downhole pressure. Data such as well geometry, fluid properties and offset well information (such as geothermal gradient and pore pressure gradient, etc.) are utilized by the hydraulics model **92** in making this determination, as well as real-time sensor data acquired by the data acquisition and control interface **94**.

[0049] Thus, there is a continual two-way transfer of data and information between the hydraulics model **92** and the data acquisition and control interface **94**. It is important to appreciate that the data acquisition and control interface **94** operates to maintain a substantially continuous flow of real-time data from the sensors **44**, **54**, **66**, **62**, **64**, **60**, **58**, **46**, **36**, **38**, **40**, **56**, **67** to the hydraulics model **92**, so that the hydraulics model has the information they need to adapt to changing circumstances and to update the desired annulus pressure, and the hydraulics model operates to supply the data acquisition and control interface substantially continuously with a value for the desired annulus pressure.

[0050] A suitable hydraulics model for use as the hydraulics model **92** in the control system **90** is REAL TIME HYDRAULICS™ or GB SETPOINT™ marketed by Halliburton Energy Services, Inc. of Houston, Tex. USA. Another suitable hydraulics model is provided under the trade name IRIS™, and yet another is available from SINTEF of Trondheim, Norway. Any suitable hydraulics model may be used in the control system **90** in keeping with the principles of this disclosure.

[0051] A suitable data acquisition and control interface for use as the data acquisition and control interface **94** in the control system **90** are SENTRY™ and INSITE™ marketed by Halliburton Energy Services, Inc. Any suitable data acquisition and control interface may be used in the control system **90** in keeping with the principles of this disclosure.

[0052] The controller **96** operates to maintain a desired setpoint annulus pressure by controlling operation of the mud return choke **34** and other devices. For example, the controller **96** may also be used to control operation of the standpipe flow control devices **76**, **78** and the bypass flow control device **74**. The controller **96** can, thus, be used to automate the processes of diverting flow of the fluid **18** from the standpipe line **26** to the bypass line **72** prior to making a connection in the drill string **16**, then diverting flow from the bypass line to the standpipe line after the connection is made, and then resuming normal circulation of the fluid **18** for drilling. Again, no human intervention may be required in these automated processes, although human intervention may be used if desired, for example, to initiate each process in turn, to manually operate a component of the system, etc.

[0053] Data validation and prediction techniques may be used in the system **90** to guard against erroneous data being used, to ensure that determined values are in line with predicted values, etc. Suitable data validation and prediction techniques are described in International Application No. PCT/US11/59743, although other techniques may be used, if desired.

[0054] In the past, when an updated desired annulus pressure was transmitted from the data acquisition and control interface **94** to the controller **96**, the controller used the desired annulus pressure as a setpoint and controlled operation of the choke **34** in a manner (e.g., increasing or decreasing flow resistance through the choke as needed) to maintain the setpoint pressure in the annulus **20**. The choke **34** was closed more to increase flow resistance, or opened more to decrease flow resistance.

[0055] Maintenance of the setpoint pressure was accomplished by comparing the setpoint pressure to a measured annulus pressure (such as the pressure sensed by any of the sensors **36**, **38**, **40**), and decreasing flow resistance through the choke **34** if the measured pressure is greater than the setpoint pressure, and increasing flow resistance through the choke if the measured pressure is less than the setpoint pressure. Unfortunately, the adjustment of the choke was typically determined by a proportional integral derivative (PID) controller, and so (depending on the coefficients input to the PID controller) the choke could easily be over- or under-adjusted, or it could take an extended length of time to progress through a number of increments needed to finally position the choke where it should be positioned to maintain the desired annulus pressure.

[0056] One reason for this situation was that the coefficients used in the PID controller were the same throughout the drilling operation, and were selected for use in normal, relatively "steady state" drilling conditions. These same coefficients were not ideal for use when conditions were rapidly changing, such as, when a sudden change in pressure or flow rate was experienced.

[0057] However, in an example of a method described more fully below, such rapidly changing drilling conditions can be more quickly responded to by adding an offset to the pressure setpoint. Adding the offset to the pressure setpoint will result in the choke **34** more rapidly being adjusted to a position appropriate for controlling the changed drilling conditions. When relatively steady state conditions have resumed, the offset can be removed, so that the controller **96** will adjust the choke **34** to maintain the desired pressure setpoint in the well.

[0058] Referring now to FIG. **4**, a method **100** of controlling pressure in a wellbore is representatively illustrated in simplified flowchart form. The method **100** may be used with the system **10** described above, or it may be used with other systems.

[0059] In an initial step **102** of the method **100**, a desired setpoint pressure is determined. In the system **10**, the setpoint pressure corresponds to a pressure in the annulus **20** at or near the wellhead **24**. The pressure may be measured at any point upstream of the choke manifold **32**.

[0060] However, in other examples, the pressure setpoint could be for a location other than at the wellhead **24**. For example, the pressure setpoint could be for a downhole location (such as, at a casing shoe, at a sensitive formation, at a bottom of the wellbore **12**, etc.). In that case, a surface or downhole actual pressure measurement may be used for comparison to the pressure setpoint by the controller **96**.

[0061] In step **104**, an actual well pressure is measured. As discussed above, the pressure measurement can be made at any well location. For example, surface pressure sensors **36**, **38**, **40** or downhole sensors **60** (or subsea sensors) may be used for the pressure measurement.

[0062] In step **106**, the actual well pressure deviates from the desired pressure setpoint. In the system **10**, the comparison between the actual and desired well pressures is performed by the controller **96**.

[0063] In relatively steady state drilling operations, it is expected that some deviation between the actual and desired well pressures will occur, and the choke **34** is automatically adjusted by the controller **96** as needed to minimize (or, ideally, to eliminate) this deviation. However, when a large deviation occurs, the method **100** provides an added "boost" to the pressure setpoint (in a direction in which the actual pressure needs to change in order to move toward the desired pressure), so that the controller **96** will more rapidly adjust the choke **34** to a position in which the actual pressure will be at or near the desired pressure.

[0064] In step **108**, an offset is added to the desired pressure setpoint, if a difference between the actual and desired pressures is more than a predetermined amount. The predetermined amount is chosen so that, during relatively steady state drilling operations, the offset will not be added to the pressure setpoint. The offset is only added if the difference between the actual and desired pressures is sufficiently large.

[0065] In step **110**, the controller **96** adjusts the choke **34** as needed to influence the actual pressure toward the pressure setpoint plus the offset added in step **108**. For example, if the actual pressure is sufficiently less than the pressure setpoint, a positive offset could be added to the setpoint, so that the controller **96** operates the choke **34** to initially restrict the flow of the fluid **18** from the annulus **20** more than it would if only the pressure setpoint were used by the controller to control operation of the choke. Conversely, if the actual pressure is sufficiently greater than the pressure setpoint, a negative offset could be added to the setpoint, so that the controller **96** operates the choke **34** to initially restrict the flow of the fluid

18 from the annulus 20 less than it would if only the pressure setpoint were used by the controller to control operation of the choke.

[0066] In step 112, the offset is no longer used when the relatively steady state drilling operations resume. If the large deviation which triggered use of the offset is not present, then the offset is removed, so that the controller 96 again operates the choke 34 to maintain the actual pressure at the desired pressure setpoint (without the offset).

[0067] Referring additionally now to FIGS. 5A & B, a more detailed example of the method 100 is representatively illustrated in flowchart form. The FIGS. 5A & B example is merely one application of the principles of this disclosure to a particular drilling situation, but a wide variety of other drilling situations can benefit from this disclosure's principles, and so it should be clearly understood that the scope of this disclosure is not limited at all to any of the details of the system 10 or method 100 depicted in the drawings or described herein.

[0068] The FIGS. 5A & B flowchart is for a routine named "Lead Chokes" to indicate its use in more rapidly advancing the choke(s) 34 toward their appropriate position for maintaining the actual pressure at the desired pressure setpoint. The drilling situation addressed by the routine is one in which a sudden decrease in flow through the choke 34 causes a sudden large drop in pressure upstream of the choke. Such a situation could occur, for example, if the flow rate from the mud pump 68 suddenly decreases, if another flow control device malfunctions or is improperly operated, a large fluid loss is experienced downhole, etc.

[0069] Variables used in the Lead Chokes routine are as follows:

[0070] WHP—actual measured pressure in the annulus 20 at or near the wellhead 24, upstream of the choke 34;

[0071] WHP_Target—a desired pressure setpoint output by the hydraulics model 92;

[0072] CD_Hydrostatic—hydrostatic pressure at a control depth along the wellbore 12 (a depth at which it is desired to maintain a desired pressure);

[0073] CD_Target—a desired pressure (hydrostatic plus friction pressure, if any) at the control depth;

[0074] TurnOffLeadChokesWithin—a deviation between the actual pressure and the desired pressure setpoint, below which no offset is added to the desired pressure setpoint;

[0075] Pumps_Down_Offset—an offset chosen specifically for a drilling situation in which the flow rate from the mud pump 68 suddenly decreases;

[0076] Injection_Flow_Rate—the flow rate of the fluid 18 into the drill string 16;

[0077] Delta_Flow—a change in injection flow rate;

[0078] Delta_Time—a time difference between the current injection flow rate and the previous injection flow rate;

[0079] Rate_Change—the change in injection flow rate divided by the time difference;

[0080] FlowRateChangeThreshold—a change in flow rate per unit time, above which the addition of an offset is indicated;

[0081] LeadChokesStatus—indicates whether the offset is to be added to the desired pressure setpoint;

[0082] LeadChokesOffset—the offset applied to the desired pressure setpoint as a result of the Lead Chokes routine;

[0083] CurrentMaxFlowRateChange—the maximum change in flow rate as of running the routine;

[0084] LastMaxFlowRateChange—a previous maximum change in flow rate;

[0085] Previous_Flow—a previous flow rate used in the routine;

[0086] Previous_Flow_Timestamp—a time at which the previous flow rate was recorded;

[0087] PreviousLeadChokesOffset—a previous offset applied to the desired pressure setpoint;

[0088] PreviousLeadChokesStatus—a previous status of whether the offset was added to the desired pressure setpoint.

[0089] It will be appreciated by those skilled in the art that the addition of the offset in the Lead Chokes routine depicted in FIGS. 5A & B is "triggered" when the rate of change of the injection flow rate (Rate_Change) is greater than or equal to a predetermined level (FlowRateChangeThreshold), and the actual measured pressure (WHP) is less than a desired pressure setpoint (WHP_Target) by a predetermined amount (TurnOffLeadChokesWithin). If these conditions (and others) are satisfied, then an offset (LeadChokesOffset) is added to the desired pressure setpoint.

[0090] The offset (LeadChokesOffset) can be the preselected offset (Pumps_Down_Offset) for this particular drilling situation. Alternatively, if the pressure setpoint plus the offset would be greater than the desired pressure at the control depth (CD_Target) minus the hydrostatic pressure at that depth (CD_Hydrostatic), then the offset can be reduced to the difference between the desired pressure at the control depth minus the hydrostatic pressure at that depth. This is to mitigate the possibility that the choke 34 could restrict flow too much with the addition of the offset to the pressure setpoint, so that excess pressure is applied at the control depth.

[0091] In other examples, different drilling operation situations could be addressed. For example, separate routines could be provided for addressing fluid influxes, fluid losses, making connections in the drill string 16, or any other situation. Thus, the scope of this disclosure is not limited to use of the offset only when a sudden flow rate decrease is experienced.

[0092] It may now be fully appreciated that the above disclosure provides significant advancements to the art of controlling pressure in drilling operations. The method 100 can be used to control the choke 34 as needed to quickly restore a desired wellbore pressure. In an example described above, an offset can be added to a desired wellbore 12 pressure setpoint, so that the choke 34 is more rapidly adjusted as needed to maintain the desired pressure in the wellbore.

[0093] A method 100 of controlling pressure in a wellbore 12 in a well drilling operation is described above. In one example, the method 100 comprises: determining a desired well pressure setpoint; adding an offset to the well pressure setpoint in response to an actual well pressure deviating from the well pressure setpoint by a predetermined amount; and adjusting a flow control device (e.g., the choke 34), thereby influencing the actual well pressure toward the well pressure setpoint plus the offset.

[0094] The desired well pressure setpoint can be output by a hydraulics model 92.

[0095] The offset adding may also be performed in response to a predetermined level of change in flow. The predetermined level of change in flow may comprise a decrease in flow through the flow control device (e.g., the choke 34).

[0096] The method can also include removing the offset in response to the actual well pressure deviating from the well pressure setpoint by less than the predetermined amount.

[0097] The flow control device may comprise a choke **34** which restricts flow of fluid from the wellbore **12**.

[0098] The method can also include controlling the flow control device, thereby influencing the actual well pressure toward the well pressure setpoint without the offset, prior to adding the offset to the setpoint.

[0099] Also described above is a well system **10**. In one example, the well system **10** can include a flow control device which variably restricts flow from a wellbore **12**, and a control system **90** which determines a desired well pressure setpoint, compares the well pressure setpoint to an actual well pressure, and adds an offset to the desired well pressure setpoint in response to a predetermined amount of deviation between the well pressure setpoint and the actual well pressure. The control system **90** adjusts the flow control device, and thereby influences the actual well pressure toward the well pressure setpoint plus the offset.

[0100] Another example of the method **100** of controlling pressure in a wellbore **12** in a well drilling operation can comprise: operating a flow control device, thereby influencing an actual well pressure toward a desired well pressure setpoint; then adding an offset to the well pressure setpoint in response to an actual well pressure deviating from the well pressure setpoint by a predetermined amount; and then adjusting the flow control device, thereby influencing the actual well pressure toward the well pressure setpoint plus the offset.

[0101] Although various examples have been described above, with each example having certain features, it should be understood that it is not necessary for a particular feature of one example to be used exclusively with that example. Instead, any of the features described above and/or depicted in the drawings can be combined with any of the examples, in addition to or in substitution for any of the other features of those examples. One example's features are not mutually exclusive to another example's features. Instead, the scope of this disclosure encompasses any combination of any of the features.

[0102] Although each example described above includes a certain combination of features, it should be understood that it is not necessary for all features of an example to be used. Instead, any of the features described above can be used, without any other particular feature or features also being used.

[0103] It should be understood that the various embodiments 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 embodiments are described merely as examples of useful applications of the principles of the disclosure, which is not limited to any specific details of these embodiments.

[0104] In the above description of the representative examples, directional terms (such as "above," "below," "upper," "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.

[0105] The terms "including," "includes," "comprising," "comprises," and similar terms are used in a non-limiting sense in this specification. For example, if a system, method, apparatus, device, etc., is described as "including" a certain feature or element, the system, method, apparatus, device, etc., can include that feature or element, and can also include other features or elements. Similarly, the term "comprises" is considered to mean "comprises, but is not limited to."

[0106] Of course, a person skilled in the art would, upon a 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 by the principles of this disclosure. For example, structures disclosed as being separately formed can, in other examples, be integrally formed and vice versa. 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.

What is claimed is:

1. A method of controlling pressure in a wellbore in a well drilling operation, the method comprising:
- determining a desired well pressure setpoint;
- adding an offset to the well pressure setpoint in response to an actual well pressure deviating from the well pressure setpoint by a predetermined amount; and
- adjusting a flow control device, thereby influencing the actual well pressure toward the well pressure setpoint plus the offset.

2. The method of claim **1**, wherein the desired well pressure setpoint is output by a hydraulics model.

3. The method of claim **1**, wherein the adding is performed further in response to a predetermined level of change in flow.

4. The method of claim **3**, wherein the predetermined level of change in flow comprises a decrease in flow through the flow control device.

5. The method of claim **1**, further comprising removing the offset in response to the actual well pressure deviating from the well pressure setpoint by less than the predetermined amount.

6. The method of claim **1**, wherein the flow control device comprises a choke which restricts flow of fluid from the wellbore.

7. The method of claim **1**, further comprising controlling the flow control device, thereby influencing the actual well pressure toward the well pressure setpoint without the offset, prior to the adding.

8. A well system, comprising:
- a flow control device which variably restricts flow from a wellbore; and
- a control system which determines a desired well pressure setpoint, compares the well pressure setpoint to an actual well pressure, and adds an offset to the desired well pressure setpoint in response to a predetermined amount of deviation between the well pressure setpoint and the actual well pressure, whereby the control system adjusts the flow control device, and thereby influences the actual well pressure toward the well pressure setpoint plus the offset.

9. The system of claim **8**, wherein the control system comprises a hydraulics model, and wherein the well pressure setpoint is output by the hydraulics model.

10. The system of claim **8**, wherein the control system adds the offset to the well pressure setpoint further in response to a predetermined level of change in flow.

11. The system of claim **10**, wherein the predetermined level of change in flow comprises a decrease in flow through the flow control device.

12. The system of claim **8**, wherein the control system removes the offset in response to the deviation between the actual well pressure and the well pressure setpoint being less than the predetermined amount.

13. The system of claim **8**, wherein the flow control device comprises an automatically adjustable choke.

14. The system of claim **8**, wherein the control system controls the flow control device, and thereby influences the actual well pressure toward the well pressure setpoint without the offset, when the deviation between the well pressure setpoint and the actual well pressure is less than the predetermined amount.

15. A method of controlling pressure in a wellbore in a well drilling operation, the method comprising:

operating a flow control device, thereby influencing an actual well pressure toward a desired well pressure setpoint;

then adding an offset to the well pressure setpoint in response to an actual well pressure deviating from the well pressure setpoint by a predetermined amount; and

then adjusting the flow control device, thereby influencing the actual well pressure toward the well pressure setpoint plus the offset.

16. The method of claim **15**, wherein the desired well pressure setpoint is output by a hydraulics model.

17. The method of claim **15**, wherein the adding is performed further in response to a predetermined level of change in flow.

18. The method of claim **17**, wherein the predetermined level of change in flow comprises a decrease in flow through the flow control device.

19. The method of claim **15**, further comprising, after the adjusting, removing the offset in response to the actual well pressure deviating from the well pressure setpoint by less than the predetermined amount.

20. The method of claim **15**, wherein the flow control device comprises a choke which restricts flow of fluid from the wellbore.

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