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(54) Title: CLOSED LOOP DRILLING FLUIDS CIRCULATION AND MANAGEMENT SYSTEM

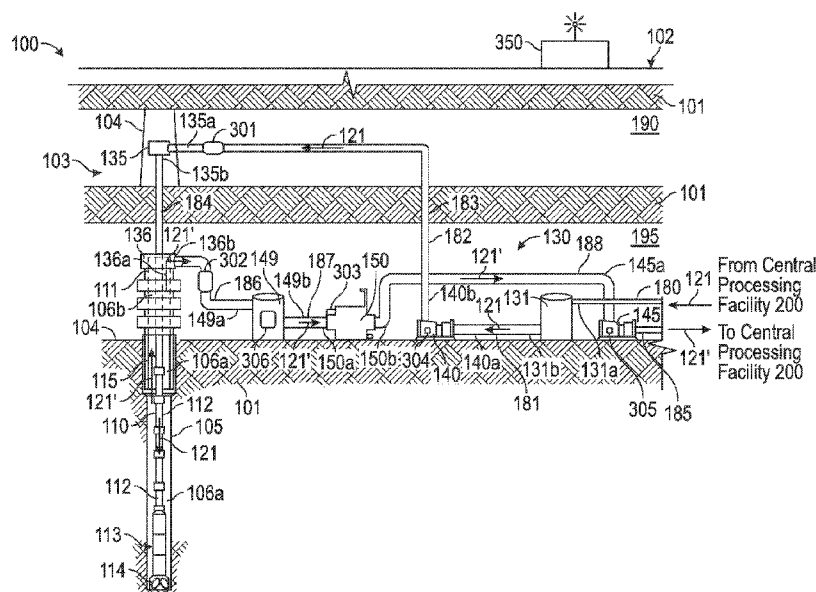


FIG. 2

(57) Abstract: A closed loop drilling fluids circulation system includes a first drilling fluid circulation system disposed at a first subterranean drill site. The first drilling fluid circulation system includes a supply tank for holding clean drilling fluid and a solids control device configured to separate solids from used drilling fluid. In addition, the system includes a central processing facility disposed at a location remote from the first drill site and configured to receive used drilling fluid from the solids control device and supply clean drilling fluid to the supply tank.



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CLOSED LOOP DRILLING FLUIDS CIRCULATION AND MANAGEMENT SYSTEM**CROSS-REFERENCE TO RELATED APPLICATIONS**

[0001] This application claims benefit of U.S. provisional patent application Serial No. 61/783,979, filed March 14, 2013, and entitled “Closed Loop Drilling Fluids Circulation and Management System,” which is hereby incorporated by reference in its entirety.

**STATEMENT REGARDING FEDERALLY SPONSORED
RESEARCH OR DEVELOPMENT**

[0002] Not applicable.

BACKGROUND

[0003] Embodiments described herein relate generally to systems and methods for processing drilling mud or fluid. More particularly, embodiments described herein relate to a sealed, gas-tight closed loop systems and methods for managing and controlling the processing of drilling fluid used in subterranean drilling operations.

[0004] In drilling a borehole (or wellbore) into the earth for the recovery of hydrocarbons from a subsurface formation, it is conventional practice to connect a drill bit to the lower end of a drill string, then rotate the drill bit with weight-on-bit (WOB) applied to enable the bit to progress downward into the earth to create the desired borehole. A typical drillstring usually includes drill pipe sections connected end-to-end and a bottom hole assembly (BHA) between the drill bit and the lower end of the drill string. The BHA is typically suited to the requirements of the well being drilled and may include subcomponents such as drill collars, reamers, stabilizers, mud motor, or other drilling tools and accessories. In general, the drill bit can be rotated from the surface with a top drive or rotary table and/or rotated with a mud motor disposed in the drillstring. During drilling operations, drilling fluid or mud is pumped from the surface down the drillstring and out nozzles in the face of the drill bit. The drilling fluid returns to the surface via the annulus disposed between the drill string and the sidewall of the borehole. During drilling operations, the well is hydrostatically controlled with an atmospheric solids separation system, which requires a high level of manual intervention.

[0005] Drilling fluid is typically made of a finely ground clay base material to which water, oil, or both are added along with select chemicals to form a viscous fluid designed to meet specific physical properties appropriate for the anticipated borehole conditions. The drilling fluid serves four main purposes—aids in cooling the drill bit, which increases its useful life; flushes the cuttings or “solids” from the wellbore and returns them to the surface for processing by a solid control system; controls pressures in the well to prevent blowouts; and leaves a thin layer of the finely ground clay base material along the well bore walls, which helps prevent caving in of the wellbore wall. Drilling fluid is a complex composition carefully engineered and tailored to each individual well and drilling operation. Drilling fluid is relatively expensive, and thus, is typically cleaned and recirculated through the drilling system. In particular, when drilling fluid returns to the surface via the annulus, the drilling fluid is processed to remove borehole cuttings and undesirable gases, treated to adjust its chemical composition, and then recirculated back into the borehole through the drillstring.

[0006] The solid control system typically includes mechanical solids removal equipment such as a shale shaker to remove larger cuttings, and a desander, desilter, mud cleaner, and/or centrifuge to remove smaller solids particles. The formation may contain hazardous gas such as hydrogen sulfide (H_2S), which becomes entrained in the drilling fluid. Gases entrained in the returned drilling fluids may dissociate from the drilling fluid and be vented at the drill site, or intentionally removed with a degasser. In either case, gases exiting the drilling fluid are typically vented or flared at the drill site, and thus, can pose process challenges and contribute to greenhouse gas emissions. Gases vented from drilling fluid can be particularly problematic when drilling in a closed and confined environment such as in a subterranean tunnel. In addition, in environmentally sensitive areas, there may be severe restrictions on the venting and/or flaring of released gases, as well as the footprint available for drilling operations and related drilling mud circulation equipment.

BRIEF SUMMARY OF THE DISCLOSURE

[0007] These and other needs in the art are addressed in one embodiment by a closed loop drilling fluids circulation system. In an embodiment, the system comprises a first drilling fluid circulation system disposed at a first subterranean drill site. The first drilling fluid circulation system includes a supply tank for holding clean drilling fluid and a solids control device

configured to separate solids from used drilling fluid. In addition, the system comprises a central processing facility disposed at a location remote from the first drill site and configured to receive used drilling fluid from the solids control device and supply clean drilling fluid to the supply tank.

[0008] These and other needs in the art are addressed in another embodiment by a drilling fluids circulation system disposed at a drill site. In an embodiment, the system comprises a pressurized storage vessel for holding clean drilling fluid at the drill site. In addition, the system comprises a supply pump configured to pump clean drilling fluid from the pressurized storage vessel down a drill string. Further, the system comprises a pressurized surge vessel configured to receive and hold used drilling fluid from an annulus disposed about the drill string. Still further, the system comprises a sealed and pressurized solids control device configured to receive used drilling fluid from the surge vessel and separate solids from used drilling fluid. Moreover, the system comprises a return pump configured to pump used drilling fluid from the solids control device.

[0009] These and other needs in the art are addressed in another embodiment by a method for circulating and processing drilling fluid. In an embodiment, the method comprises (a) receiving used drilling fluid from a borehole at a first subterranean drill site. In addition, the method comprises (b) preventing the escape of gases from the used drilling fluid at the first subterranean drill site. Further, the method comprises (c) pumping the used drilling fluid from the first subterranean drill site to a central processing facility disposed at the surface after (b). Still further, the method comprises (d) processing the used drilling fluid to form clean drilling fluid at the central processing facility. Moreover, the method comprises (e) pumping the clean drilling fluid from the central processing facility to the first subterranean drill site after (d).

[0010] Embodiments described herein comprise a combination of features and advantages intended to address various shortcomings associated with certain prior devices, systems, and methods. The foregoing has outlined rather broadly the features and technical advantages of the invention in order that the detailed description of the invention that follows may be better understood. The various characteristics described above, as well as other features, will be readily apparent to those skilled in the art upon reading the following detailed description, and by referring to the accompanying drawings. It should be appreciated by those skilled in the art that the conception and the specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the invention. It

should also be realized by those skilled in the art that such equivalent constructions do not depart from the spirit and scope of the invention as set forth in the appended claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0011] For a detailed description of the preferred embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0012] Figure 1 is a schematic view of an embodiment of a closed loop drilling fluids circulation system in accordance with the principles disclosed herein;

[0013] Figure 2 is a schematic, partial cross-sectional view of one subterranean drilling site of Figure 1 including a drilling system and a local drilling fluids circulation system;

[0014] Figure 3 is a schematic, partial cross-sectional view of the solids control device of Figure 3;

[0015] Figure 4 is a schematic view of a control system for automating, controlling, and operating the local drilling fluids circulation system of Figure 2;

[0016] Figure 5 is a graphical illustration of a method for automating, controlling, and operating the local drilling fluids circulation system of Figure 2 with the control system of Figure 4; and

[0017] Figure 6 is a schematic view of the central processing facility of Figure 1.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0018] The following description is exemplary of embodiments of the disclosure. These embodiments are not to be interpreted or otherwise used as limiting the scope of the disclosure, including the claims. One skilled in the art will understand that the following description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and is not intended to suggest in any way that the scope of the disclosure, including the claims, is limited to that embodiment.

[0019] The drawing figures are not necessarily to scale. Certain features and components disclosed herein may be shown exaggerated in scale or in somewhat schematic form, and some details of conventional elements may not be shown in the interest of clarity and conciseness. In some of the figures, one or more components or aspects of a component may be not displayed or may not have reference numerals identifying the features or components that are identified elsewhere in order to improve clarity and conciseness of the figure.

[0020] The terms “including” and “comprising” are used herein, including in the claims, in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to” Also, the term “couple” or “couples” is intended to mean either an indirect or direct connection. Thus, if a first component couples or is coupled to a second component, the connection between the components may be through a direct engagement of the two components, or through an indirect connection that is accomplished via other intermediate components, devices and/or connections. In addition, if the connection transfers electrical power or signals, whether analog or digital, the coupling may comprise wires or a mode of wireless electromagnetic transmission, for example, radio frequency, microwave, optical, or another mode. So too, the coupling may comprise a magnetic coupling or any other mode of transfer known in the art, or the coupling may comprise a combination of any of these modes. In addition, as used herein, the terms “axial” and “axially” generally mean along or parallel to a given axis (e.g., central axis of a body or a port), while the terms “radial” and “radially” generally mean perpendicular to the axis. For instance, an axial distance refers to a distance measured along or parallel to the axis, and a radial distance means a distance measured perpendicular to the axis. Any reference to up or down in the description and the claims will be made for purpose of clarification, with “up,” “upper,” “upwardly,” or “upstream” meaning toward the surface of the well and with “down,” “lower,” “downwardly,” or “downstream” meaning toward the terminal end of the well, regardless of the well bore orientation. In some applications of the technology, the orientations of the components with respect to the surroundings may be different. For example, components described as facing “up,” in another application, may face to the left, may face down, or may face in another direction. Still further, as used herein the terms “sealed” and “gas-tight” may be used to describe components, devices, and equipment that allow fluids to flow therethrough but prevent gases from escaping into the surrounding environment during normal operating conditions.

[0021] Referring now to Figure 1, a closed loop drilling fluids circulation and management system 10 is shown. In this embodiment, system 10 includes a plurality of drilling fluid circulation systems 130 and a central drilling fluid processing facility 200. Each system 130 is disposed at a subterranean drill site 100 and central processing facility 200 is disposed at the surface 102. Subterranean drilling sites 100 are geographically located at different locations relative to each other and relative to central processing facility 200. For example, sites 100 and central processing facility 200 may be located a mile or more apart from each other. Thus, sites

100 may be described as being “remote” relative to each other, and central processing facility 200 may be described as being “remote” relative to each drilling site 100. Although two remote drilling sites 100 are shown in Figure 1, embodiments of closed loop drilling fluids circulation systems disclosed herein (e.g., system 10) can include fewer or more drilling sites (e.g., a single site or more than two drilling sites). Further, although drilling sites 100 are both located remote from the central processing facility 200 in this embodiment, it should be appreciated that the central processing facility (e.g., central processing facility 200) could be located at one of the drill sites (e.g., drill site 100).

[0022] Referring now to Figure 2, one subterranean drilling site 100 is shown, it being understood that each drill site 100 is the same. Drilling site 100 is disposed in formation 101 below the surface 102. In particular, drilling site 100 includes an upper operating tunnel 190 extending horizontally through formation 101, a lower operating tunnel 195 extending through formation 101, and a plurality of bores or conduits 183, 184 extending vertically between tunnels 190, 195 in formation 101. Operating tunnels 190, 195 are oriented parallel to each other and with upper tunnel 190 positioned above lower tunnel 195. In this embodiment, the horizontal longitudinal axes of tunnels 190, 195 are laterally offset (i.e., the longitudinal axis of tunnel 190 lies in a vertical plane that is horizontally spaced from a vertical plane containing the longitudinal axis of tunnel 195), however, tunnels 190, 195 partially laterally overlap with one another (i.e., a vertical plane oriented parallel to the longitudinal axes of tunnels 190, 195 can be positioned such that it intersects and passes through both tunnels 190, 195).

[0023] Conduits 183, 184 connect tunnels 190, 195. One conduit 183 provides a passage for a supply line 182 that extends from lower tunnel 195 to upper tunnel 190. Conduit 183 preferably has a diameter preferably between 6.0 and 12.0 in., and more preferably 7.0 in. The other conduit 184 provides a passage for a drillstring 110 that extends from upper tunnel 190 to lower tunnel 195. Conduit 184 preferably has a diameter between 12.0 and 24.0 in., and more preferably 20.0 in.

[0024] Drilling site 100 also includes a drilling system 103 and a local drilling fluids circulation system 130. As will be described in more detail below, circulation system 130 is an automated, sealed/gas-tight system that circulates drilling fluid through drilling system 103 during drilling operations while controlling the pressure and flow rate of the circulating drilling fluid.

[0025] Referring still to Figure 2, drilling system 103 includes a drilling rig 104 in upper tunnel 190, a drillstring 110 suspended from rig 104, and a blowout preventer (BOP) 111 in lower tunnel 195. Drillstring 110 extends from rig 104 through conduit 184 and BOP 111. Drillstring 110 includes a plurality of drill pipe joints 112 connected together end-to-end, a bottom hole assembly (BHA) 113, and a drill bit 114. BHA 113 is coupled to the lowermost pipe joint 112, and drill bit 114 is connected to the lower end of BHA 113.

[0026] During drilling operations, drill bit 114 is rotated with rig 104 and/or a downhole motor in BHA 113 and weight-on-bit (WOB) is applied to enable bit 114 to drill a borehole 105 extending downward from lower tunnel 195 through formation 101. The upper portion of borehole 105 is lined with casing 115. BOP 111 is mounted to a wellhead disposed at the upper end of casing 115. An annulus 106a is formed in borehole 105 between drillstring 110 and casing 115, and between drillstring 110 and the sidewall of borehole 105. In addition, an annulus 106b is formed inside BOP 111 about drillstring 110. Annuli 106a, 106b are contiguous and in fluid communication.

[0027] Referring still to Figure 2, during drilling operations, mud circulation system 130 supplies clean, processed drilling fluid to drilling system 103 and receives dirty, used drilling fluid from drilling system 103. For purposes of clarity and further explanation, the clean, processed drilling fluid or mud pumped down drillstring 110 is designated with reference numeral 121, and the dirty, used drilling fluid or mud returned from borehole 105 via annuli 106a, 106b is designated with reference numeral 121'. During drilling operations, the clean, processed drilling fluid 121 is pumped down drillstring 110, through the face of bit 114, and returns to the surface 104 via annuli 106a, 106b. While being circulated through borehole 105, solids (e.g., formation cuttings), liquids (e.g., hydrocarbons, water, etc.), gases (e.g., hydrogen sulfide, natural gas, etc.), or combinations thereof become entrained in fluid 121, thereby transitioning clean fluid 121 into used drilling fluid 121'. As will be described in more detail below, mud circulation system 130 is a fully enclosed, sealed fluid circulation system that is controlled and automated by a control system 300 (Figure 4).

[0028] As best shown in Figures 1 and 2, a primary supply line 180 supplies processed drilling fluid 121 from central processing facility 200 to system 130 at drill site 100, and a primary return line 185 returns the partially processed, used drilling fluid 121' from system 130 at drill site 100 to central processing facility 200. As will be described in more detail below, in this

embodiment, used drilling fluid 121' is partially processed within local circulation system 130 to remove the relatively large, heavy solids entrained within used drilling fluid 121' before returning it to central processing facility 200 via return line 185.

[0029] Referring now to Figure 2, in this embodiment, drilling fluids circulation system 130 includes a drilling fluid supply tank or vessel 131, a supply pump 140, a surge tank 149, a solids control device 150, and a return pump 145. Primary supply line 180 supplies processed drilling fluid 121 from central processing facility 200 to tank 131, a first supply line 181 provides fluid communication between tank 131 and supply pump 140, and a second supply line 182 provides fluid communication between supply pump 140 and a rotatable drilling mud supply coupling 135 (e.g., swivel) mounted to the upper end of drillstring 110. As previously described, second supply line 182 extends from lower tunnel 195 through conduit 183 to upper tunnel 190.

[0030] Supply tank 131 has a drilling fluid inlet 131a coupled to primary supply line 180 and a drilling fluid outlet 131b coupled to first supply line 181. Tank 131 is a fully enclosed, sealed, pressurized vessel that provides a reservoir for storing a suitable quantity of processed drilling fluid 121 locally at drilling site 100. For well control purposes, tank 131 preferably stores a volume of drilling fluid 121 greater than or equal to the volume of borehole 105, and more preferably about three times the volume of borehole 105. Storage of such a volume of drilling fluid 121 at drill site 100 enables system 130 to rapidly respond to immediate demands for drilling fluid 121 (e.g., such as may be desired during a well control event). It should also be appreciated that primary supply line 180 extending from central processing facility 200 to tank 131 effectively stores an additional volume of drilling fluid 121.

[0031] Supply pump 140 has a drilling fluid inlet 140a coupled to first supply line 181 and a drilling fluid outlet 140b coupled to second supply line 182. Second supply line 182 passes through supply conduit 183 and extends into upper tunnel 190. In addition, supply coupling 135 has an inlet 135a coupled to second supply line 182 and an outlet 135b in fluid communication with drillstring 110. As previously described, drillstring 110 extends from rig 104 in upper tunnel 190 through conduit 184 and BOP 111 into borehole 105. Thus, supply pump 140 pumps clean, processed drilling fluid 121 from tank 131 down drillstring 110 via supply lines 181, 182 and coupling 135. Supply pump 140 also facilitates the flow of clean, processed drilling fluid from central processing facility 200 into tank 131 via supply lines 180, 181.

[0032] Referring still to Figure 2, a first return line 186 provides fluid communication between a rotating head 136 mounted to the upper end of BOP 111 and surge tank 149; a second return line 187 provides fluid communication between surge tank 149 and solids control device 150; a third return line 188 provides fluid communication between solids control device 150 and return pump 145; and primary return line 185 returns partially processed, used drilling fluid 121' from return pump 145 to central processing facility 200.

[0033] Rotating head 136 is a fully enclosed, sealed, pressure containment coupling having a drilling fluid inlet 136a in fluid communication with annuli 106a, 106b and an outlet 136b coupled to first return line 186. Surge tank or vessel 149 has a drilling fluid inlet 149a coupled to first return line 186 and an outlet 149b coupled to second return line 187. Surge vessel 149 is a fully enclosed, sealed, pressurized vessel that includes a solids conditioning system that continuously agitates drilling fluid 121' therein to maintain a relatively homogenous, stable slurry. Solids control device 150 has a drilling fluid inlet 150a coupled to second return line 187 and an outlet 150b coupled to third return line 188. As will be described in more detail below, in this embodiment, used drilling fluid 121' is partially processed within solids control device 150 to separate and remove relatively large solids (e.g., large formation cuttings) from used drilling fluid 121'. Return pump 145 has an inlet 145a coupled to third return line 188 and an outlet 145b coupled to primary return line 185. Thus, return pump 145 pumps used drilling fluid 121' from annuli 106a, 106b to surge tank 149 and solids control device 150 via rotating control head 136 and return lines 186, 187. Return pump 145 also pumps the partially processed used drilling fluid 121' from solids control device 150 to central processing facility 200 via return lines 185, 188.

[0034] In this embodiment, each component and conduit of local drilling fluid circulation system 130 is fully enclosed, sealed and gas-tight to prevent any gas entrained within drilling fluid 121, 121' from escaping system 130 into tunnels 190, 195. In general, each pump 140, 145 can be any suitable pump known in the art including, without limitation, a duplex pump, a triplex pump, a positive displacement pump, or the like.

[0035] Referring now to Figure 3, solids control device 150 of circulation system 130 is shown. As previously described, device 150 receives used drilling fluid 121' via inlet 150a, separates relatively large solids from used drilling fluid 121', and returns the partially processed used drilling fluid 121' to central processing facility 200 via outlet 150b, return lines 188, 185, and

return pump 145. For purposes of clarity and further explanation, the relatively large solids removed from used drilling fluid 121' by device 150 are designated with reference numeral 122. In this embodiment, device 150 removes relatively large solids 122 but does not remove relatively small solids, liquids, or gases from used drilling fluid 121'. Removal of the relatively large solids 122 from drilling fluid 121' at drill site 100 offers the potential to enhance the durability and operating lifetime of return pump 145. In other embodiments, solids control device 150 can be removed/eliminated from the system provided return pump 145 can reliably handle the pumping of unprocessed used drilling fluid 121' returned from annulus 106a, 106b.

[0036] In this embodiment, device 150 is a sealed, gas-tight, pressurized containment vessel that includes an outer containment body or housing 151, a baffle or weir 160 disposed within housing 151, and a ramp 170 disposed within housing 151 below baffle 160. Housing 151 has an inner chamber or cavity 152, an inlet end 151a including inlet 150a, an outlet end 151b opposite end 151a and including outlet 150b, a top 151c, and a bottom 151d. Outlet 150b is positioned below inlet 150a. A vent line 153 in fluid communication with chamber 152 extends from top 151c of housing 151 proximal outlet end 151b. Vent line 153 includes a pressure-relief safety valve 154 to prevent over-pressurization of housing 151, which may otherwise rupture or damage device 150. Valve 154 is normally closed, thereby preventing fluid communication between chamber 152 and lower tunnel 195, but automatically transitions open at a predetermined pressure differential between chamber 152 and lower tunnel 195 to relieve pressure within housing 151. In addition, housing 151 includes a solids clean-out port 155 between bottom 151d and outlet end 151b. As will be described in more detail below, port 155 provides access to the relatively large solids 122 separated from used drilling fluid 121' within device 150. In this embodiment, port 155 is closed and sealed with a cap 156 that can be removed periodically to clean out separated solids from device 150. With valve 154 closed and cap 156 closing port 155, chamber 152 is sealed from lower tunnel 195, thereby preventing fluids entrained in used drilling fluid 121' from escaping into lower tunnel 195 at drilling site 100.

[0037] Referring still to Figure 3, baffle 160 is positioned within chamber 152 between top 151c and bottom 151d. Baffle 160 has a first or upstream end 160a proximal, but spaced apart from inlet 150a, a second or downstream end 160b adjacent outlet 150b, and an upper surface 161 extending between ends 160a, b. Surface 161 slopes downward moving from upstream end 160a to downstream end 160b, and thus, surface 161 may be described as being "sloped." Ramp 170

is positioned along bottom 151d of housing 151 and has a first or upstream end 170a proximal inlet 150a, a second or downstream end 170b proximal clean out port 155, and an upper surface 171 extending between ends 170a, b. Surface 171 slopes downward moving from upstream end 170a to downstream end 170b, and thus, surface 171 may be described as being “sloped.”

[0038] During drilling operations, used drilling fluid 121' flows into housing 151 via inlet 150a. Within housing 151, baffle 160 promotes the separation of the relatively large and heavy solids 122 from used drilling fluid 121'. In particular, baffle 160 divides chamber 152 into a first or upper portion 152a positioned above baffle 160 and inlet 150a, and a second or lower portion 152b positioned below baffle 160 and inlet 150a. As used drilling fluid 121' flows into chamber 152 from inlet 150a, the relatively large and heavy solids 122 in used drilling fluid 121' fall under the force of gravity into lower portion 152b below baffle 160 and move along sloped upper surface 171 of ramp 170 toward port 155, whereas the remainder of used drilling fluid 121' (including entrained gases, liquids, and relatively small/light solids) passes over baffle 160 through upper portion 152a and outlet 150b to return pump 145. In other embodiments, jetting rings may be used in the lower portion 152b to assist in solids removal.

[0039] In the manner described, relatively large solids 122 in used drilling fluid 121' are separated and captured in lower portion 152b of chamber 152, while the remainder of used drilling fluid 121' flows through upper portion 152a of chamber 152 and exits device 150 through outlet 150b. Although solids control device 150 employs baffle 160 to separate solids 122 from used drilling fluid 121' in this embodiment, in other embodiments, the solids control device 150 can utilize other types of solids separation technologies such as cyclonic separation technologies, etc.

[0040] Referring now to Figures 2 and 3, the removal of solids 122 from device 150 is preferably automated and includes the removal of cap 156 to clean out the solids captured in lower portion 152b, as well as the transport of solids 122 via a conveyor, conveyor belt, or similar system from lower tunnel 195 and drill site 100 to another location (e.g., the surface). The removed solids may be disposed of (e.g., transported to an appropriate disposal site), ground up and added to drilling fluid 121, etc. In addition, solids 122 are preferably removed from device 150 without human intervention, interrupting the flow of drilling fluid 121, 121' through systems 103, 130, and while maintaining the operating pressures within systems 103, 130. For example, multiple solids control devices 150 can be provided in system 130 to enable the

periodic cleanout of solids 122 from one device 150 while system 130 continues to circulate drilling fluid 121' through another device 150. In such embodiments, a switch is provided in return line 187 to automatically direct used drilling fluid 121' to flow to one or both devices 150 as desired. To remove the solids 122 from one device 150, the switch directs drilling fluid 121' to the second device 150, allowing drilling fluid 121' to continue to flow through the first device 150 and pressures to be maintained in system 130, while solids 122 are removed from the first device 150. And to remove solids 122 from the second device 150, the switch directs the flow of drilling fluid to the first device 150, allowing drilling fluid 121' to continue to flow through the second device 150 and pressures to be maintained in system 130, while solids 122 are removed from the second device 150.

[0041] Although system 130 includes solids control device 150 in this embodiment, in other embodiments, solids control device 150 can be removed/eliminated from system 130, thereby eliminating the need to manage separated solids at drill site 100. In one such embodiment, surge tank 149 agitates the used drilling fluid 121' to produce a sufficiently homogenous stable slurry that return pump 145 can reliably handle and pump to central processing facility 200. In another such embodiment, a device for grinding solids in used drilling fluid 121' is provided upstream of return pump 145 to crush and pulverize solids in used drilling fluid 121' to a sufficiently small size that they have little to no effect on the operation or reliability of return pump 145.

[0042] Referring now to Figures 2 and 4, in this embodiment, a control system 300 is provided to automate, operate, and control mud circulation system 130. System 300 is disposed locally in upper and lower tunnels 190, 195, respectively, but communicates with a remote drilling center 350 and central processing facility 200, each disposed at the surface 102. In this embodiment, system 300 includes instrumentation packages 301, 302, 303, 304, 305, a control module 306, and pumps 140, 145. Control module 306 is coupled to packages 301, 302, 303, 304, 305, pumps 140, 145, drilling center 350, and central processing facility 200, thereby enabling communications therebetween. In general, couplings and communications between packages 301, 302, 303, 304, 305, pumps 140, 145, drilling center 350, and central processing facility 200 can be wireless and/or wired. Further, although control module 306 is schematically shown in Figure 2 adjacent surge tank 149, in general, control module 306 can be positioned at any desired location (e.g., in tunnel 190, in tunnel 195, at the surface 102, etc.).

[0043] Instrumentation packages 301, 302, 303, 304, 305 measure and communicate data to control module 306. In particular, instrumentation package 301 measures the pressure and flow rate of drilling fluid 121 entering drillstring 110 at inlet 135a; instrumentation package 302 measures the pressure and flow rate of drilling fluid 121' at outlet 136b; instrumentation package 303 measures the pressure, flow rate, and level of drilling fluid 121' in solids control device 150; instrumentation package 304 measures the flow rate of drilling fluid 121 passing through pump 140 and the inlet and outlet pressures of pump 140; and instrumentation package 305 measures the flow rate of drilling fluid 121' passing through pump 145 and the inlet and outlet pressures of pump 145. In other embodiments, instrumentation package 303 can also include a gas detection system for detecting and monitoring gases (e.g., natural gas and/or hydrogen sulfide) entrained in the used drilling fluid 121' within solids control device 150.

[0044] As will be described in more detail below with reference to Figure 5, the measured data from instrumentation packages 301, 302, 303, 304, 305 is communicated to control module 306, which in turn communicates the measured data to drilling center 350. Desired operating parameters for circulation system 130 are communicated from drilling center 350 to module 306 and/or stored within control module 306. Based on a comparison of the measured data from packages 301, 302, 303, 304, 305 and the desired operating parameters for circulation system 130, control module 306 determines whether any adjustments to the flow rate of drilling fluid 121, the flow rate of drilling fluid 121', the pressure of drilling fluid 121, the pressure of drilling fluid 121', the weight of drilling fluid 121 supplied by central processing facility 200, or combinations thereof is necessary to achieve/maintain the desired operating parameters for circulation system 130. If adjustments are necessary, control module 306 sends a control command to pump 140, pump 145, central processing facility 200, or combinations thereof to adjust the flow rate of drilling fluid 121, the flow rate of drilling fluid 121', the pressure of drilling fluid 121, the pressure of drilling fluid 121', the weight of drilling fluid 121 supplied by central processing facility 200, or combinations thereof.

[0045] Referring now to Figure 5, a method 400 for automating, operating, and controlling drilling fluid circulation system 130 with control system 300 during drilling operations is shown. Starting in blocks 401, 402 of method 400, the pressures and flow rates of drilling fluids 121, 121' are continuously measured with instrumentation packages 301, 302, respectively, and the pressure, flow rate, and fluid level of drilling fluid 121' in solids control device 150 are

continuously measured with instrumentation package 303. In block 403, the flow rates of drilling fluids 121, 121' and the inlet and outlet fluid pressures of pumps 140, 145, respectively, are continuously measured with instrumentation packages 304, 305, respectively. Next, in block 404 of method 400, the data measured in blocks 401, 402, 403 by packages 301, 302, 303, 304, 305 is communicated to control module 306. In addition, the desired operating conditions for mud circulation system 130 are determined in block 406 and communicated to control module 306. The desired operating conditions can be communicated/updated as desired from drilling center 350 and/or stored in control module 306.

[0046] In embodiments described herein, balanced or slightly overbalanced drilling is preferred. Thus, the desired operating conditions are determined in block 406 to ensure that balanced or slightly overbalanced drilling is achieved while operating within the limitations of the equipment in systems 103, 130. In balanced or slightly overbalanced drilling, the pressure of drilling fluid 121, 121' at the bottom of borehole 105 is equal to or slightly greater than the formation pressure. In general, the formation pressure as a function of depth is generally known prior to drilling, and the pressure of drilling fluid 121, 121' at the bottom of borehole 105 is a function of the hydrostatic pressure of drilling fluid 121, 121' (i.e., weight of the fluid column in borehole 105), the fluid pressure of drilling fluid 121 pumped through inlet 135a, and the pressure of drilling fluid 121' exiting outlet 136b. Thus, the desired operating conditions include the desired pressure of drilling fluid 121, 121' at the bottom of borehole 105 or the parameters necessary to achieve the desired pressure of drilling fluid 121, 121' at the bottom of borehole 105 based on the formation pressure (i.e., mud weight, pressure of drilling fluid 121 at inlet 135a, pressure of drilling fluid 121' at outlet 136b, etc.). In this embodiment, the desired operating conditions also include, without limitation, desired flow rate ranges for drilling fluid 121 supplied to drillstring 110; desired flow rate ranges for drilling fluid 121' exiting rotating head 136; desired pressure, flow rate, and fluid level ranges for drilling fluid 121' in solids control device 150; desired operating speed, flow rate, inlet and outlet pressure ranges for pumps 140, 145.

[0047] Referring still to Figure 5, in block 405 of method 400, control module 306 determines the pressure of drilling fluid 121, 121' at the bottom of borehole 105 from the measured data provided by packages 301, 302, 303, 304, 305. In block 407, control module 306 compares the actual pressure of drilling fluid 121, 121' at the bottom of borehole 105 to the desired drilling fluid pressure at the bottom of borehole 105, and compares the measured data from blocks 401,

402, 403 to the desired operating conditions from block 406. Based on these comparisons, control module 306 determines if circulation system 130 is operating at the desired operating conditions according to block 408. If system 130 is not operating at the desired operating conditions, then control module 306 sends control commands to pump 140, pump 145, central processing facility 200, or combinations thereof to adjust the operation of pump 140, pump 145, the weight of drilling fluid 121 (via central processing facility 200), or combinations thereof to achieve the desired operating conditions in system 130 according to block 409. Control module 306 continues to adjust the operation of pump 140, pump 145, the weight of drilling fluid 121, or combinations thereof until the desired operating conditions of system 130 are obtained. Once system 130 is operating at the desired operating conditions, then control module 306 maintains the current operation of pumps 140, 145 and weight of drilling fluid 121 according to block 410.

[0048] System 300 can operate and control drilling fluid circulation system 130 on its own while drilling center 350 monitors the operation of systems 130, 300. However, as desired, control commands can be sent to control module 306 from drilling center 350 to adjust the desired operating conditions of system 130 and/or directly control the operation of pumps 140, 145 and the weight of drilling fluid 121 supplied by central processing facility 200.

[0049] In the manner described, control system 300 and control method 400 enable the automated control and operation of drilling fluid circulation system 130, while ensuring balanced or slightly overbalanced drilling. Method 400 and system 300 provide a process flow-based approach to drilling fluid circulation and management that offers the potential for a high degree of automation and enhanced well pressure control without direct human intervention as compared to the hydrostatically controlled atmospheric processing approach known in the art, which typically requires a relatively high degree of manual intervention.

[0050] Referring now to Figures 2 and 6, primary return line 185 supplies partially processed drilling fluid 121' from local circulation system 130 to central processing facility 200. Within central processing facility 200, the partially processed drilling fluid 121' is further processed to remove gases and the remaining solids in used drilling fluid 121'. Such processing of used drilling fluid 121' within central processing facility 200 converts it into clean, processed drilling fluid 121. Primary supply line 180 supplies clean, processed drilling fluid 121 from central processing facility 200 to local circulation system 130.

[0051] Referring now to Figure 6, central processing facility 200 includes a variety of components for processing used drilling fluid 121' and converting it into clean drilling fluid 121. In this embodiment, central processing facility 200 includes a degasser 210 for removing gases from drilling fluid 121', solids separation equipment 220 for removing solids from drilling fluid 121', and a drilling fluid transfer pump 250 for facilitating the flow of drilling fluid 121' through facility 200, as well as facilitating the exchange of drilling fluid 121, 121' with local circulation system 130. Primary return line 185 provides fluid communication between local circulation system 130 and degasser 210, a first flow line or conduit 225 provides fluid communication between degasser 210 and solids separation equipment 220, a second flow line or conduit 245 provides fluid communication between solids separation equipment 220 and transfer pump 250, and primary supply line 180 provides fluid communication between transfer pump 250 and local circulation system 130. The central processing facility 200 can also include a local storage vessel or tank for storing clean, processed drilling fluid 121.

[0052] Degasser 210 has a drilling fluid inlet 210a coupled to primary return line 185, a drilling fluid outlet 210b coupled to first flow line 225, and a gas outlet 210c. Within degasser 210, gases (e.g., hydrogen sulfide, hydrocarbon gases, etc.) are removed from partially processed drilling fluid 121'. The separated gases exit degasser 210 via outlet 210c and the drilling fluid 121' exits degasser 210 via outlet 210b. In this embodiment, the separated gas flowing through outlet 210c is not vented, but rather, is collected in a gas storage tank or vessel 211 coupled to outlet 210c. The gas captured in vessel 211 can be safely transported away from processing facility 200, further processed, used, or flared as desired. The drilling fluid 121' with gas removed flows from degasser 210 through outlet 210b and first flow line 225 to solids separation equipment 220. In general, degasser 210 can comprise any degasser known in the art for removing gas from drilling fluid.

[0053] Solids separation equipment 220 receives drilling fluid 121' from degasser 210, and as previously described, removes solids from drilling fluid 121'. In general, solids separation equipment 220 can comprise any hardware or equipment known in the art for separating solids from drilling fluid. In this embodiment, solids separation equipment 220 comprises a shaker 221, a desander 230, and a desilter 240, which remove progressively smaller solids.

[0054] Shaker 221 has a drilling fluid inlet 221a coupled to first flow line 225, a drilling fluid outlet 221b, and a solids outlet 221c. Within shaker 221, vibrating screens catch relatively large

and medium solids not previously removed by solids control device 150, while allowing the remaining drilling fluid 121' to fall therethrough. The separated solids exit shaker 221 via outlet 221c and the remaining drilling fluid 121' exits shaker 221 via outlet 221b and flows to desander 230. The removed solids are captured and stored in a storage vessel 222 that can be periodically cleaned out. In general, shaker 221 can comprise any suitable shaker known in the art.

[0055] Desander 230 has a drilling fluid inlet 230a coupled to outlet 221b, a drilling fluid outlet 230b, and a solids outlet 230c. Within desander 230, a hydrocyclone removes sand and relatively small solids from drilling fluid 121' not previously removed by solids control device 150 or shaker 221, while allowing the remaining drilling fluid 121' to flow therethrough. The separated solids exit desander 230 via outlet 230c and the remaining drilling fluid 121' exits desander 230 via outlet 230b and flows to desilter 240. The removed solids are captured and stored in a storage vessel 232 that can be periodically cleaned out. In general, desander 230 can comprise any suitable desander known in the art.

[0056] Desilter 240 has a drilling fluid inlet 240a coupled to outlet 230b, a drilling fluid outlet 240b coupled to second flow line 245, and a solids outlet 240c. Within desilter 240, a hydrocyclone removes relatively small solids and silt from drilling fluid 121' not previously removed by solids control device 150, shaker 221, or desander 230. Following removal of gases in degasser 210, and removal of large, medium, and small solids in device 150, shaker 221, desander 230, and desilter 240, used drilling fluid 121' is converted into clean, processed drilling fluid 121. The separated solids exit desilter 240 via outlet 240c and the clean, processed drilling fluid 121 exits desilter 240 via outlet 240b and flows through second flow line 245 to transfer pump 250, which pumps processed drilling fluid 121 through primary supply line 180 to local circulation system 130. The removed solids are captured and stored in a storage vessel 242 that can be periodically cleaned out. In general, desilter 240 can comprise any suitable desilter known in the art.

[0057] Although the exchange of partially processed drilling fluid 121' and processed drilling fluid 121 has been described in the context of one drilling site 100 and central processing facility 200, both drilling sites 100 operate in the same manner, and as shown in Figure 1, both drilling sites 100 exchange partially processed drilling fluid 121' and processed drilling fluid 121 with the same central processing facility 200. For example, in this embodiment, a primary return line 185 supplies partially processed drilling fluid 121' from a local circulation system (e.g., mud

circulation system 130) at second drilling site 100 to central processing facility 200, and more specifically, a transfer pump 250 and a primary supply line 180 supply clean, processed drilling fluid 121 from central processing facility 200 to the local circulation system at second drilling site 100.

[0058] In this embodiment, each component and conduit of central processing facility 200 is sealed and gas-tight to prevent any gas entrained within drilling fluid 121, 121' from escaping facility 200 into the surrounding environment. This may be particularly advantageous when site facility 200 is located in an environmentally sensitive area or when facility 200 is located in a confined space such as an underground tunnel.

[0059] In this embodiment, central processing facility 200 converts partially processed drilling fluid 121' to clean drilling fluid 121 by removing gases and solids from drilling fluid 121'. However, in other embodiments, the central processing facility (e.g., central processing facility 200) also adjusts the composition and chemistry of the drilling fluid (e.g., drilling fluid 121'). For example, in such other embodiments, water or other liquid may be added to the drilling fluid, and/or one or more chemical additives may be added to the drilling fluid to adjust the drilling fluid weight, pH, and/or viscosity. Furthermore, in other embodiments, the components of the central processing facility may be arranged in a different order, one or more components may be removed from the central processing facility, one or more components (e.g., poor boy degasser, vacuum degasser, mud cleaner, decanter centrifuge, etc.) may be added to the central processing facility, or combinations thereof.

[0060] Used drilling fluid 121' and processed drilling fluid 121 flow through system 10 between local circulation system(s) 130 and central processing facility 200. However, all drilling fluid 121, 121' is completely contained within system 10 as it is circulated within drilling sites 100, within central processing facility 200, and between drilling sites 100 and central processing facility 200. Accordingly, system 10 may be described as being a sealed and enclosed system. In addition, as previously described, local circulation system(s) 130 and central processing facility 200 are each sealed and gas-tight during normal drilling operations, thereby preventing the dissociation and release of gases and liquids entrained in drilling fluids 121, 121' to the surrounding environment(s). As a result, system 10 is particularly well-suited for use in connection with drilling sites (e.g., drilling sites 100) where relatively high levels of hydrogen

sulfide (H₂S) gas may be encountered, well sites in environmentally sensitive areas, and well sites located within a confined space (e.g., underground tunnel).

[0061] System 10 can be used in relatively cold environments, but in such environments, the various containment vessels in local circulation systems 130 and central processing facility are preferably insulated and/or heated (e.g., with a heat coil) to prevent the drilling fluid from freezing. In general, any heating device known in the art may be used to prevent the drilling fluid from freezing including, without limitation, a steam generator with a glycol circulation system. Although drill site 100 of system 10 is a subterranean drill site, in general, embodiments described herein can be used in connection with above ground and below ground drilling sites.

[0062] While preferred embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the invention. For example, the relative dimensions of various parts, the materials from which the various parts are made, and other parameters can be varied. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

CLAIMS

What is claimed is:

1. A closed loop drilling fluids circulation system comprising:
 - a first drilling fluid circulation system disposed at a first subterranean drill site, wherein the first drilling fluid circulation system includes a supply tank for holding clean drilling fluid and a solids control device configured to separate solids from used drilling fluid; and
 - a central processing facility disposed at a location remote from the first drill site and configured to receive used drilling fluid from the solids control device and supply clean drilling fluid to the supply tank.
2. The system of claim 1, wherein the central processing facility comprises a degasser configured to remove gas from the used drilling fluid, solids separation equipment configured to remove solids from the used drilling fluid, and a transfer pump configured to pump clean drilling fluid to the supply tank.
3. The system of claim 1, wherein the first drilling fluid circulation system is a sealed and pressurized system.
4. The system of claim 3, wherein the first drilling fluid circulation system further comprises:
 - a return pump configured to pump used drilling fluid from the solids control device to the central processing facility; and
 - a supply pump configured to pump clean drilling fluid from the supply tank down a drillstring.
5. The system of claim 4, wherein the return pump is configured to pump used drilling fluid from an annulus in a borehole to the solids control device.
6. The system of claim 3, wherein the solids control device comprises:
 - a housing having an inner chamber, a first end including an inlet, and a second end including an outlet;

a baffle disposed in the inner chamber, the baffle having an upstream end proximal the inlet, a downstream end proximal the outlet, and an upper surface extending from the upstream end to the downstream end;

wherein the upper surface is positioned vertically above the inlet at the upstream end.

7. The system of claim 6, wherein the baffle divides the inner chamber of the solids control device into an upper portion disposed above the baffle and a lower portion disposed below the baffle;

wherein the upper portion is configured to allow the flow of used drilling fluid from the inlet to the outlet and the lower portion is configured to collect solids separated from the used drilling fluid.

8. The system of claim 7, wherein the housing includes a solids-cleanout port for removing solids from the lower portion.

9. The system of claim 3, wherein the first drilling fluid circulation system further comprises:

a surge vessel upstream of the solids control device and configured to agitate the used drilling fluid.

10. The system of claim 4, wherein the central processing facility includes a gas-tight degasser configured to remove gas from the used drilling fluid.

11. The system of claim 10, wherein the degasser has an inlet for receiving used drilling fluid from the return pump, a drilling fluid outlet, and a gas outlet in sealed fluid communication with a gas storage vessel.

12. The system of claim 1, further comprising:

a second drilling fluid circulation system disposed at a second subterranean drill site, wherein the second drilling fluid circulation system includes a supply tank for holding clean drilling fluid and a solids control device configured to separate solids from used drilling fluid;

wherein the central processing facility is configured to receive used drilling fluid from the solids control device of the second drilling fluid circulation system and supply clean drilling fluid to the storage vessel of the second drilling fluid circulation system.

13. A drilling fluids circulation system disposed at a drill site, the system comprising:
 - a pressurized storage vessel for holding clean drilling fluid at the drill site;
 - a supply pump configured to pump clean drilling fluid from the pressurized storage vessel down a drill string;
 - a pressurized surge vessel configured to receive and hold used drilling fluid from an annulus disposed about the drill string;
 - a sealed and pressurized solids control device configured to receive used drilling fluid from the surge vessel and separate solids from used drilling fluid; and
 - a return pump configured to pump used drilling fluid from the solids control device.
14. The system of claim 13, wherein the solids control device has an inlet in fluid communication with the surge vessel, an outlet in fluid communication with the return pump, and a solids cleanout port.
15. The system of claim 13, further comprising:
 - a central processing facility configured to receive used drilling fluid from the return pump, convert the used drilling fluid into clean drilling fluid, and supply clean drilling fluid to the inlet of the storage vessel.
16. The system of claim 13, wherein the storage vessel has a storage volume equal to or greater than the volume of a borehole disposed about the drill string.
17. The system of claim 13, wherein the drill site is disposed below ground.
18. The system of claim 13, further comprising:
 - an instrumentation package for measuring the pressure of the clean drilling fluid pumped down the drill string;

an instrumentation package for measuring the pressure of the used drilling fluid exiting the annulus;

a control module configured to automatically adjust the weight of the clean drilling fluid and the operation of the return and supply pumps based on the measured pressures of the of the clean drilling fluid pumped down the drill string and the pressure of the used drilling fluid exiting the annulus.

19. A method for circulating and processing drilling fluid, the method comprising:

- (a) receiving used drilling fluid from a borehole at a first subterranean drill site;
- (b) preventing the escape of gases from the used drilling fluid at the first subterranean drill site;
- (c) pumping the used drilling fluid from the first subterranean drill site to a central processing facility disposed at the surface after (b);
- (d) processing the used drilling fluid to form clean drilling fluid at the central processing facility; and
- (e) pumping the clean drilling fluid from the central processing facility to the first subterranean drill site after (d).

20. The method of claim 19, further comprising separating at least some solids from the used drilling fluid at the first subterranean drill site.

21. The method of claim 19, further comprising:

- drilling a borehole at the first subterranean drill site with a drillstring;
- pumping clean drilling fluid from a pressurized supply tank at the first subterranean drill site down the drill string; and
- storing a volume of clean drilling fluid in the supply tank that is equal to or greater than the volume of the borehole.

22. The method of claim 21, further comprising:

- maintaining a pressure of the drilling fluid at a bottom of the borehole substantially equal to a formation pressure.

23. The method of claim 22, further comprising:
flowing used drilling fluid from an annulus in the borehole;
measuring a pressure of the drilling fluid pumped down the drill string;
measuring a pressure of the drilling fluid flowing from the annulus;
adjusting the pressure of the drilling fluid pumped down the drill string or the pressure of the drilling fluid pumped from the annulus to maintain the pressure of the drilling fluid at a bottom of the borehole substantially equal to the formation pressure.
24. The method of claim 19, wherein (d) comprises:
(d1) removing gases from the used drilling fluid; and
(d2) preventing the escape of the removed gases into the surrounding environment at the central processing facility.
25. The method of claim 19, further comprising:
flowing used drilling fluid from the borehole into a pressurized surge tank; and
pumping used drilling fluid from the surge tank to the solids control device.

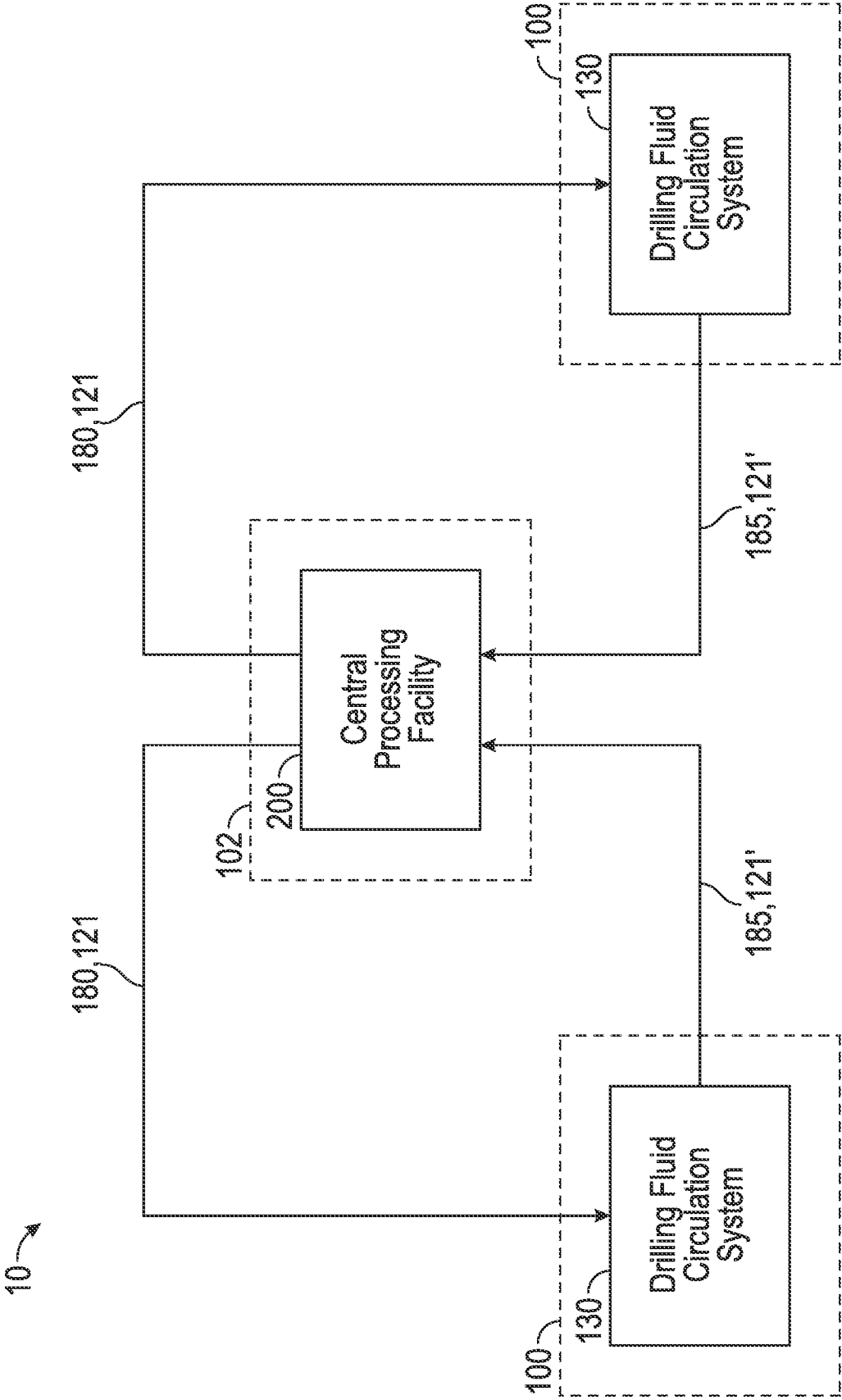
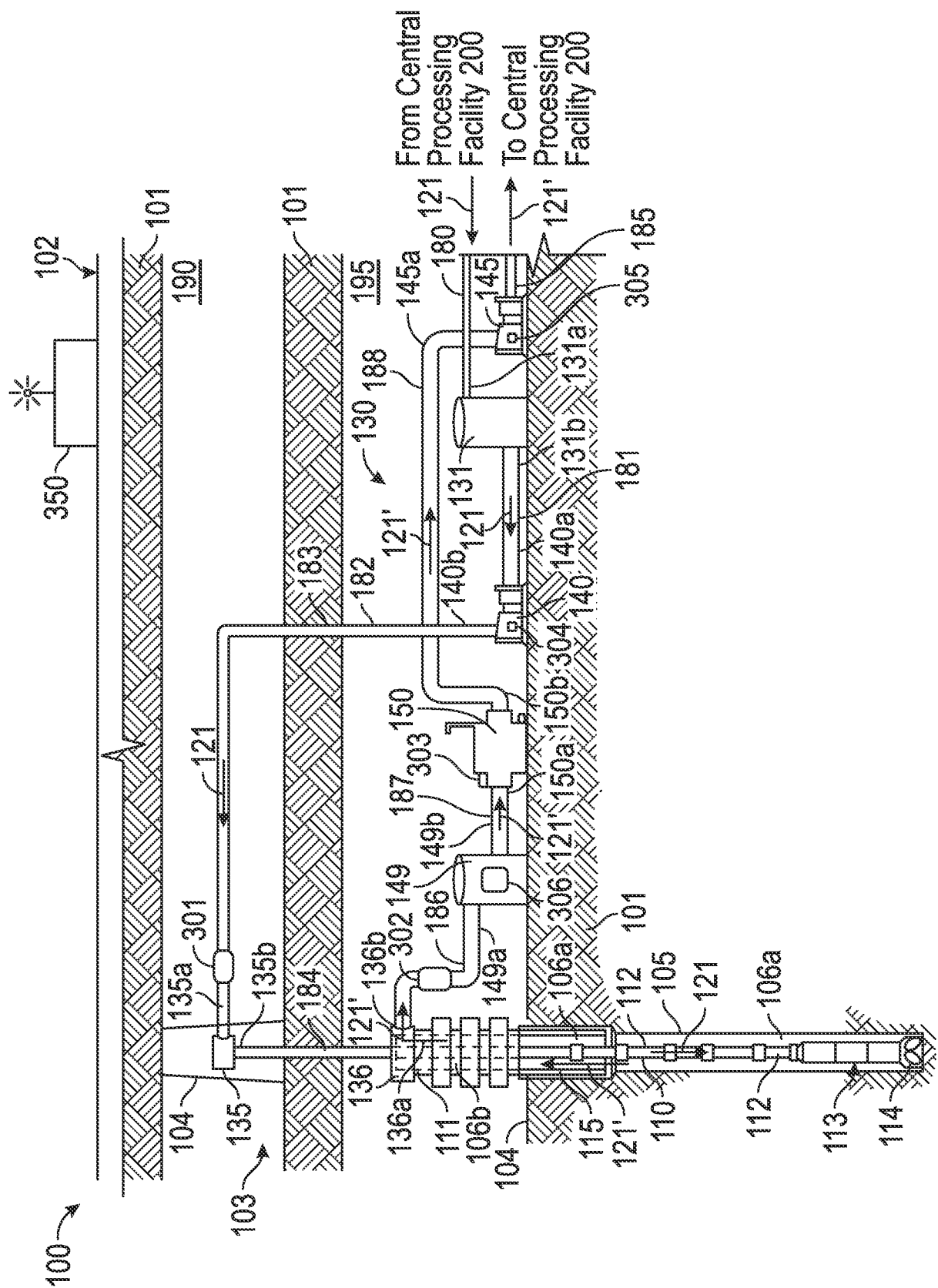


FIG. 1



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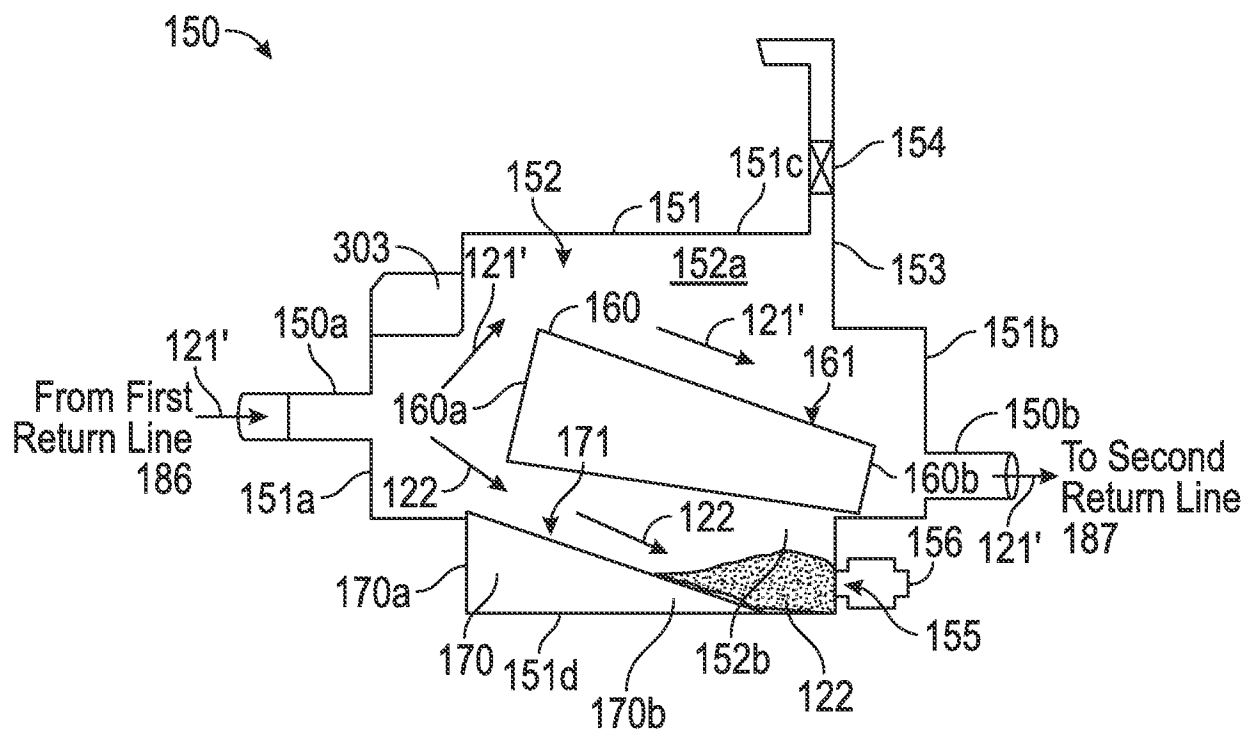


FIG. 3

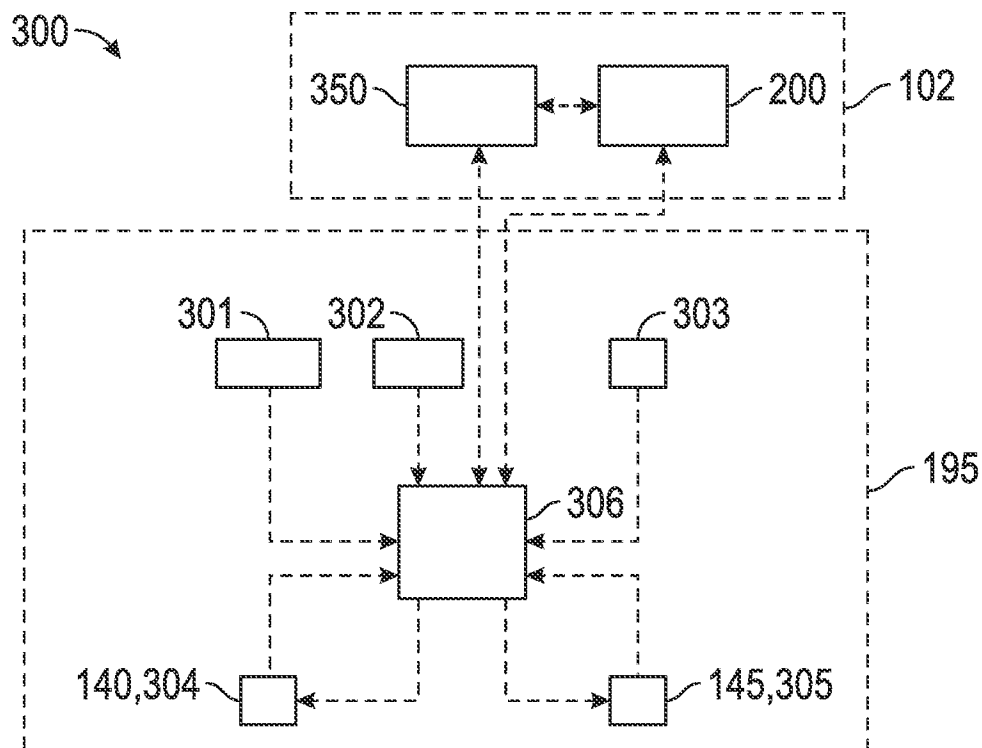


FIG. 4

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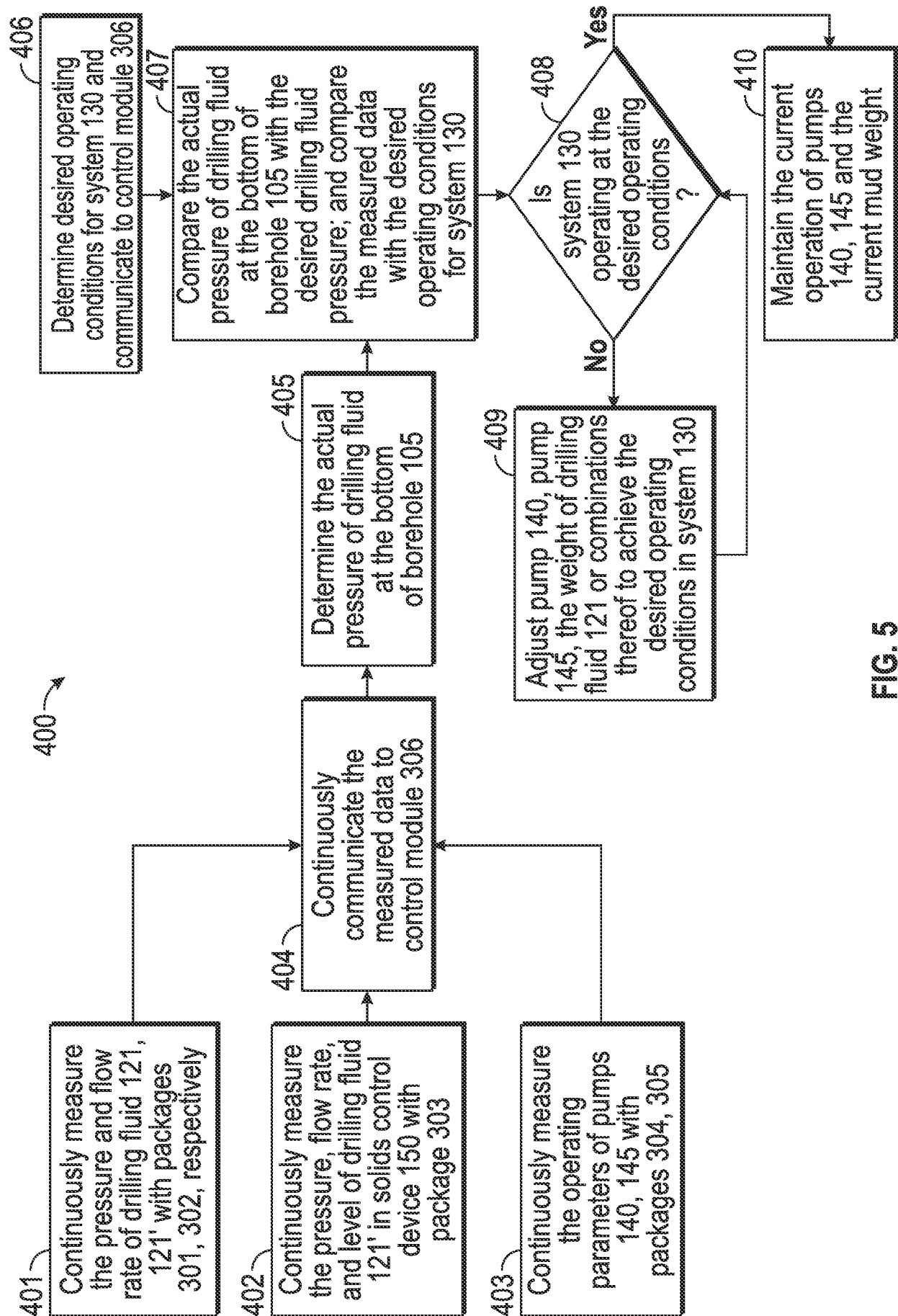


FIG. 5

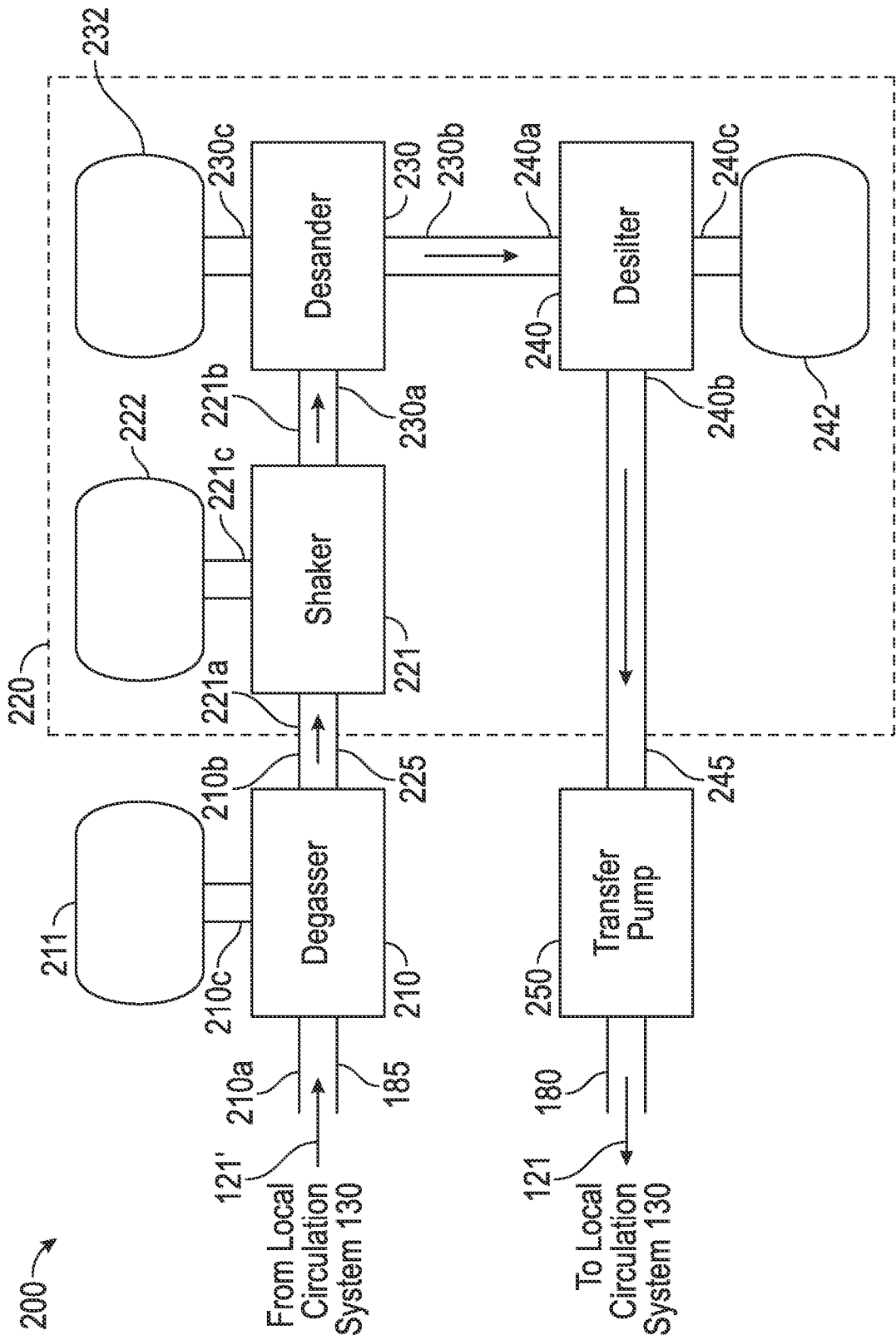


FIG. 6