Title: AUTOMATIC AND INTEGRATED CONTROL OF BOTTOM-HOLE PRESSURE

Abstract: A method for responding to an adverse fluid event such as a fluid gain or fluid loss event includes pumping a drilling fluid through a drilling system having a drill string and into a well bore. The drilling system also includes at least two pressure control components operatively coupled to the drill string. The bottom hole pressure of the well bore may be monitored. Once a fluid loss condition or a fluid gain condition is detected, a response for each of the at least two pressure control components to the fluid loss or fluid gain condition is determined. The responses for the at least two pressure control components are prioritized, and at least one of the pressure control components is adjusted to mitigate the adverse pressure condition.

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AUTOMATIC AND INTEGRATED CONTROL OF BOTTOM-HOLE PRESSURE

CROSS-REFERENCE TO RELATED APPLICATIONS

[001] This application claims priority to United States Non-Provisional Patent Application Serial No. 14/820319, which was filed on August 06, 2015, and is incorporated herein by reference.

BACKGROUND

[002] During drilling operations drilling fluid is pumped downhole to, among other things, provide hydrostatic pressure against the formation being drilled. The hydrostatic pressure provided by the drilling fluid in the annulus provides a static head which assists in maintaining the hydrostatic equilibrium in the well bore, thereby controlling formation fluid pressure to prevent a significant influx of fluid from the formation (i.e., a kick) and minimizing fluid loss into and stabilizing the formation through which the well is being drilled.

[003] There are two common types of pressure-controlled drilling: under balanced drilling and managed pressure drilling. In under balanced drilling, the down hole pressure is maintained below a formation pressure. During underbalanced drilling, fluid may be lost to the formation due to the pressure gradient between the formation and the well bore. While minimal losses to the formation are tenable, significant fluid loss to the formation may slow drilling operations as well as increase the cost of drilling the well. In managed pressure drilling, a series of chokes and a back pressure system control the downhole pressure in order to maintain a desired bottom hole pressure between a formation pressure and a fracture pressure. A concern with managed pressure drilling and underbalanced drilling is the potential for a large fluid influx from a high pressure pocket in the formation, otherwise known as a "kick." A kick is caused by the intrusion of salt water, formation fluids or gases into the drilling fluid which may lead to a blowout condition. Blowouts are hazardous, costly, and time consuming. A kick or blowout, if not mediated, may result in damage to drilling tools and systems and cause injury or death of workers.
The primary source of pressure and pressure control in the well bore is through the drilling fluid. The hydrostatic pressure caused by the weight of the drilling fluid is one of the variables used to control pressure while drilling. In addition to hydrostatic pressure, pump pressure, casing pressure, and the riser level can be affected to achieve a specific bottom-hole pressure. Different pressure conditions are desired under various drilling conditions, for example, in some drilling conditions constant casing pressure may be desired, while under other conditions, constant pump pressure and/or an adjustment to the riser level may be desired.

BRIEF DESCRIPTION OF DRAWINGS

Figure 1 shows a schematic diagram of a system for providing integrated control of bottom hole pressure in accordance with embodiments of the present disclosure.

Figure 2 shows a schematic diagram of a drilling system with respect to a programmable logic controller in accordance with embodiments of the present disclosure.

Figures 3 and 4 show a flow chart of a method in accordance with embodiments of the present disclosure.

Figures 5 and 6 show a flow chart of pressure control scenarios in accordance with embodiments of the present disclosure.

The figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of elements may not be shown in interest of clarity and conciseness.

DETAILED DESCRIPTION

Embodiments of the present disclosure are directed to a drilling system and methods for monitoring pressure conditions of drilling operations and responding to detection of an adverse fluid event. As used herein, the term "adverse fluid event" may refer collectively to either a fluid loss or fluid gain to the well bore. Specifically, embodiments of the present disclosure are directed to drilling systems and methods to improve efficiency and safety while drilling a
well bore by effectively mitigating adverse fluid events. Aspects of the present disclosure may also be used to provide an integrated approach to mitigating adverse fluid events.

[0011] Embodiments of the present disclosure include a drilling system for drilling a well bore having at least two pressure control variables and/or corresponding pressure control components. As used herein, the term "pressure control variables" or "pressure control components" may be used to refer to a variable and/or component that affects the hydrostatic pressure of fluid in the well bore. An example of a pressure control variable may include the flow rate of drilling fluid pumped into a drill string disposed in the well bore, pressure of a choke manifold, weight of mud being provided downhole, and level of fluid in the riser, while a corresponding pressure control component may be a rig pump pumping the drilling fluid into the drill string, the choke manifold, a tank mixing system, and riser pump. The pressure control components may be operatively connected to a programmable logic controller. The programmable logic controller may receive measurements from sensors located on and/or proximate the pressure control components, communicate the data from the sensors to a computer and/or processor, as well as send instructions to the pressure control components.

[0012] Operatively connecting the pressure control components to the programmable logic controller allows an integrated approach to monitoring and responding to pressure changes in the well bore. For example, when an adverse fluid event is detected in the well bore, the computer and/or a user may use the data aggregated from a plurality of sensors and each of the pressure control components to make an informed decision on how best to mitigate the adverse fluid event. According to some embodiments, the pressure control components and variables may be prioritized to indicate which pressure control component would be most effective in mitigating the adverse fluid event under current drilling conditions. The pressure control component determined to be most affected may be adjusted to mitigate the adverse fluid event.

[0013] Referring to Figure 1, a drilling system 100 in accordance with embodiments of the present disclosure is illustrated. The drilling system 100 is shown as an example of a system that may be used in accordance with the methods described herein and is not intended to limit the scope of the present disclosure. One skilled in the art will understand that a variety of drilling systems having various arrangements of components and equipment may be used in accordance with
embodiments of the present disclosure without departing from the scope of the present disclosure.

[0014] The drilling system 100 as illustrated includes at least a drilling riser 116, a blowout preventer (BOP) stack 114, and drill string 112. The drilling riser 116 may be a marine riser that extends from a drilling platform (not shown), to the BOP stack 114. The BOP stack is provided at the formation surface 106 (i.e., at or proximate the sea floor) of a well bore 104. The BOP stack 114 is provided, among other things, to regulate downhole pressure and seal the well bore 104 in the event of a blowout, i.e., large and destructive influx of fluid into a well bore.

[0015] The drill string 112 may extend through the drilling riser 116 such that an annular riser chamber 117 is formed between an outer diameter of the drill string 112 and an inner diameter of the drilling riser 116. A sensor 128, for example, a level sensor may be provided to the drilling riser 116 to monitor a level of fluid in the annular riser chamber 117. A bottom hole assembly 113 including a drill bit 115 may be disposed at a distal end of the drill string 112. In some embodiments, the bottom hole assembly 113 may include a measuring device 127. This measuring device 127 may be a monitoring-while-drilling (MWD), pressure-while-drilling (PWD), and/or logging-while-drilling tool (LWD). In other embodiments, the measuring device 127 may be positioned along the drill string 112, but may not be included in the bottom hole assembly 113. The measuring device 127 may collect data downhole during drilling operations. The data may be stored in the measuring device 127 and/or may be communicated to the surface using telemetry techniques, for example, mud telemetry.

[0016] The drilling system 100 may also include at least one rig pump 132 operatively coupled to the drill string 112 for providing fluid to the drill string 112 through in-flow line 101. As used herein, the term "operatively coupled" refers to two components being in direct or indirect fluid communication. As the volume of fluid pumped downhole affects the downhole pressure, the rig pump 132 may be a pressure control component. A sensor 122 may be connected to the rig pump 132 at or near the rig pump 132 to monitor the amount of fluid pumped to the drill string 112. The sensor 122 may, for example, measure a flow rate of fluid through in-flow line 101 and/or monitor the number of strokes of the pump 132. The drilling fluid
provided to the drill string 112 may exit the drill string 112 at the bottom of the well bore 104 proximate the drill bit 115. The drilling fluid may remove fresh cuttings from the cutting surfaces of the drill bit 115 and carry the cuttings up through a well bore annulus (i.e., the space between the drill string 112 and the walls of the well bore 104) toward the surface. This solids laden drilling fluid may be carried from the well bore 104 through return line 102 for processing. As used herein, the term "solids laden drilling fluid" or "solids laden fluid" may be used to refer to drilling fluid from the well bore 104 having cuttings solids therein.

[0017] Solids laden fluid exiting the well bore 104 through the return line 102 may be provided to a back pressure system 130. The back pressure system 130 is provided to stabilize the pressure of the well bore 104 by mediating the amount of solids-laden fluid drawn from the well bore 104. The back pressure system 130 may include at least a choke manifold 136 and a riser pump 138. In some embodiments, a pressure transducer 126 may be used to monitor the pressure of solids laden fluid delivered to the choke manifold 136. The choke manifold 136 is operatively coupled to the drill string 112 and provided to adjust the back pressure, which allows control of the pressure downhole. As the choke manifold 136 affects the downhole pressure, one skilled in the art may consider the choke manifold 136 to be a pressure control component as described herein. In some embodiments, the choke manifold 136 may include a plurality of chokes and or valves capable of handling and/or controlling a solids laden fluid.

[0018] The riser pump 138 is operatively coupled to the riser 116 and may be used to control the level of fluid in the annular riser chamber 117. As the level of fluid in the annular riser chamber 117 adds weight to the column of fluid in the annular riser chamber 117, thereby affecting the downhole pressure, one skilled in the art may consider the riser pump 138 to be a pressure control component as described herein. As illustrated in Figure 1, the fluid riser pump 138 is in fluid communication with the choke manifold 136. During operation, the fluid riser pump 138 may carry fluid, e.g., solids laden fluid, from the riser and pump the fluid through hose 137 to the choke manifold 136.

[0019] Solids laden fluid from the choke manifold 136 may be delivered to a series of separatory devices (not shown) for processing. For example, the fluid may be provided to a mud gas separator and/or a vibratory separator for removal of entrained gases and solids. The processed
fluid may be provided to a mud tank 135 for storage. One skilled in the art will understand
that although only a single tank is illustrated in Figure 1, a plurality of mud tanks may be
included in the drilling system 100 for storage. In some embodiments the mud tank 135 may
also be in fluid communication with rig pump 132. For example, the rig pump 132 may pump
processed fluid from the mud tank 135 into the drill string 112.

[0020] The flow rate of fluid delivered from the choke manifold 136 for processing in the return
line 102 may be measured by a flow meter 123. It will be appreciated that by monitoring
sensor 122 used to measure a flow rate of fluid through in-flow line 101 and flow meter 123,
it may be possible to determine an amount of fluid lost to the formation and/or an amount of
fluid entering the borehole 104 from the formation.

[0021] A mixing tank system 134 may be in fluid communication with mud tank 135. The mixing
tank system 134 may be operatively coupled to the drill string 112 and used to increase and/or
decrease the density of the processed mud stored in the mud tank 135 in order to affect the
bottom-hole pressure. As the weight of the drilling fluid delivered to the drill string 112 affects
the downhole pressure, one skilled in the art may consider the mixing tank system 134 to be a
pressure control component as described herein. In certain embodiments, a level sensor 124
may be provided to the mud tank 135 for monitoring a level of fluid within the mud tank.

[0022] As discussed above, drilling system 100 may include a plurality of sensors disposed about
the drilling system 100. Referring to Figure 2, examples of the plurality of sensors 120 may
include flow sensor 122 for monitoring an amount of fluid pumped into the drill string 112,
flow meter 123 for measuring the flow rate out from the well bore 104, level sensor 124 for
measuring a level of mud tank 135, pressure transducer 126 for measuring a pressure of fluid
exiting the marine riser 116, measuring device 127 for measuring a pressure downhole while
drilling, and level sensor 128 for measuring a height of fluid in the annular riser chamber
117. Said sensors 120 may be included in the drilling system 100 to monitor back pressure
conditions downhole and provide feedback to a pressure control system. One skilled in the art
will appreciate that embodiments of the present disclosure may include any number of the
sensors described above without departing from the scope of the present disclosure. For
example, in some embodiments one of these sensors may be included in the drilling system; in
other embodiments two, three, four, and/or all of the sensors may be included in the drilling system. One skilled in the art may also appreciate that the sensors described above are provided as examples and are not intended to limit the scope of the disclosure as other sensors for monitoring drilling conditions and back pressure in the well bore may be included without departing from embodiments of the present disclosure.

[0023] Referring to Figures 1 and 2, the drilling system 100 may also include a programmable logic controller (PLC) 152. The PLC 152 is provided to monitor data from the sensors 120 disposed about the drilling system 100. The PLC 152 may be operatively connected to each of the sensors 120. As used herein, the term "operatively connected" refers to a wired or wireless connection for the transfer of data. For example, according to some embodiments, the one or more sensors 120 may communicate wirelessly to the PLC 152.

[0024] The PLC 152 is also operatively connected to a processor 154. The processor 154 may receive the sensor 120 data from the PLC 152 to record, model, and analyze the data. For example, the processor 154 may include software to model the well bore 104 using the empirical data received by the PLC 152. The model may be used to monitor and/or analyze changes in the well bore 104 in or near real time. The modeling software may include details such as the well geometry, BHA assembly details, flow rate with frictional factors, directional profiles, temperature profiles, rheology information and many other variables. The model may be visually accessible to a user on a display operatively connected to the processor. Based on the model, a user may be able to predict and/or determine downhole conditions and if the well bore 104 is (or about to) experience an adverse fluid event. A memory drive of the processor 154 may save the raw data and/or model to use in future drilling applications.

[0025] The processor 154 may also include software to analyze an optimal response, e.g., an action taken to mitigate a pressure control variable, to an adverse fluid event. The analysis may consider the type of adverse fluid event (e.g., fluid loss or gain), speed of response (e.g., how long it will take for a response to affect bottom hole pressure, which could be performed by estimating a gas volume, as any change in gas volume affects the bulk modulus of the fluid thereby changing the speed of a pressure wave through the fluid), current drilling conditions (e.g., weight on bit, revolutions per minute, etc.), current drilling requirements (e.g., under-
balanced and/or managed pressure drilling), adverse effects of changing a fluid control parameter (e.g., effect on bottom hole cleaning and rate of penetration (ROP)). Based on the analysis, an optimal or prioritized response may be identified. The prioritized response may provide a recommendation of which pressure control variable and which corresponding pressure control component to adjust and, in some embodiments, by how much based on the factors noted above. In some embodiments, adjustments may be made until a desired bottom hole pressure is reached.

[0026] The PLC 152 may also be operatively connected to the pressure control components 131, e.g., rig pump 132, mixing tank system 134, control choke 136, and riser pump 138. One skilled in the art will appreciate that according to embodiments of the present disclosure at least two pressure control components may be operatively connected to the PLC 152. The PLC 152 may send instructions to the pressure control components 131 based on the analysis and prioritized response identified by the processor 154.

[0027] According to another aspect of this disclosure, there is provided a method of responding to an adverse fluid event. Referring to Figures 1 and 3, a method in accordance with embodiments disclosed herein may include pumping 301 a drilling fluid through a drill string 112 and into a well bore 104. The drilling fluid may be pumped from mud tank 135 using rig pump 132. The drill string 112 and/or well bore 104 may be operatively coupled to at least two pressure control components. The at least two pressure control components may be selected from a rig pump 132, a mixing tank system 134, a choke manifold 136, and/or a riser pump 138. One skilled in the art will appreciate that other pressure control components may be used without departing from the scope of the present disclosure.

[0028] The drilling fluid pumped downhole provides hydrostatic pressure to the well bore 104. Embodiments of the present disclosure include monitoring 302 a bottom hole pressure of the well bore 104. The bottom hole pressure may be monitored by measuring at least one of a mud tank 135 level, a flow rate of drilling fluid entering the drill string 112, a flow rate of solids laden drilling fluid exiting an annulus of the well bore 104, or a surface pressure of a drilling riser 116. The plurality of sensors (120 in Figure 2) disposed about the drilling system
100 may collect and communicate data on the measurements described above to the PLC 152. The data may be relayed to the PLC 152 in real-time.

[0029] Based on the measurements taken by the sensors disposed about the drilling system 100, embodiments of the present disclosure may detect 303 a fluid loss condition or a fluid gain condition. According to some embodiments, a model of the drilling operations may be rendered in order to detect the fluid loss condition or the fluid gain condition. Once a fluid loss or fluid gain condition has been detected an appropriate response for each of the at least two pressure control components to the fluid loss or fluid gain condition may be determined 304. In some embodiments, this determination may be performed by the model and/or processor 154. In some embodiments, a user may survey the model and make a determination to modify the recommendation of the model. For example, in the event of a fluid gain condition, an appropriate response for the rig pump 132 may be to increase a pump rate of fluid to the formation 105, increasing a choke pressure, increasing a level of fluid in the riser, and/or increasing a weight of the drilling fluid pumped down hole 104.

[0030] Embodiments of the present disclosure also include prioritizing 305 the responses for the at least two pressure control components. The prioritizing of each of the responses of two or more pressure control components may be based on various operating variables including, for example, downhole drilling requirements, impact on rate of penetration, impact on bottom hole cleaning, and speed of response, i.e., length of time response takes to implement and length of time for response to affect bottom hole pressure, downhole drilling requirements, and magnitude of desired change in pressure. In some embodiments, the prioritization may be performed by the model and/or processor 154. In some other embodiments, a user may survey the model and prioritize the responses. A detailed discussion of how the prioritization may be implemented is provided below with reference to Figures 5 and 6.

[0031] Based on the prioritization of the responses, at least one of the pressure control components may be adjusted 306 to mitigate the adverse fluid event. According to some embodiments, the adjustment may be performed automatically using the PLC 152. The processor 154 may be configured to prioritize the responses, i.e., rank the responses based on one or more operating variables, as described above, so that an optimal response for a given operating variable or set
of operating variables may be selected. The pressure control component determined to most effectively mitigate the adverse fluid event under the present drilling conditions may be identified. The PLC 152 may send instructions to adjust said pressure control component.

[0032] For example, for a fluid gain event where a swift response to the fluid gain event is desired, a decision between increasing the amount of fluid pumped from rig pump 132 to the drill string 112 and increasing a weight of drilling fluid pumped downhole with the tank mixing system 134 may be made. The PLC prioritizes the at least two responses based on the analysis and determination that rig pump 132 may provide faster correction to safe drilling pressure conditions. As such, the PLC may prioritize increasing the amount of fluid pumped to the drill string 112 with rig pump 132 over increasing a weight of the drilling fluid with the mixing tank system 134. The processor 154 may send instructions to the PLC 152 to communicate said instructions to the pressure control component, e.g., rig pump 132, to implement the response, for example, adjusting, e.g., increase, a pump rate. Thus, this system provides a series of decision either successive or parallel to control pressure within all boundaries of the well instead of at a single location.

[0033] In some situations, adjusting a single pressure control component may not be sufficient to mitigate the adverse fluid event. In such situations, a second pressure control component may be adjusted thereby adjusting the corresponding pressure control variable. Continuing the example discussed above, if fluid continues to enter the well bore 104 from the formation 105 after the pump rate of the rig pump 132 is increased, a second pressure control component may be adjusted based on the continuous monitoring of sensors. For example, a choke located in the choke manifold 136 may be closed in order to increase the bottom hole pressure to prevent further fluid influx from the formation 105 and/or increase bottom hole pressure.

[0034] For scenarios where a fluid loss condition is detected, the response by the PLC 152 may include adjusting, e.g., decreasing, a pump rate of a rig pump 132, increasing a pump rate of the riser pump 138, opening a choke disposed in the choke manifold 136, and/or decreasing a weight of the drilling fluid pumped down hole 104 with the mixing tank system 134. For scenarios where a fluid gain condition is detected, the response by the PLC 152 may include adjusting, e.g., increasing, a pump rate of a rig pump 132, decreasing a pump rate of the riser
pump 138, closing a choke disposed in the choke manifold 136, and increasing a weight of the drilling fluid pumped down hole 104 with the mixing tank system 134.

[0035] According to another aspect of this disclosure, there is provided a method of maintaining a constant casing pressure, constant pump pressure, and/or riser level. Referring to Figures 1, 2, and 4, a method in accordance with embodiments disclosed herein may include pumping 401 a drilling fluid at an initial pump rate through a drill string 112, while maintaining a first casing pressure and a first riser level. The hydrostatic pressure may be created by pumping fluid through in-flow line 101 and through the drill string 112. In some embodiments, an adverse fluid condition may be detected. The adverse fluid condition may be one selected from a fluid loss condition or a fluid gain condition. The detecting may include sending a signal from a sensor 120 measuring at least one selected from a mud tank 135 level, a flow rate of drilling fluid entering the drill string 112, a flow rate of solids laden drilling fluid exiting an annulus of the well bore 104, and/or a surface pressure of a drilling riser 116. The sensor 120 may be operatively connected to a PLC 52 such that the sensor transmits the measurements to the PLC 52 for further analysis.

[0036] In some embodiments, the measurements may be input into a model of the well bore and drilling system 100. Based on the measurements, a potential response of at least two pressure control components to the adverse pressure condition may be identified 402 in order to maintain at least one of a constant casing pressure, constant pump pressure, or riser level. For example, if a casing pressure is below a desired level, the pump rate of a riser pump 138 may be decreased in order to increase the well bore 104 pressure.

[0037] Once the potential responses of the pressure control components 131 have been identified, said responses may be prioritized 403 based on at least one selected from a length of time to implement a response, a length of time for the response to take effect, magnitude of desired change in pressure, and drilling requirements such as rate of penetration and impact on bottom hole cleaning. A detailed discussion of how the prioritization may be implemented is provided below with reference to Figures 5 and 6.

[0038] In order to maintain a constant casing pressure, constant pump pressure, and/or riser level, one of the at least two pressure control components may be adjusted 404. In some
embodiments, the analysis may recommend that at least two pressure control variables and hence at least two pressure control components may be adjusted simultaneously. The adjusting may include sending instructions from a PLC 152 to one of the at least two pressure control components based on the analysis of the response. For example, the PLC 152 may instruct a choke disposed in the choke manifold 136 to fully open in order to reduce pressure in the well bore 104 to mitigate a fluid gain condition.

[0039] Embodiments of the present disclosure may further include monitoring a bottom hole pressure after adjusting one of the at least two pressure control components. Monitoring after adjusting one of the at least two pressure control components allows a user to determine if the adjustment was effective in maintaining at least one of a constant casing pressure, constant pump pressure, and/or riser level. The settings of the pressure control components may be maintained until another adverse fluid event or a corresponding pressure control variable is not at a desired value. In the event that at least one of a constant casing pressure, constant pump pressure, and/or riser level is not at the desired value, a second of the at least two pressure control components may be adjusted.

Pressure Control Scenarios

[0040] Pressure control scenarios are provided herein as examples of potential issues that may arise during drilling operations and how a user may mitigate those issues according to embodiments of the present disclosure. One skilled in the art will appreciate that numerous scenarios may arise during drilling and that numerous responses may be implemented depending on a variety of operating variables including, for example, a length of time to implement a response, a length of time for the response to take effect, magnitude of desired change in pressure, and drilling requirements such as rate of penetration and impact on bottom hole cleaning.

[0041] Referring to Figures 1 and 5, in a first pressure control scenario, a drill string 112 is drilling formation 105 with slightly underbalanced pressure 501. For example, the equivalent circulating density (ECD) may be 13 ppg. In the present scenario, the choke manifold 136 is used to generate back pressure 503 to maintain a balance between the well bore fluids and the fluid in the formation 105. For example, in a well where a surface pressure of 100 psi gives a
13.1 ppg circulating density and a particular well depth, the choke manifold 136 may be used to create 100 psi of back pressure, which may give the ECD a set point of 13.1 ppg. Although, the choke manifold 136 provides back pressure, fluid gain 505 into the well bore 104 from the formation 105 is detected by sensors disposed in the drilling system 100 operatively connected to PLC 152. One skilled in the art will understand that the pressure values provided are merely exemplary and not intended to limit the scope of the present disclosure.

[0042] Once the adverse fluid event, in this case, fluid gains condition has been detected by the drilling system 100, the processor 154 may conduct an analysis to determine which pressure control component to adjust 510, e.g., whether to increase choke pressure, increase a riser fluid level, increase a pump speed, and/or increase a mud weight. By increasing a pump speed of the rig pump 132, the circulating pressure of fluid in the well bore 104 may be increased 512, thereby increasing a bottom-hole pressure. Increasing pump rate is not selected 522, because the current pump speed corresponds to optimal bottom hole cleaning and rate of penetration conditions. By increasing the mud weight the hydrostatic pressure in the well bore 104 may also increase 514, thereby increasing bottom-hole pressure. Increasing the mud weight is not selected 524, because to do so would be too time consuming as the existing mud would have to be mixed with tank mixing system 134 and the size of the gas pocket causing the fluid gain is unclear. By increasing the choke pressure an increase in the annular riser chamber 117 may also increase 516, thereby increasing bottom-hole pressure. Decreasing the pump rate and/or turning off the riser pump 138 is selected because doing so reduces damage to the riser pump 138 and creates failure tolerant conditions in response to the adverse fluid event.

[0043] Ultimately, the drilling system 100 elects to increase the fluid level 518 in the annular riser chamber 117 based on the prioritizing of the response based on the indicated operating variables. For example, the pump rate of the riser pump 138 may be decreased in order to increase the fluid level in the annular riser chamber 117. The pump rate of riser pump 138 is maintained and/or further decreased until the riser is full. The measurements for the sensors are still indicating that fluid is entering the well bore 104 from the formation.

[0044] In response, the processor 154 may conduct another analysis to determine which pressure control component to adjust 510, e.g., whether to increase choke pressure, increase a pump
speed, and/or increase a mud weight. By increasing a pump speed of the rig pump 132, the circulating pressure of fluid in the well bore 104 may increase 532, thereby increasing a bottom-hole pressure. Increasing pump rate is not selected 542, because the current pump speed still corresponds to optimal bottom hole cleaning and rate of penetration conditions. By increasing the mud weight the hydrostatic pressure in the well bore 104 may also increase 536, thereby increasing bottom-hole pressure. Increasing the mud weight is not selected 544, because, again, to do so would be too time consuming and the size of the gas pocket causing the fluid gain is unclear. Increasing the choke pressure is selected 546, as the most efficient response to mitigate the fluid gain based on the prioritized operating variables, namely, quickly responding to the adverse fluid event without compromising bottom hole cleaning and rate of penetration by the PLC 152. Increasing the choke pressure may also give the user and/or operator time to assess the drilling situation while the drilling system is being stabilized toward a safer steady state.

[0045] Referring to Figures 1 and 6, in a first pressure control scenario, a drill string 112 is drilling formation 105 with slightly underbalanced pressure 601. For example, the equivalent circulating density (ECD) may be 13 ppg. In the present scenario, the choke manifold 136 is being used to generate back pressure 603 to maintain a balance between the well bore fluids and the fluid in the formation 105. Particularly, in this scenario, maintaining a casing pressure is desired. For example, the choke manifold 136 may be used to create 100 psi of back pressure, which may give the ECD a set point of 13.1 ppg. Although, the choke manifold 136 provides back pressure, losses are detected 605 by sensors disposed in the drilling system 100 operatively connected to PLC 152.

[0046] Once the adverse fluid event, in this case, fluid loss condition has been detected by the drilling system 100, the processor 154 may conduct an analysis to determine which pressure control component to adjust 610, e.g., whether to decrease choke pressure, decrease a riser fluid level, decrease a pump speed, and/or decrease a mud weight. By decreasing a pump speed of the rig pump 132, the circulating pressure of fluid in the well bore 104 may decrease 612, thereby decreasing a bottom-hole pressure. Lowering the pump rate is not selected 622, because doing so would reduce the efficiency of the bottom hole cleaning and impact the ROP. By decreasing the mud weight, the hydrostatic pressure in the well bore 104 may also
decrease 614, thereby decreasing bottom-hole pressure. Decreasing the mud weight is not selected 624, because, to do so would be too time consuming and may compromise the integrity of the well. Decreasing the riser level 616, thereby reducing the weight of fluid in the annular riser chamber 117, is not selected 626 as doing so reduces damage to the riser pump 138.

[0047] The system selects removing choke pressure 618 in a controlled rate to decrease the bottom hole pressure in order to mitigate the fluid loss to the formation due to the relatively rapid downhole response. Despite the adjustment made to the choke manifold 136, fluid loss to the formation 105 continues 629.

[0048] In response, the processor 154 may conduct another analysis to determine which pressure control component and corresponding pressure control variable to adjust 630, e.g., whether to lower a level of fluid in the annular riser chamber 117, decrease a pump speed, and/or decrease a mud weight. By decreasing a pump speed of the rig pump 132, the circulating pressure of fluid in the well bore 104 may decrease 632, thereby decreasing a bottom-hole pressure. Lowering the pump rate is not selected 642, because doing so would reduce the efficiency of the bottom hole cleaning and impact the ROP. By decreasing the mud weight, the hydrostatic pressure in the well bore 104 may also decrease 634, thereby decreasing bottom-hole pressure. Decreasing the mud weight is not selected 644, because, to do so would be too time consuming and may compromise the integrity of the well. Decreasing the riser level 636, thereby reducing the weight of fluid in the annular riser chamber 117, is selected 646 as the most efficient response to mitigate the fluid gain in a timely manner without compromising bottom hole cleaning, well bore integrity, and rate of penetration.

[0049] According to other pressure control scenarios it may be desirable to maintain a constant casing pressure, constant pump pressure, and/or riser level. In pressure control scenarios where it is desirable a constant casing pressure is maintained, for example, when attempting to kill a well, the casing pressure may be held constant while bringing the rig pump(s) 132 up to the kill rate. For example, the pressure control choke 136 may be adjusted to accommodate any fluctuations in back pressure caused by changing the pump rate of the pumps. After reaching the kill rate, the pump pressure may be controlled by, for example, the PLC, as the influx is circulated out. The casing pressure may be monitored by measuring device 127 and adjusted.
accordingly. For example, a drilling fluid with added weight mixed in mixing tanks 134 may be pumped in while keeping casing pressure constant. The processor 154 may determine an optimal weight based on previous flow information, for example, the system may check for previous potential gains in flow out to determine probable fluid influx events which could indicate at what pressure said influxes occurred. The weighted fluid may be pumped by rig pumps 132 into the drill string 112 and exit the drill bit 115. The PLC 152 and processor 154 may control the pump pressure and monitor the casing pressure to ensure the casing pressure is kept constant. Once the weighted fluid has been circulated downhole, the PLC 152 may instruct the rig pumps 132 to shut down while holding casing pressure constant. In this scenario both the rig pump and choke manifold may work together symbiotically in order to achieve the optimal results.

[0050] In another pressure control scenario it may be desirable to reduce the weight of the drilling fluid in order to stay within a fracture gradient through a narrow zone. In this scenario effective hole cleaning may become an issue, as such the pump rate may be held constant. According to the present scenario, the choke manifold may be fully open, i.e., the choke manifold 136 may not be adjusted to affect the ECD further. Depending on the length of the zone and other factors, a model of the drilling operations may provide an analysis to determine an optimal response to the pressure control scenario. For example, the model may determine that the mud weight should be reduced and/or a pump rate of the riser pump 138 should be increased to pump fluid out of the riser 116 in order to reduce bottom-hole pressure if a rapid response is desired.

[0051] Accordingly, embodiments of the present disclosure provide a system and methods for efficiently and effectively mitigating potential fluid loss and fluid gain events during drilling operations by taking an integrated approach to managing downhole pressure. By evaluating the potential response and subsequent effect on drilling operations of each pressure control component, an efficient and timely response to an adverse fluid event may be carried out. This process allows immense flexibility while drilling a well and may facilitate an efficient, versatile and safe approach to drilling. Furthermore, by using sophisticated well modeling software, embodiments of the present disclosure provide the ability to employ the optimal method of control given the current conditions.
[0052] Although the preceding description has been described herein with reference to particular means, materials and embodiments, it is not intended to be limited to the particulars disclosed herein. Rather, it extends to all functionally equivalent structures, methods and uses, such as are within the scope of the appended claims.
What is claimed is:

1. A method comprising:
   pumping a drilling fluid through a drill string and into a well bore, wherein at least two pressure control components are operatively coupled to the drill string;
   monitoring a bottom hole pressure of the well bore;
   detecting a fluid loss condition or a fluid gain condition;
   determining a response for each of the at least two pressure control components to the fluid loss or fluid gain condition;
   prioritizing the responses for the at least two pressure control components; and
   adjusting one of the pressure control components to mitigate the adverse pressure condition.

2. The method of claim 1, further comprising adjusting a second of the at least two pressure control components to mitigate the adverse pressure condition.

3. The method of claim 1, wherein the prioritizing is based on at least one of downhole drilling requirements, impact on rate of penetration, impact on bottom hole cleaning, speed of response, downhole drilling requirements, or magnitude of desired change in pressure.

4. The method of claim 1, wherein the monitoring the bottom hole pressure further comprises at least one of measuring at least one selected from a mud tank level, a flow rate of drilling fluid entering the drillstring, a flow rate of solids laden drilling fluid exiting an annulus of the well bore, or a surface pressure of a drilling riser.

5. The method of claim 1, wherein a fluid loss condition is detected and the adjusting comprises at least one selected from the group consisting of decreasing a pump rate of a rig pump, increasing a pump rate of the riser pump, opening a control choke, and decreasing a weight of the drilling fluid pumped downhole.
6. The method of claim 1, wherein a fluid gain condition is detected and the adjusting comprises at least one selected from the group consisting of increasing a pump rate of a rig pump, decreasing a pump rate of the riser pump, closing a control choke, and increasing a weight of the drilling fluid pumped downhole.

7. The method of claim 1, wherein the monitoring further comprises relaying measurements from a plurality of sensors disposed about a drilling system, including the drill string and pressure control components, to a programmable logic controller.

8. The method of claim 1, wherein the adjusting includes automatically adjusting the at least one of the pressure control components based on the prioritized response.

9. A method comprising:
pumping a drilling fluid down a drill string at a first pump pressure, while maintaining a first casing pressure, and first riser level;
identifying at least two pressure control components to maintain at least one of a casing pressure, pump pressure, and/or riser level;
prioritizing at least one of the pressure control components based on at least one of a length of time to implement the response, a length of time for the response to take effect, magnitude of desired change in pressure, or drilling requirements; and adjusting one of the at least two pressure control components to maintain at least one of the casing pressure, pump pressure, or riser level.

10. The method of claim 9, further comprising detecting an adverse fluid condition, wherein the adverse fluid condition is one selected from a fluid loss condition or the fluid gain condition.

11. The method of claim 9, further comprising operatively connecting the at least two pressure control components to a programmable logic controller.

12. The method of claim 11, wherein the adjusting further comprises sending instructions from the programmable logic controller to the at least one of the pressure control components based on the analysis of the response.
13. The method of 9, further comprising monitoring a bottom hole pressure after adjusting one of the at least two pressure control components.

14. The method of claim 13, further comprising determining the adverse pressure condition persists and adjusting a second of the at least two pressure control components.

15. The method of claim 9, wherein the detecting further comprises transmitting a signal from a sensor to a programmable logic controller measuring at least one selected from the group consisting of a mud tank level, a flow rate of drilling fluid entering the drillstring, a flow rate of solids laden drilling fluid exiting an annulus of the well bore, and a surface pressure of a drilling riser.

16. The method of claim 9, further comprising inputting the measurements into a model of the well bore to determine a presence of the adverse pressure condition.

17. The method of claim 9, wherein the adjusting further comprises adjusting the at least two pressure control components simultaneously.

18. A system comprising:
   a drill string;
   at least two bottom hole pressure control components operatively coupled to the drill string;
   a programmable logic controller operatively connected to the at least two bottom hole pressure control components; and
   a processor operatively connected to the programmable logic controller and configured to prioritize one of the at least two bottom hole pressure control components during a detected change in pressure.

19. The system of claim 18, wherein the at least two bottom hole pressure control components are selected from the group consisting of a rig pump, a riser pump, a control choke, and a mud tank.

20. The system of claim 18, further comprising a plurality of sensors operatively connected to the drill string and the at least two bottom hole pressure control components.
Pumping drilling fluid through a drillstring to a wellbore

Monitoring a bottom hole pressure of the wellbore

Detecting a fluid loss or a fluid gain condition

Determining a response for at least two pressure control components

Prioritizing the responses

Adjusting at least one of the pressure control components

FIG. 3

Pumping a drilling fluid down a drill string

Identifying a response of at least two pressure control components

Prioritizing the responses of the at least two pressure control components

Adjusting one of the at least two pressure control components

FIG. 4
Drilling slightly underbalanced with an ECD of 13.0ppg

The choke is being used to create 100psi backpressure to maintain balance. This gives an ECD setpoint of 13.1ppg.

Gains are detected by the system and are becoming an concern.

Raising the pump speed increases the circulating pressure thereby increasing BHP.

Raising the choke pressure increases the annulus pressure which increases BHP.

Increasing choke pressure increase riser fluid, increase pump speed or raise mudweight?

Raising the mudweight increases the hydrostatic pressure and results in a higher BHP.

Lowering the pumps is not picked because hole cleaning and ROP are at optimal conditions.

Turning off the return pump for the riser determined to be more efficient.

The system has elected to increase the fluid column in the riser. the riser is now 100% full but the active tank system is still showing gains.

Increasing the mudweight is too time consuming and this may only be a small pocket of gas.
Lowering the pumps is not picked because hole cleaning and ROP are at optimal conditions.

Raising the pump speed increases the circulating pressure thereby increasing BHP.

Increase choke pressure, increase pump speed or increase mudweight?

Raising the mudweight increases the hydrostatic pressure and results in a higher BHP.

Increasing the mudweight is too time consuming and this may only be a small pocket of gas.

The system has elected to increase the choke pressure to control gains.

Raising the choke pressure increases the annulus pressure which increases BHP.

FIG. 5B
Pressure Control Scenario

Drilling slightly underbalanced with an ECD of 13.0 ppg

The choke is being used to create 100 psi backpressure to maintain balance. This gives an ECD setpoint of 13.1 ppg.

Losses are detected by the system and are becoming an issue.

Pressure Control Decision Tree

Decreasing the pump speed reduces the circulating pressure thereby reducing BHP.

Decreasing the riser level reduces the column weight in the riser thereby reducing BHP.

Open choke decrease riser fluid, reduce pump speed or reduce mudweight?

Decreasing the mudweight reduces the hydrostatic pressure and results in a lower BHP.

Lowering the mudweight is too time consuming and could compromise well integrity at the shoe.

Lowering the pumps is not picked because hole cleaning and ROP could be degraded.

Decreasing the riser level is not picked because opening the choke would provide the fastest response.

The system responds by removing choke pressure slowly until the losses subside.

FIG. 6A
Lowering the pumps is not picked because hole cleaning and ROP could be degraded.

Decreasing the pump speed reduces the circulating pressure thereby reducing BHP.

Decrease riser fluid, reduce pump speed or reduce mudweight?

Choke is open 100% but the losses are persisting.

Decreasing the mudweight reduces the hydrostatic pressure and results in a lower BHP.

Decreasing the riser level reduces the column weight in the riser thereby reducing BHP.

Lowering the mudweight is too time consuming and could compromise well integrity at the shoe.

The system has elected to decrease the riser level in order to eliminate losses.

FIG. 6B
A. CLASSIFICATION OF SUBJECT MATTER

E21B 21/08(2006.01)i, E21B 47/06(2006.01)i, E21B 44/00(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 21/08; E21B 7/00; E21B 34/04; E21B 7/12; E21B 44/00; E21B 47/06

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 database consulted during the international search (name of database and, where practicable, search terms used)
eKOMPASS/KIPO internal & Keywords: drilling fluid, pressure, well bore, pressure control component, fluid loss, fluid gain, response, prioritizing

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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

Date of the actual completion of the international search: 10 November 2016 (10.11.2016)

Date of mailing of the international search report: 10 November 2016 (10.11.2016)

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