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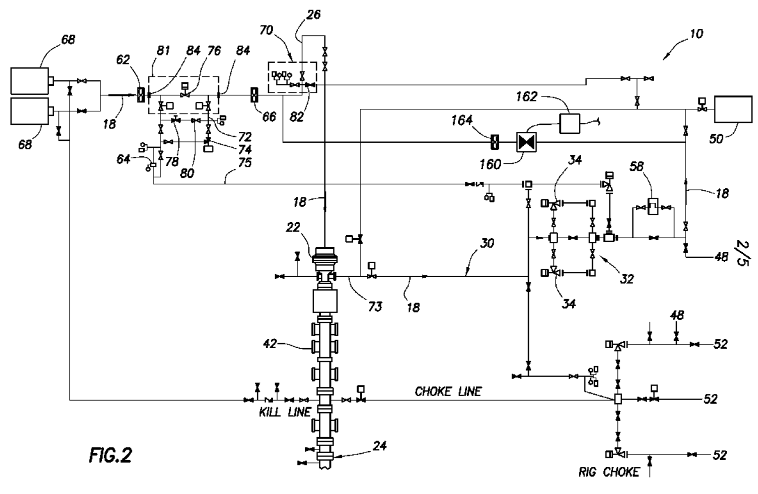

FIG.2

(57) Abstract: A control system for drilling a subterranean well can include multiple concurrently running hydraulics models, each of the hydraulics models outputting a pressure setpoint, in real time during a drilling operation. A method of controlling a drilling operation can comprise concurrently running multiple hydraulics models during the drilling operation, and switching between outputs of the multiple hydraulics models to control the drilling operation, the switching being performed during the drilling operation. Another method of controlling a drilling operation can include controlling operation of at least one flow control device, thereby maintaining a pressure at a pressure setpoint, and selecting the pressure setpoint from among outputs of multiple concurrently running hydraulics models.

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DRILLING OPERATION CONTROL USING MULTIPLE CONCURRENT HYDRAULICS MODELS

TECHNICAL FIELD

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 wellbore pressure control using multiple concurrently-running hydraulics models.

BACKGROUND

A hydraulics model can be used to control a drilling operation, for example, in managed pressure, underbalanced, overbalanced or optimized pressure drilling. Typically, an objective is to maintain wellbore pressure at a desired value during the drilling operation. Unfortunately, such hydraulics models are unlikely to be equally adept at outputting setpoints for controlling the drilling operation in different circumstances (e.g., drilling ahead, taking an influx, fluid loss, etc.).

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

BRIEF DESCRIPTION OF THE DRAWINGS

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

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

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.

FIG. 4 is a representative flowchart for a method of controlling a drilling operation.

FIGS. 5 & 6 are representative flowcharts for further examples of the drilling operation control method.

DETAILED DESCRIPTION

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.

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 bottom hole 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).

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.

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.

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.

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.

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, kelley (not shown), a top drive and/or other conventional drilling equipment.

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.

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. Hydraulics models 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.

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.

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.

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 models in determining what the pressure applied to the annulus 20 should be during the drilling operation.

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.

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.

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.

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.

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.

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.

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.

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.

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).

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.

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.

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.

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.

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.

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.).

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.

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.

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).

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.

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 kelley, 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.

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.

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.

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).

A suitable telemetry controller and a suitable remotely operable flow control device are provided in the GEO-SPAN(TM) system marketed by Halliburton Energy Services, Inc. The telemetry controller 162 can be connected to the INSITE(TM) 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.

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.

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.

The control system 90 includes multiple hydraulics models 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.

Three hydraulics models 92 are illustrated in FIG. 3, but any number of hydraulics models may be used. Furthermore, the hydraulics models 92 may be concurrently-running instances of a hydraulics model, instead of separate hydraulics models. As used herein, multiple hydraulics models can refer to both multiple separate hydraulics models and multiple instances of a hydraulics model.

The hydraulics models 92 are used in the control system 90 to determine the 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 models 92 in making this determination, as well as real-time sensor data acquired by the data acquisition and control interface 94.

Thus, there is a continual two-way transfer of data and information between the hydraulics models 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 models 92, so that the hydraulics models have the information they need to adapt to changing circumstances and to update the desired annulus pressure, and the hydraulics models operate to supply the data acquisition and control interface substantially continuously with values for the desired annulus pressure.

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

A suitable data acquisition and control interface for use as the data acquisition and control interface 94 in the control system 90 are SENTRY(TM) and INSITE(TM) 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.

The controller 96 operates to maintain a desired setpoint annulus pressure by controlling operation of the mud return choke 34 and other devices. When an updated desired annulus pressure is transmitted from the data acquisition and control interface 94 to the controller 96, the controller uses the desired annulus pressure as a setpoint and controls 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 can be closed more to increase flow resistance, or opened more to decrease flow resistance.

Maintenance of the setpoint pressure is 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. Of course, if the setpoint and measured pressures are the same, then no adjustment of the choke 34 is required. This process is preferably automated, so that no human intervention is required, although human intervention may be used, if desired.

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.

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.

The hydraulics models 92 are used to generate the desired annulus pressure setpoint, based on different considerations. The hydraulics models 92 can have different sets of data input to them from the data acquisition and control interface 94. The setpoint output by one hydraulics model 92 can be different from the setpoint output by another hydraulics model.

For example, one hydraulics model 92 could model typical drilling ahead in a managed pressure drilling operation. Another hydraulics model 92 could model a drill string 16 connection process, or tripping the drill string into or out of the wellbore 12. Another hydraulics model 92 could model an influx being received into the wellbore 12. Another hydraulics model 92 could model a loss of fluid from the wellbore 12. Another hydraulics model 92 could model multiphase flow in the well. Another hydraulics model 92 could model high or low pressure, or high or low flow, conditions. Another hydraulics model 92 could model an optimized rate of penetration for a drilling operation. Another hydraulics model 92 could model an optimized drill bit 14 life for a drilling operation. Any type, number and combination of hydraulics models 92 may be used, as desired.

When one of these circumstances occurs (e.g., an influx, fluid loss, drill string connection, etc.), a selector 98 can be operated to select which of the annulus pressure setpoints generated by the multiple hydraulics models 92 is output to the controller 96 for controlling operation of the choke 34, bypass choke 74, standpipe valve 76, and/or standpipe flow control 78, etc. The selector 98 is depicted separately in FIG. 3 for clarity, but in actual practice the selector may be part of the data acquisition and control interface 94, or another portion of the system 90.

The selection of which annulus pressure setpoint is used by the controller 96 can be made manually or automatically, and in response to certain considerations. For example, if a particular objective (e.g., optimum rate of penetration, optimum drill bit life, etc.) is desired, then the corresponding hydraulics model 92 setpoint output may be selected manually. In this manner, the selected hydraulics model 92 setpoint output will be used by the controller 96 to control the drilling system 10 in a manner that accomplishes the particular objective.

The selection can be made automatically in other circumstances. For example, if an event detection system detects that an event (such as an influx or fluid loss, etc.) has occurred, or is about to occur, then the corresponding hydraulics model 92 which models such an event can be selected automatically. In this manner, the selected hydraulics model 92 setpoint output will be used by the controller 96 to control the drilling system 10 in a manner that appropriately “handles” the event.

The automatic switching from one hydraulics model 92 to another could be performed only after authorization from an operator, if desired. Suitable event detection systems are described in International Application Nos. PCT/US09/52227 and PCT/US11/42917. Of course, other event detection systems may be used, if desired.

Manual switching from one hydraulics model 92 to another could be done if it appears that one model is more accurately predicting well conditions than another model. For example, one hydraulics model 92 may be predicting wellbore pressure downhole which does not closely match actual measurements made by the downhole sensors 60. In that case, it may be beneficial to switch to another hydraulics model 92 which is more accurately predicting the wellbore pressure downhole.

Referring additionally now to FIG. 4, a method 100 which can embody principles of this disclosure is representatively illustrated in flowchart form. The method 100 may be used with the system 10 described above, or it may be used with other drilling systems.

In the FIG. 4 example, multiple hydraulics models 92 are running concurrently in step 102. The hydraulics models 92 are preferably running concurrently in real time (that is, while the drilling operation is being performed).

As discussed above, the multiple hydraulics models 92 may not be separate hydraulics models, but could be multiple instances of a hydraulics model. It is not necessary that the hydraulics models 92 run simultaneously, but preferably the hydraulics models are running concurrently during the drilling operation.

In step 104, the annulus pressure setpoint output by a first hydraulics model 92 is used by the controller 96 for controlling wellbore pressure during the drilling operation. The setpoint output by the first hydraulics model 92 (and any other hydraulics models) may be subject to the data validation and prediction techniques discussed above. The selection of the first hydraulics model 92 setpoint for controlling the drilling operation could be based on any considerations (e.g., an informed choice, a desired objective, a particular circumstance, a detected event, etc.).

In step 106, the selector 98 is used to select an annulus pressure setpoint output by another hydraulics model 92 for controlling the drilling operation. This switch from the first hydraulics model 92 to a second hydraulics model could be performed manually, completely automatically, or automatically upon human authorization, etc.

In step 108, the annulus pressure setpoint output by the second hydraulics model 92 is used by the controller 96 for controlling wellbore pressure during the drilling operation. The selection of the second hydraulics model 92 setpoint for controlling the drilling operation could be based on any considerations (e.g., an informed choice, a change in desired objective, a particular circumstance, a detected event, etc.).

Thus, in the method 100, a switch is made from the annulus pressure setpoint output by the first hydraulics model 92, to the annulus pressure setpoint output by the second hydraulics model, for input to the controller 96 to control the drilling operation. The switch between the hydraulics models 92 outputs is performed in real time, during the drilling operation.

Representatively illustrated in FIG. 5 is another example of the method 100, in which an additional step 105 is interposed between steps 104 and 106. In step 105, a comparison is made between drilling parameter values predicted by the hydraulics models 92 and actual drilling parameter values measured during the drilling operation.

A particular hydraulics model 92 may, for whatever reason, do a better job of predicting actual drilling parameters (such as downhole pressures, etc.) than others of the hydraulics models. In that case, wellbore pressure may be more accurately controlled using that particular hydraulics model 92.

Thus, the switch between the hydraulics models 92 outputs in step 106 is based on the comparison of predicted to actual drilling parameter values performed in step 105. The switch may be accomplished manually, completely automatically, or automatically upon human authorization, etc.

Representatively illustrated in FIG. 6 is another example of the method 100, in which the step 105 interposed between steps 104 and 106 comprises an event detection. In response to detection of the event, the selector 98 switches to the output of the hydraulics model 92 which models that particular event. Thus, the controller 96 controls the drilling operation based on the annulus pressure setpoint output by the hydraulics model 92 which models a detected event.

As described in the International Application Nos. PCT/US09/52227 and PCT/US11/42917 mentioned above, an event can be a precursor to another event, or can indicate a likelihood that an event is about to occur. In that case, the switching to a corresponding hydraulics model 92 output can prevent the upcoming event from occurring, or at least mitigate its effects on the drilling operation.

When an event is detected, an operator may be presented with an indication or warning of the event, at which point the operator can determine whether to switch to a hydraulics model 92 which models that event (or a predicted event). Alternatively, the switch can be performed automatically, or automatically upon human authorization.

Note that it is not necessary for the multiple hydraulics models 92 to run simultaneously or concurrently. For example, the hydraulics models 92 could be run sequentially (e.g., daisy-chained) to provide the pressure setpoints periodically.

It is also not necessary for the device controlled by the controller 96 to be a flow control device. For example, a backpressure pump or suction pump, or another type of device, could be controlled to maintain the setpoint.

It can now be fully appreciated that the above disclosure provides significant advancements to the art of controlling drilling operations. By concurrently running multiple hydraulics models 92, an operator or automated system can select which of the multiple hydraulics models is appropriate for a given objective, situation, event, etc., occurring during the drilling operation. This enhances the ability of the pressure and flow control system 90 to adapt to changing circumstances.

A control system 90 for drilling a subterranean well is described above. In one example, the control system 90 can include multiple hydraulics models 92, each of the hydraulics models 92 outputting a pressure setpoint, in real time during a drilling operation.

The system 90 can also include a controller 96 and a selector 98. The controller 96 may control operation of at least one device 34, 74, 76, 78, and the selector 98 may select which of the multiple pressure setpoints is input to the controller 96.

The device can comprise a choke 34 which variably restricts flow from a wellbore 12, the device 76 may control flow through a standpipe 26, or the device 74 may control flow between a standpipe 26 and a mud return line 30. Othe types of devices, and other types of flow control devices, may be used.

The multiple hydraulics models 92 may comprise multiple instances of a same hydraulics model.

Also described above is a method 100 of controlling a drilling operation. In one example, the method 100 may comprise running multiple hydraulics models 92 during the drilling operation; and switching between outputs of the multiple hydraulics models 92 to control the drilling operation, the switching being performed during the drilling operation. The hydraulics models may run concurrently.

The method can include controlling operation of at least one device 34, 74, 76, 78, thereby maintaining a pressure at a pressure setpoint output by one of the multiple hydraulics models 92. The device may comprise a flow control device.

The switching step can include switching from a first hydraulics model 92 output to a second hydraulics model 92 output. The switching may be performed in response to a change in an objective of the drilling operation, in response to detection of an event, and/or in response to a comparison between a measured drilling parameter value and the drilling parameter value as predicted by the hydraulics models 92.

The switching can be performed manually or automatically.

Another method 100 of controlling a drilling operation described above can include controlling operation of at least one device 34, 74, 76, 78, thereby maintaining a pressure at a pressure setpoint; and selecting the pressure setpoint from among outputs of multiple hydraulics models 92.

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.

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.

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.

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.

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."

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 control system for drilling a subterranean well, the control system comprising:

multiple hydraulics models, whereby each of the hydraulics models outputs a pressure setpoint, in real time during a drilling operation.

2. The system of claim 1, further comprising a controller and a selector, wherein the controller controls operation of at least one device, and wherein the selector selects which of the multiple pressure setpoints is input to the controller.

3. The system of claim 2, wherein the device comprises a flow control device.

4. The system of claim 3, wherein the flow control device comprises a choke which variably restricts flow from a wellbore.

5. The system of claim 3, wherein the flow control device controls flow through a standpipe.

6. The system of claim 3, wherein the flow control device controls flow between a standpipe and a mud return line.

7. The system of claim 1, wherein the multiple hydraulics models comprise multiple instances of a same hydraulics model.

8. The system of claim 1, wherein the multiple hydraulics models run concurrently.

9. A method of controlling a drilling operation, the method comprising:

running multiple hydraulics models during the drilling operation; and

switching between outputs of the multiple hydraulics models to control the drilling operation, the switching being performed during the drilling operation.

10. The method of claim 9, further comprising controlling operation of at least one device, thereby maintaining a pressure at a pressure setpoint output by one of the multiple concurrently running hydraulics models.

11. The method of claim 10, wherein the device comprises a flow control device.

12. The method of claim 11, wherein the flow control device comprises a choke which variably restricts flow from a wellbore.

13. The method of claim 11, wherein the flow control device controls flow through a standpipe.

14. The method of claim 11, wherein the flow control device controls flow between a standpipe and a mud return line.

15. The method of claim 9, wherein the switching further comprises switching from a first hydraulics model output to a second hydraulics model output.

16. The method of claim 9, wherein the switching is performed in response to a change in an objective of the drilling operation.

17. The method of claim 9, wherein the switching is performed in response to detection of an event.

18. The method of claim 9, wherein the switching is performed in response to a comparison between a measured drilling parameter value and the drilling parameter value as predicted by the hydraulics models.

19. The method of claim 9, wherein the switching is performed manually.

20. The method of claim 9, wherein the switching is performed automatically.

21. The method of claim 9, wherein running the multiple hydraulics models further comprises running the hydraulics models concurrently.

22. A method of controlling a drilling operation, the method comprising:

controlling operation of at least one device, thereby maintaining a pressure at a pressure setpoint; and

selecting the pressure setpoint from among outputs of multiple hydraulics models.

23. The method of claim 22, wherein the selecting further comprises switching from a first hydraulics model output to a second hydraulics model output.

24. The method of claim 23, wherein the switching is performed in response to a change in an objective of the drilling operation.

25. The method of claim 23, wherein the switching is performed in response to detection of an event.

26. The method of claim 23, wherein the switching is performed in response to a comparison between a measured drilling parameter value and the drilling parameter value as predicted by the first and second hydraulics models.

27. The method of claim 22, wherein the selecting is performed manually.

28. The method of claim 22, wherein the selecting is performed automatically.

29. The method of claim 22, wherein the hydraulics models are concurrently running.

30. The method of claim 22, wherein the device comprises a flow control device.

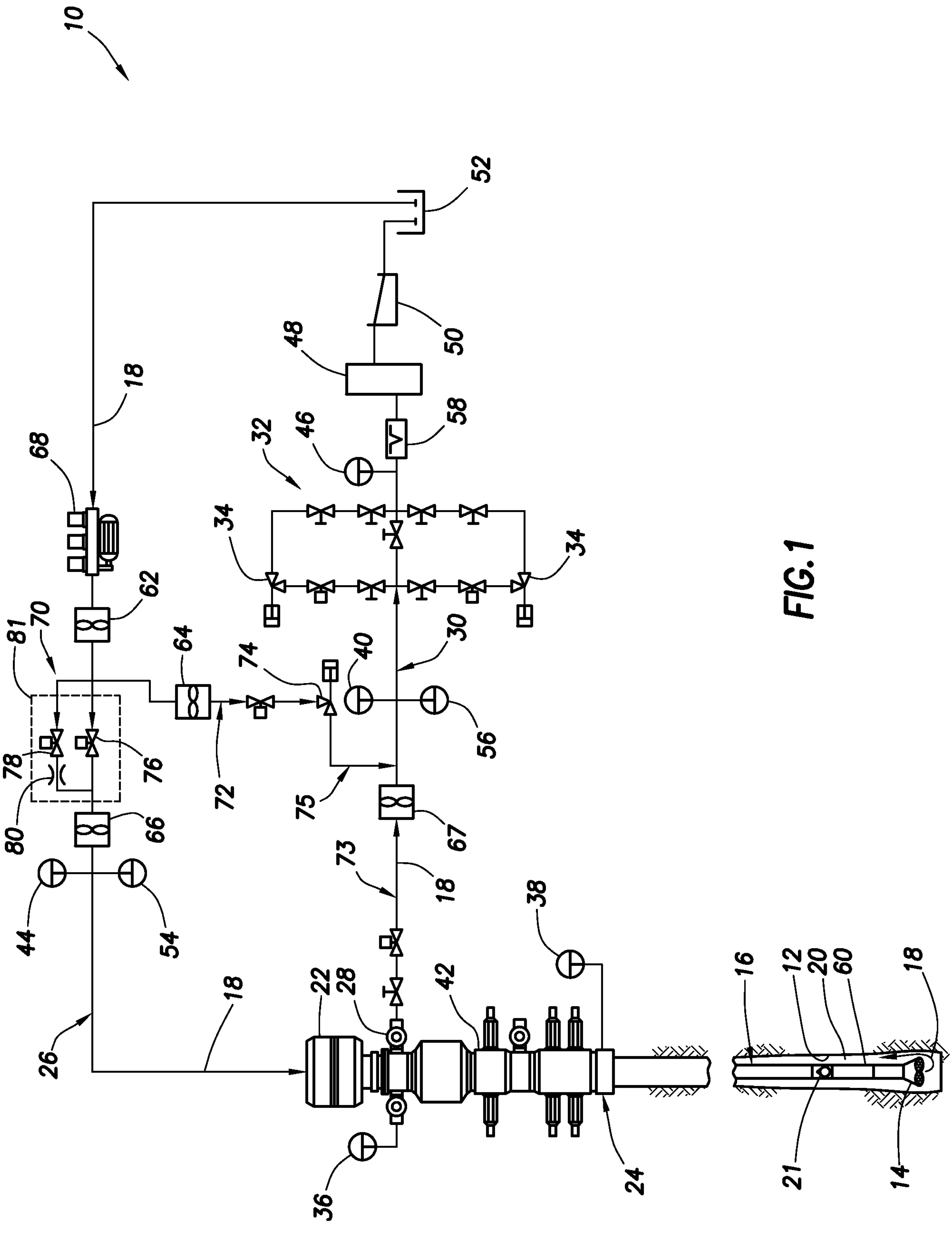
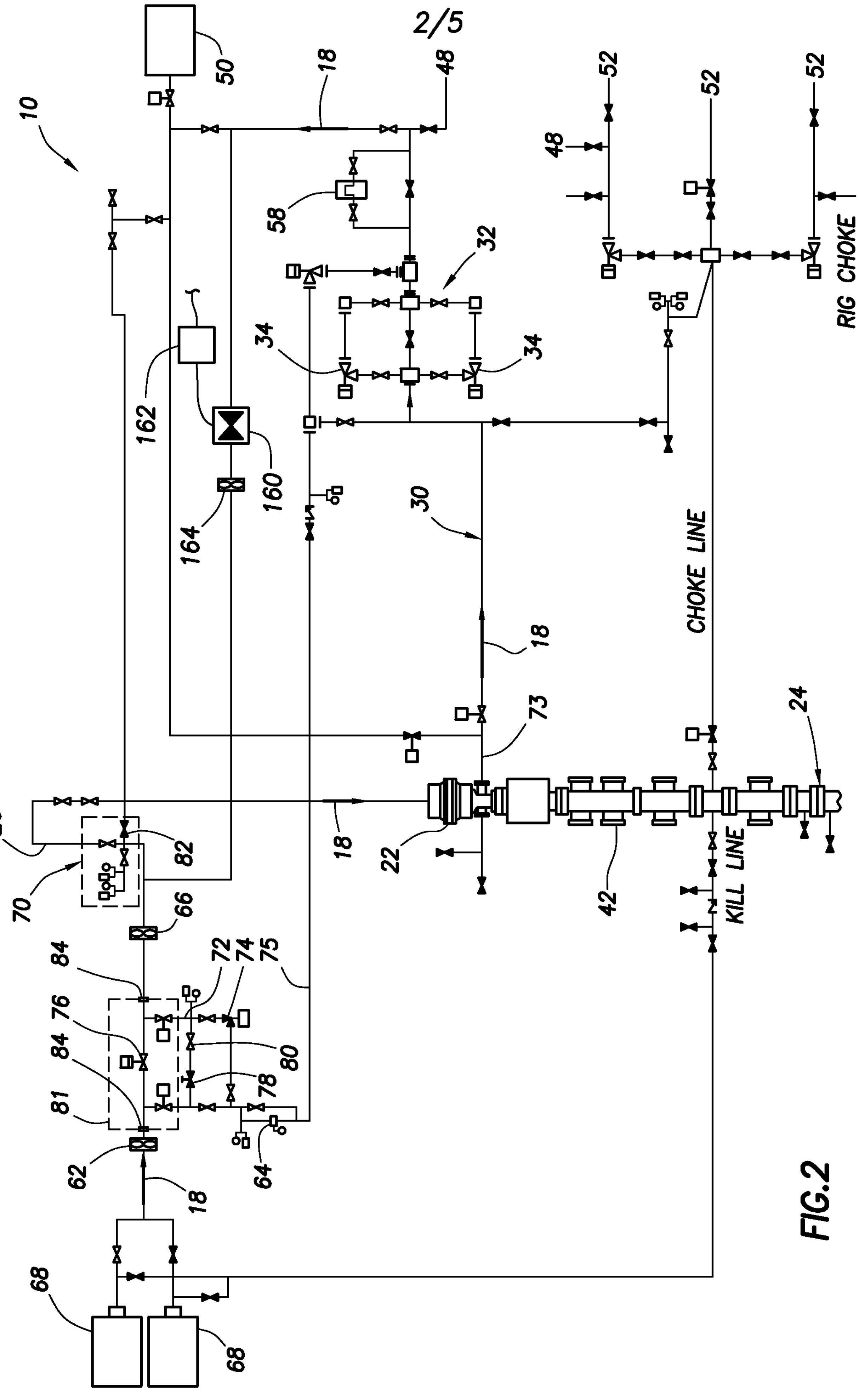


FIG. 1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RIG CHOKE
162
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164
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CHOKE LINE
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24
26
82
18
22
42
KILL LINE
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76
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84
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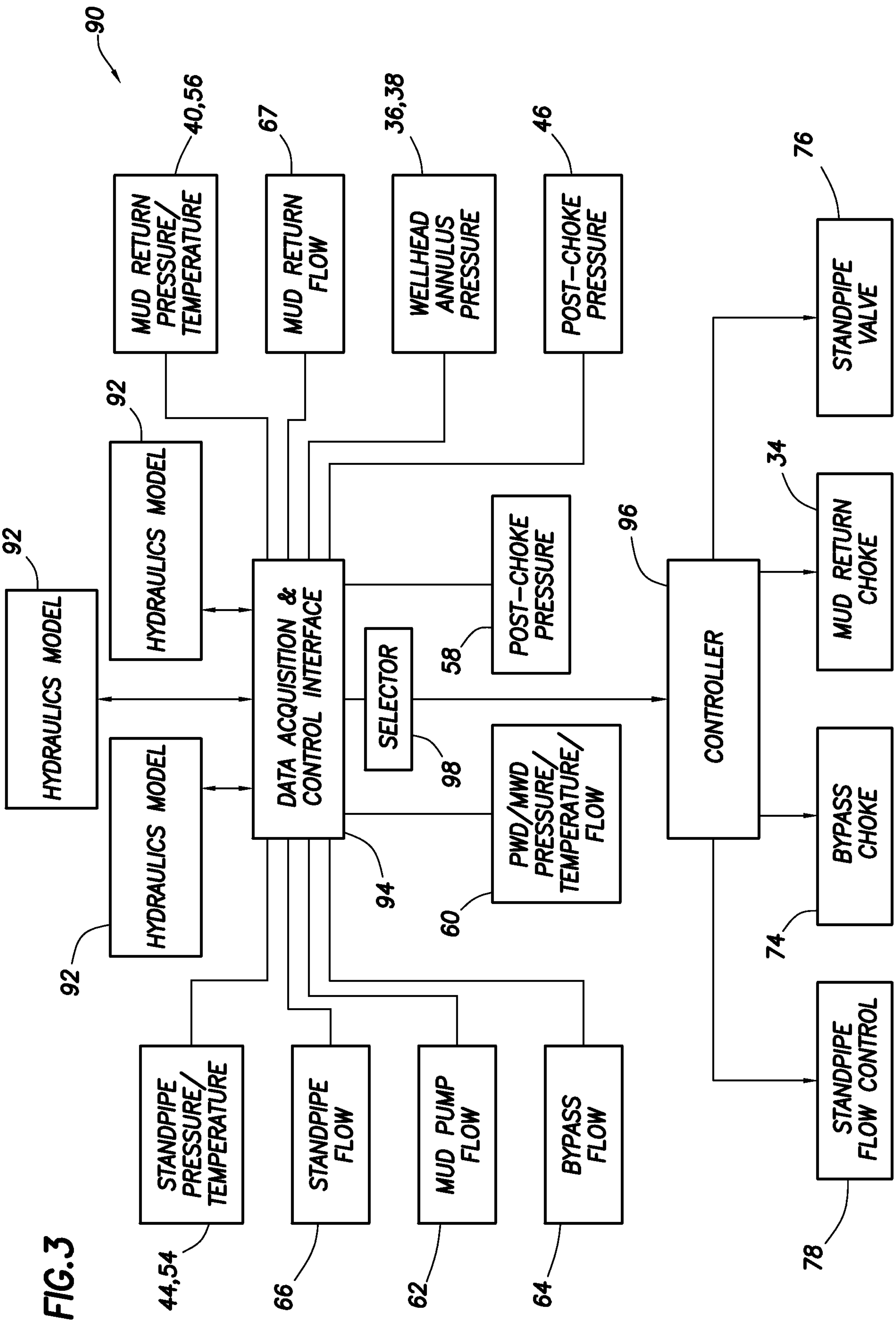
81
62
64
18
68
68

FIG.2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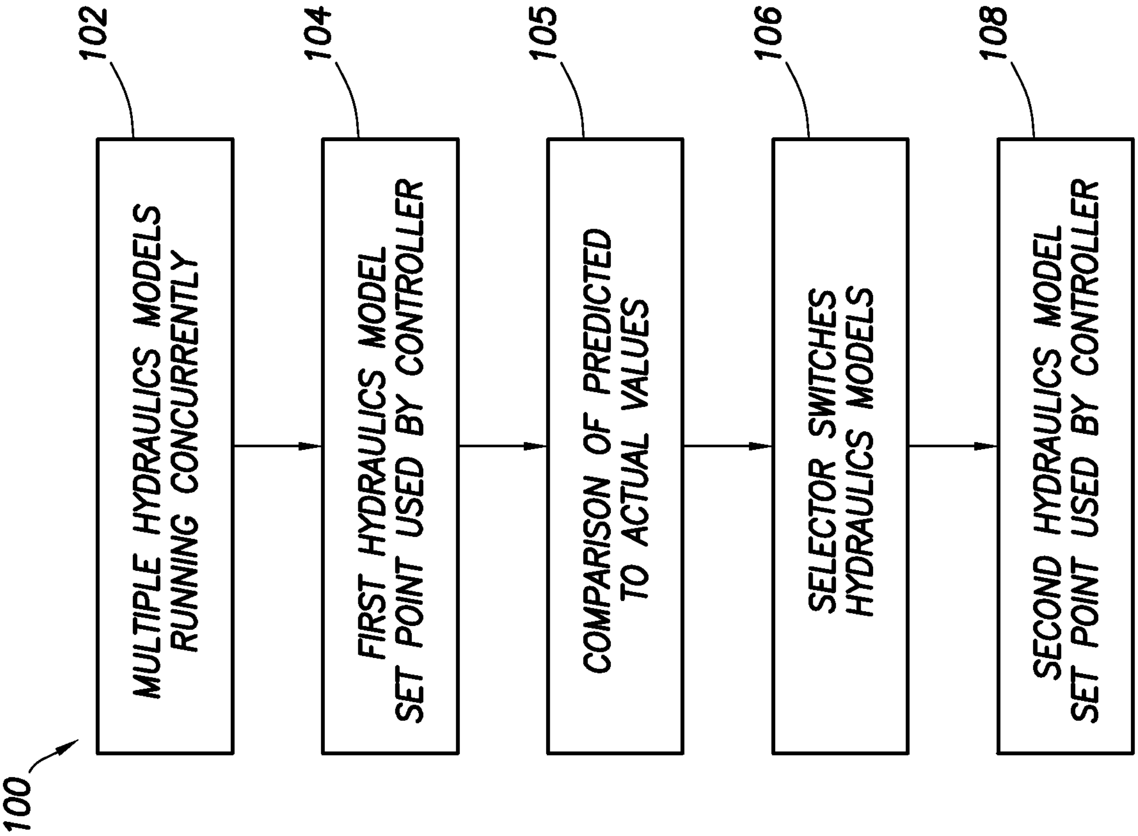
40,56
MUD RETURN FLOW
67
WELLHEAD ANNULUS PRESSURE
36,38
POST-CHOKE PRESSURE
46
STANDPIPE VALVE
76
HYDRAULICS MODEL
92
HYDRAULICS MODEL
92
HYDRAULICS MODEL
92
DATA ACQUISITION & CONTROL INTERFACE
94
POST-CHOKE PRESSURE
58
SELECTOR
98
PWD/MWD PRESSURE/ TEMPERATURE/ FLOW
60
CONTROLLER
96
MUD RETURN CHOKE
34
BYPASS CHOKE
74
STANDPIPE FLOW CONTROL
78
STANDPIPE PRESSURE/ TEMPERATURE
44,54
STANDPIPE FLOW
66
MUD PUMP FLOW
62
BYPASS FLOW
64

FIG.3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102
MULTIPLE HYDRAULICS MODELS RUNNING CONCURRENTLY
104
FIRST HYDRAULICS MODEL SET POINT USED BY CONTROLLER
105
COMPARISON OF PREDICTED TO ACTUAL VALUES
106
SELECTOR SWITCHES HYDRAULICS MODELS
108
SECOND HYDRAULICS MODEL SET POINT USED BY CONTROLLER

FIG.5

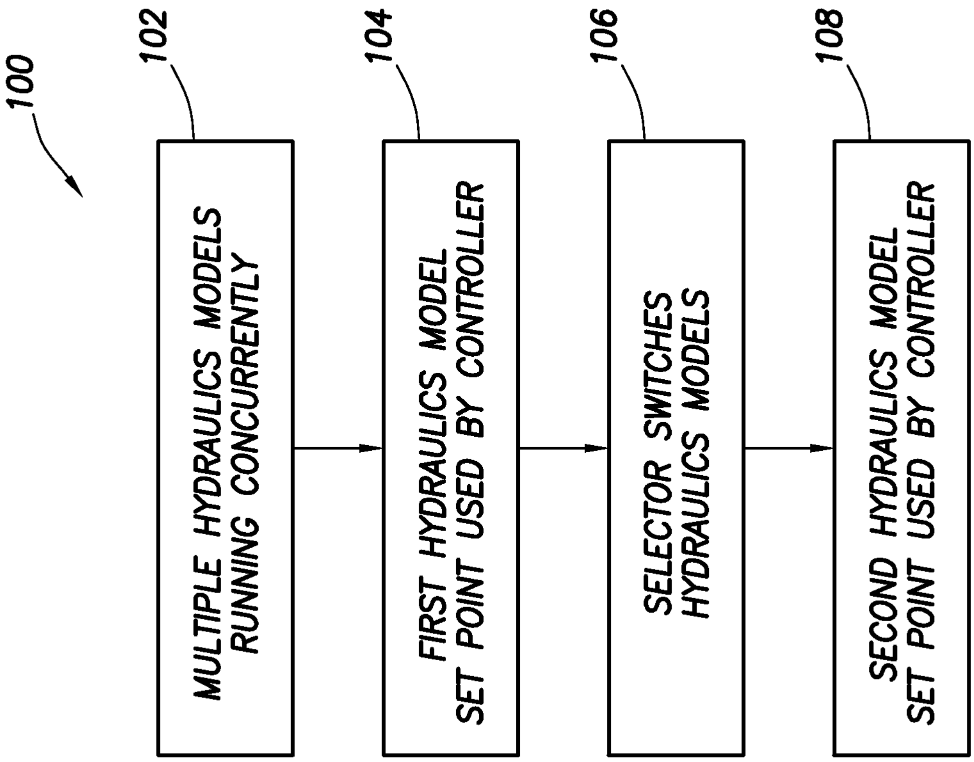
100
102
MULTIPLE HYDRAULICS MODELS RUNNING CONCURRENTLY
104
FIRST HYDRAULICS MODEL SET POINT USED BY CONTROLLER
106
SELECTOR SWITCHES HYDRAULICS MODELS
108
SECOND HYDRAULICS MODEL SET POINT USED BY CONTROLLER

FIG.4

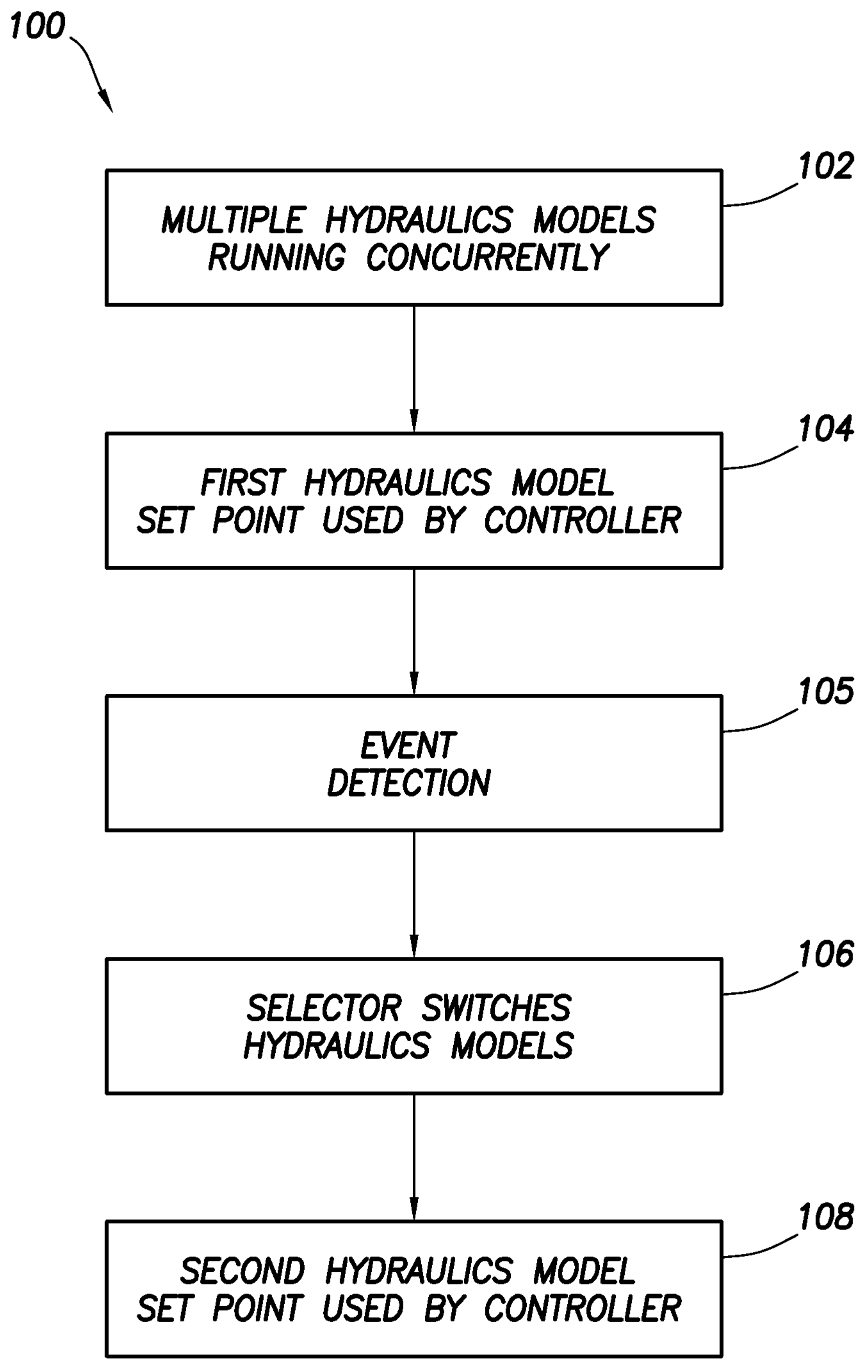
100
MULTIPLE HYDRAULICS MODELS RUNNING CONCURRENTLY
102
FIRST HYDRAULICS MODEL SET POINT USED BY CONTROLLER
104
EVENT DETECTION
105
SELECTOR SWITCHES HYDRAULICS MODELS
106
SECOND HYDRAULICS MODEL SET POINT USED BY CONTROLLER
108

FIG.6

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2012/039586

A. CLASSIFICATION OF SUBJECT MATTER

E21B 44/06(2006.01)i, E21B 4/02(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 44/06; E21B 7/00; G06F 19/00; E21B 44/00; G01N 15/08

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & keywords: wellbore, drilling mud, multiple hydraulics models, pressure control, pressure setpoint and similar terms

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y A	US 2011-0290562 A1 (STANDIFIRD, WILLIAM BRADLEY et al.) 1 December 2011 See paragraphs [0011], [0030]-[0031], [0040], [0054], [0063], [0075] and figures 1, 3.	1-8,22,27-30 9-21,23-26
Y	US 2004-0010373 A1 (SMITS, JAN W. et al.) 15 January 2004 See paragraphs [0020], [0031], [0033], [0037], [0041] - [0043] and figures 2-3.	1-8,22,27-30
A	US 2008-0234939 A1 (FOOT, JOHN et al.) 25 September 2008 See paragraphs [0011], [0017], [0056] and figures 5-6.	1-30
A	US 2002-0108783 A1 (ELKINS, HUBERT L. et al.) 15 August 2002 See paragraphs [0035], [0036] and figure 1.	1-30

☐ Further documents are listed in the continuation of Box C.   ☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
19 FEBRUARY 2013 (19.02.2013)	**20 FEBRUARY 2013 (20.02.2013)**

Name and mailing address of the ISA/KR
Korean Intellectual Property Office
189 Cheongsa-ro, Seo-gu, Daejeon Metropolitan City, 302-701, Republic of Korea
Facsimile No. 82-42-472-7140

Authorized officer
LEE, Jong Kyung
Telephone No. 82-42-481-3360

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