



(22) Date de dépôt/Filing Date: 2008/06/19

(41) Mise à la disp. pub./Open to Public Insp.: 2009/02/28

(45) Date de délivrance/Issue Date: 2011/09/20

(30) Priorité/Priority: 2007/08/30 (US11/847,904)

(51) Cl.Int./Int.Cl. *E21B 21/08* (2006.01),
E21B 47/06 (2006.01), *E21B 47/12* (2006.01)

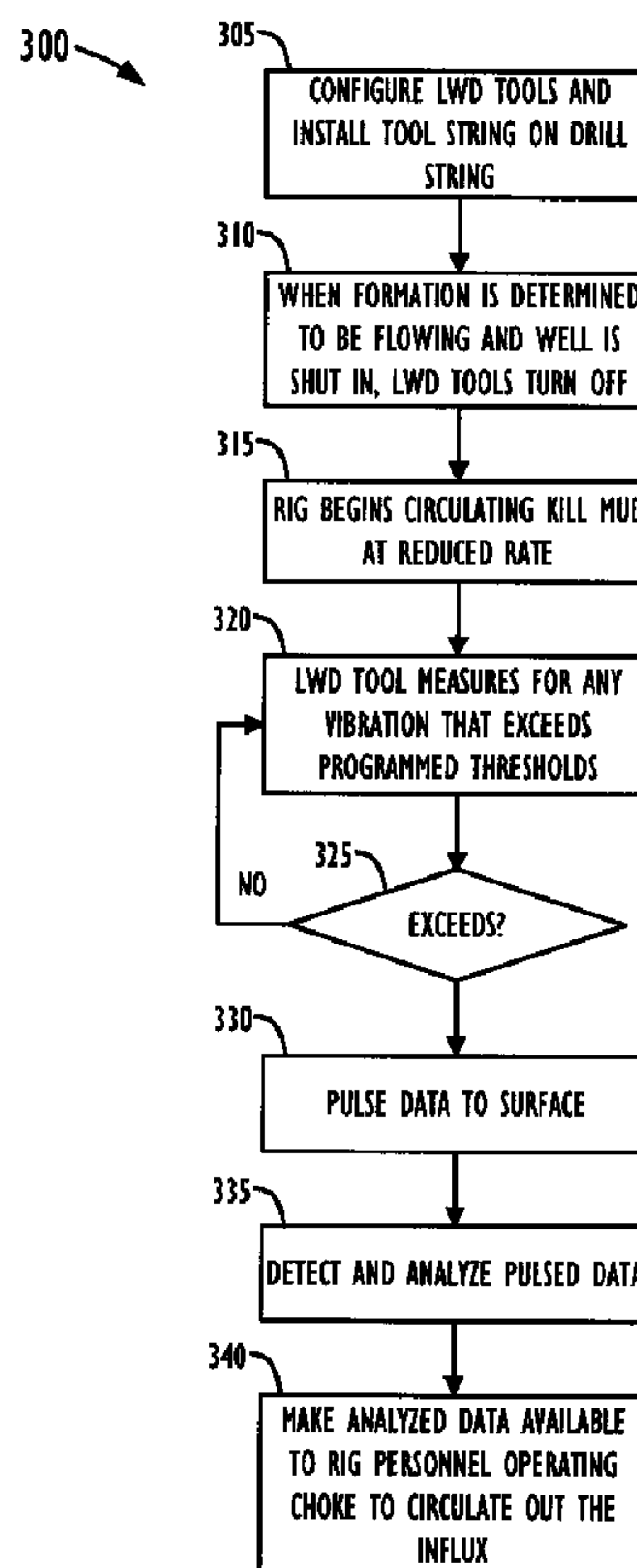
(72) Inventeurs/Inventors:
SCHNEIDER, BARRY, US;
CHEATHAM, CURTIS, US;
MAULDIN, CHARLES, US

(73) Propriétaire/Owner:
PRECISION ENERGY SERVICES INC., US

(74) Agent: GOODWIN MCKAY

(54) Titre : SYSTEME ET METHODE PERMETTANT D'OBTENIR ET D'UTILISER DES DONNEES DE FOND DE TROU
PENDANT DES OPERATIONS DE CONTROLE DE PUITS

(54) Title: SYSTEM AND METHOD FOR OBTAINING AND USING DOWNHOLE DATA DURING WELL CONTROL
OPERATIONS



(57) Abrégé/Abstract:

In a well control system and method, a tool driver on a toolstring is configured to activate a telemetry tool in response to a predetermined threshold of accelerometer data measured by an accelerometer. For example, the predetermined accelerometer

(57) **Abrégé(suite)/Abstract(continued):**

data threshold preferably corresponds to an acceleration level expected while drilling mud is being pumped at a slow pump rate of a well control operation through the drill pipe of the well. When a fluid influx occurs during drilling, the well is shut-in so that the tool driver turns off the telemetry tool. The drill pipe and casing pressures of the shut-in well are obtained. Then, drilling mud having a first weight is pumped into the drill pipe at a slow mud pump rate. Because the tool driver is set to activate the telemetry tool in response to accelerometer data at the slow pump rate, the telemetry tool begins sending downhole pressure data to the surface. In this way, rig operations can change the mud weight and adjust the choke line during the kill operation based on an analysis of the downhole pressure data obtained during the well control operation.

ABSTRACT

1
2
3 In a well control system and method, a tool driver on a toolstring is
4 configured to activate a telemetry tool in response to a predetermined threshold of
5 accelerometer data measured by an accelerometer. For example, the predetermined
6 accelerometer data threshold preferably corresponds to an acceleration level expected
7 while drilling mud is being pumped at a slow pump rate of a well control operation
8 through the drill pipe of the well. When a fluid influx occurs during drilling, the well is
9 shut-in so that the tool driver turns off the telemetry tool. The drill pipe and casing
10 pressures of the shut-in well are obtained. Then, drilling mud having a first weight is
11 pumped into the drill pipe at a slow mud pump rate. Because the tool driver is set to
12 activate the telemetry tool in response to accelerometer data at the slow pump rate, the
13 telemetry tool begins sending downhole pressure data to the surface. In this way, rig
14 operations can change the mud weight and adjust the choke line during the kill operation
15 based on an analysis of the downhole pressure data obtained during the well control
16 operation.

1 **SYSTEM AND METHOD FOR OBTAINING AND USING DOWNHOLE DATA**
2 **DURING WELL CONTROL OPERATIONS**

3

4 **FIELD OF THE DISCLOSURE**

5 The subject matter of the present disclosure generally relates to well
6 control operations for oil and gas wells and more particularly relates to a system and
7 method for obtaining and using downhole data during well control operations.

8

9 **BACKGROUND OF THE DISCLOSURE**

10 FIG. 1A illustrates a typical prior art drilling system. During drilling,
11 drilling fluid ("mud") is pumped by mud pumps 40 through the drill string 30, drill bit
12 32, and back to the surface through the annulus 14 between drill string 30 and the
13 wellbore 10. While drilling, it is known in the art to use an accelerometer on a tool
14 string downhole to measure tool shock and drilling vibration. This information can alert
15 rig operators when harmful downhole vibrations are occurring that will require a
16 changing in the drilling operation. In addition, it is known in the art to measure
17 pressures and temperatures downhole and to relay the measured data to the surface using
18 pressure modulated telemetry techniques. In such prior art implementations, pulsing of
19 any measured data to the surface is not begun until the accelerometer measures a value
20 that at least exceeds certain set thresholds or a pressure transducer samples data above a
21 preset threshold.

22 To control the hydrostatic pressure of fluids in the formation 16
23 penetrated by the wellbore 10, the density of the drilling mud is controlled by various
24 weighting agents known in the art. The weight of this mud often is controlled to prevent
25 loss of well control or blowout. For example, a mud weight that exceeds the fracture

1 strength of the exposed portion of the formation 16 below the casing 12 in the wellbore
2 10 can fracture the formation 16 and cause mud to be lost, and potentially result in loss
3 of well control.

4 Alternatively, a mud weight that falls below the pore pressure of exposed
5 portion of the formation 16 can allow an influx of fluid to occur in the wellbore 10. For
6 example, a zone may be encountered in the formation 16 that has a higher pore pressure
7 than the wellbore fluid pressure applied by the mud. This causes a “kick” or influx of
8 formation fluid (liquid, gas, or both) into the wellbore 10 that can be detrimental to the
9 operation. When such a kick occurs, rig operators perform well control operations to
10 circulate the influx of formation fluid out of the wellbore 10 and regain control of the
11 wellbore pressure for drilling.

12 Because the influx of formation fluid (liquid and/or gas) reduces the
13 density of the drilling fluid in the wellbore annulus 14, the kick can be detected by
14 evidencing a change in pressure in the wellbore annulus 14 or a change in mud density in
15 the wellbore annulus 14, the kick can be detected by a gain in drilling fluid volume in the
16 tanks or pits 42 for the mud system. When the kick is detected, rig operators then
17 implement a well control operation to circulate the influx of formation fluids out of the
18 wellbore 10 and regain control of the well again.

19 Two well control operations are widely used in the oil and gas industry to
20 regain control after a kick. A first method is called the Wait & Weight (or Engineer’s)
21 method, while the second method is called the Driller’s method. When a kick is detected
22 in both methods, rig operators initially stop the mud circulation, shut-in the wellbore 10
23 using the blow-out preventer (BOP) 20, and measure the pressure buildup in the wellbore
24 annulus 14, gain in the mud tanks 42, and shut-in pressure of the drill pipe 30.
25 Calculations are then made to determine a kill weight of mud that has a high enough

1 density to produce hydrostatic pressure at the point of influx in the wellbore 10 that will
2 stop the flow of formation fluid into the wellbore 10.

3 Both the Engineer's and the Driller's methods have their advantages and
4 disadvantages, and the choice of one method over the other may depend on various
5 considerations, including operator preference as well as the circumstances involved in a
6 particular well control situation such as the volume of the kick, the margin between the
7 mud weight in the annulus 14 when the kick is taken and the minimum fracture gradient
8 strength in the wellbore 10, and the increase required in mud weight to regain well
9 control. Advantages of the Engineer's method include: (1) in many cases, only one
10 circulation of the wellbore 10 is required to circulate out the kick and replace the original
11 weight mud with kill weight mud, which can save rig time, and (2) in many cases, the
12 maximum wellbore pressure at the last exposed casing shoe is less than the Driller's
13 method, thereby reducing chances of fracturing the openhole during well control, which
14 can require additional rig time to regain control. Advantages of the Driller's method
15 include: (1) the implementation of the method is more straightforward because one
16 circulation of the wellbore 10 is performed using the original weight mud to circulate out
17 the kick, and a second circulation of the wellbore 10 is preformed using kill weight mud
18 to regain well control, and (2) in some cases, the kick is circulated out of the wellbore 10
19 more quickly; for example, when significant time is required to increase the rig's active
20 mud system to the necessary kill weight mud.

21 As an example of one of the two common methods, FIG. 1B shows a flow
22 chart of the Engineer's method 100 according to the prior art. Although not shown in
23 this flow chart, slow pump rates of the mud pumps 40 and choke/kill line friction tests
24 are run at predetermined intervals during drilling prior to taking the kick. These slow
25 pump rates are typically one-half to one-third of the normal circulation rate of the pumps

1 40 while drilling new formation. These tests and measurements help determine the
2 frictional pressure losses created by flowing through the choke/kill line 50/60 for given
3 mud properties at several flow rates. The intention of making these measurements prior
4 to taking a kick is to be better prepared to implement well control operations should they
5 become necessary. For example, the data and measurements help to optimize the mud
6 flow rate during kill operations, with the goal of reducing the amount of time needed to
7 regain well control while taking special care not to exert too high or too low of a
8 pressure to the formation 16. While important in all drilling applications, these tests and
9 measurements area of even greater importance when drilling with a subsea BOP 20
10 where the choke and kill lines 50/60 may be up to 10,000-feet in length and may produce
11 more significant pressure losses in the choke and the kill lines, which greatly complicates
12 maintaining wellbore pressure within the desired limits during the well control
13 operations.

14 While drilling, a kick due to an influx of formation fluid (liquid, gas, or
15 any combination thereof) into the wellbore 10 may be detected (Block 105). The well is
16 shut-in by closing the BOP 20, and rig operators record the pressures at the surface on
17 the drill pipe 30 (Shut-In Drill Pipe Pressure SIDP) and the casing 12 (Shut-In Casing
18 Pressure SICP) using standard techniques (Block 110). The rig operators then fill out a
19 standard "kill" sheet to outline the procedures for circulating out the influx and regaining
20 well control (Block 115). As known in the art, the "kill" sheet is a spreadsheet or
21 worksheet on which rig operators pre-record information about slow pump pressures at
22 specific mud pump flow rates (psi @ SPM), choke line friction pressures at specific mud
23 pump flow rates (psi @ SPM), true pump output (linear diameter, stroke length, and
24 efficiency), drill string capacity and other details, annular capacity and other details, and
25 the casing 12 specifics such as inner diameter, burst pressure rating, and the depth of the

1 casing shoe Operators also input measurements such as Shut-in Drill Pipe Pressure
2 (SIDPP), Shut-In Casing Pressure (SICP), and Pit Gain. Using information and
3 calculations on the kill sheet, the rig operators can then determine the kill weight mud
4 (KWM), initial circulation pressure (ICP), final circulating pressure (FCP), maximum
5 allowable casing pressure (MCP), and pressure decline schedule for performing a well
6 control operation.

7 Using the calculated weight required for the mud to kill the influx, rig
8 operators “weight up” the active mud system by increasing the density of the drilling
9 mud in tanks 42 using known techniques (Block 120). Then, the rig operators circulate
10 the kill weight mud into the system by pumping it into the drill pipe 30 at a flow rate
11 determined from the kill sheet (Block 125).

12 During the pumping, the rig operators monitor the pressures at the
13 standpipe to ensure that the proper pressure is exerted on the formation 16 because
14 pumping too heavy of a mud at too high of a rate could damage the formation 16
15 whereas too low of a pressure could cause an additional influx. Once the mud reaches
16 the bit, the drill pipe pressure is recorded in order to adjust the choke 62 to keep the drill
17 pipe pressure constant while the kill weight mud is circulated up the wellbore 10 to the
18 surface.

19 Once a full circulation of kill weight mud has been pumped, the rig
20 operators shut off the pumps 40 and monitor for pressure build up on the drill pipe 30 or
21 the casing 12 (Block 135) and determine if there is a build up of pressure (Decision 140).
22 Such a build up of pressure on the drill pipe 30 or casing 12 after shut-in would indicate
23 that the influx has not been properly killed. If there is a build up, then the process must
24 be repeated by closing the BOP 20, recording pressures, recalculating information in the
25 kill sheet, etc. If there is no build up, then the uncontrolled flow of formation fluid into

1 the wellbore 10 has been stopped, and the rig operators can resume normal drilling
2 operations (Block 145).

3 In the Engineer's method described above as well as in the Driller's
4 method, rig operators control pressure on the casing 12 and/or drill pipe 30 by adjusting
5 the choke 62 that conducts the mud from the casing 12 to a mud reservoir (not shown)
6 and by operating the mud pumps 40 at previously measured slow circulating (kill) rates
7 and corresponding pressure. The length of the choke line 60 for a surface BOP stack is
8 generally short enough to neglect the frictional pressure loss through the choke line 60 at
9 the slow circulating rate. However, this is not the case for a subsea BOP, where the
10 choke line 60 is generally at least several hundred feet long. In deepwater, the choke line
11 60 is generally thousands of feet in length. Hence, the pressure losses through the choke
12 line 60 for subsea BOPs due to friction are significant even at slow circulating rates.

13 Therefore, to be prepared for well control, rig operators need to know
14 slow circulating rate pressures and the friction pressure drops through the choke line
15 (*i.e.*, choke line friction pressures). To determine slow circulating rate pressures, for
16 example, the rig operators pump drilling mud down the drill string 30 at various pump
17 speeds and allow the returns to pass through the riser. This process obtains the slow
18 circulating rate pressures used to calculate the initial circulation pressures (ICP) and final
19 circulating pressures (FCP) for the kill sheet.

20 Various techniques can be used to determine the choke line friction
21 pressures, such as by pumping at slow circulating rate pressures through the kill and
22 choke lines with the rams closed. Before drilling is commenced, for example, rig
23 operators can determine first slow circulating rate pressures from returns through the
24 riser. Then, rig operators can open the choke 62 fully and measure second slow
25 circulating pressures through the choke line 60. The choke line friction pressures at the

1 various pump rates are calculated as the difference between these two slow circulating
2 pressures. Regardless of how obtained, the choke line friction pressure must be adjusted
3 for changes in mud properties.

4 As those skilled in the art will appreciate, it is important that well control
5 operations be performed carefully. Operators attempting to control an influx may
6 damage the formation 16 by exerting too great of a pressure on the formation 16. Any
7 damage to the formation 16 can cause partial or complete loss of returns and can create
8 situations that will take considerable time and additional strings of casing 12 to regain
9 well control and return to normal drilling operations. In extreme cases, a substantial
10 portion of the openhole wellbore 10 may be abandoned, requiring redrilling.

11 In the Driller's method, the rig operators must adjust the choke 62 on the
12 choke line 60 to keep the casing pressure equal to the shut-in casing pressure minus the
13 choke line friction pressure while the kill mud is pumped down the drill pipe 30.
14 Because the bottom hole pressure is determined from the sum of the casing pressure at
15 the surface, the annular pressure, and the choke line friction pressure, the accuracy and
16 the reliability of pressure measurements and calculations can be particularly difficult to
17 obtain reliably on deepwater drilling rigs using subsea BOP stacks. Use of inaccurate
18 choke line friction pressures when circulating out a kick in such an implementation could
19 result in either an increase or decrease in the bottom hole pressure that could damage the
20 formation 16 or cause a secondary fluid influx.

21 Therefore, it is important that sound procedures be used to determine the
22 choke line friction pressures. Unfortunately, obtaining choke line friction pressures
23 periodically throughout the drilling process only provides for the mud properties at one
24 moment in time. Friction pressure losses in the choke line 60, annulus 14, bit 32, and
25 drillstring 30 vary significantly with changes in the mud properties such as density and

1 viscosity. During normal drilling operations, and especially after a kick is taken, the
2 mud properties can vary greatly based on factors such as mud weight, viscosity, and
3 oil/water ratios. Consequently, the friction pressure losses will also generally change
4 significantly when the original weight mud is weighted up to provide the kill weight
5 mud.

6 In addition to the above problems, prior art well control operations can be
7 time consuming and can require extensive planning, calculations, monitoring, and human
8 intervention to execute. Furthermore, current well control operations are not open to
9 much flexibility. As one example, the Engineer's method may require rig operators to
10 construct a graphical or tabular pumping schedule of pump pressure versus volume
11 pumped, and this pumping schedule must be followed by the rig operators during well
12 control. In another example, both the Engineer's and Driller's methods for well control
13 use substantially constant pump rates to maintain control while executing the operation,
14 which is not always ideal or achievable. In the event it becomes necessary to change
15 pumping rates and/or interrupt pumping during execution of the well control procedure,
16 it frequently may be necessary to record new shut-in pressures, new circulating
17 pressures, and recalculate an entirely new pumping and pressure schedule.

18 Not only do the prior art methods consume additional rig time and thereby
19 increase costs to the operator and risks to the well control operations, but they also
20 provide a less than optimal ability to determine accurate bottom hole pressure. As will
21 be appreciated, the combination of mud, formation cuttings, and influx fluid(s) in the
22 wellbore can vary significantly foot-by-foot and over time and can create uncertainty in
23 the determination of the actual wellbore pressure in the annulus. Moreover, obtaining
24 accurate choke line pressure losses poses another problem in determining the actual
25 wellbore pressure in the annulus. This problem with accurate choke line pressure losses

1 may be particularly acute on a subsea BOP and especially in deepwater, where the
2 effects of temperature and pressure can cause choke line friction pressures to be
3 significantly inaccurate.

4 Accordingly, systems and methods are needed that can facilitate well
5 control operations by giving rig operators real-time downhole data during a well control
6 operation to use when executing the operation. The subject matter of the present
7 disclosure is directed to overcoming, or at least reducing the effects of, one or more of
8 the problems set forth above.

9

10 **BRIEF DESCRIPTION OF THE DRAWINGS**

11 FIG. 1A illustrates a typical drilling system according to the prior art.

12 FIG. 1B illustrates a well control operation using a Engineer's Method
13 according to the prior art.

14 FIG. 2A illustrates a drilling system in accordance with one embodiment
15 of the present disclosure.

16 FIG. 2B illustrates a tool string having Logging While Drilling (LWD)
17 tools for use in well control operations according to certain teachings of the present
18 disclosure.

19 FIG. 2C illustrates one embodiment of a pulse modulated telemetry
20 module for the tool string of FIG. 2B.

21 FIG. 3A illustrates operation of the disclosed LWD tools during well
22 control operations according to certain teachings of the present disclosure.

23 FIGS. 3B-3C illustrate graphs of accelerometer data obtained during
24 operation of the disclosed LWD tools.

1 FIG. 4 illustrates a well control operation using the disclosed LWD tools
2 in accordance with one embodiment.

3 FIG. 5 illustrates another well control operation using the disclosed LWD
4 tools in accordance with another embodiment.

5

6 **DETAILED DESCRIPTION**

7 FIG. 2A illustrates a drilling system having a well control system 200
8 according to one embodiment of the present disclosure. The well control system 200
9 includes analysis tools 210, surface sensors 220, and Logging While Drilling (LWD)
10 tools 230. The analysis tools 210 include, but are not limited to, computers, software,
11 data acquisition devices, rig personnel, etc. The LWD tools 230 are part of a tool string
12 on the drill pipe 30 that can be used for standard logging or measuring while drilling and
13 that can also be used in well control operations according to certain teachings of the
14 present disclosure. Other elements of the drilling system shown are similar to the
15 standard components known in the art.

16 FIG 2B shows portion of the tool string having several LWD tools 230.
17 As shown, these tools 230 include a pressure modulated telemetry module 240, a battery
18 module 260, and a bore annular pressure module 270. In one embodiment, the LWD
19 tools 230 can be part of a hostile-environment logging (*HEL*) MWD system designed by
20 Weatherford International Ltd. for high-pressure/high-temperature hostile drilling
21 environments.

22 The battery module 260 provides power for the other tools 230. For
23 example, the battery module 260 may continuously power the bore annular pressure
24 module 270 to obtain pressure and temperature measurements. The bore annular
25 pressure module 270 has a bore pressure port, an annular pressure port, and quartz

1 transducers for obtaining pressure measurements as well as temperature measurements.
2 The pressure and temperature data can then be communicated to the surface using the
3 telemetry module 240, which uses mud flow and battery power to generate positive mud
4 pulses to send encoded information to the sensors 220 (See FIG. 2A) at the surface of the
5 well. In one embodiment, the telemetry module 240 can include a Pressure Modulated
6 Telemetry (PMT™) system available from Weatherford International Ltd.

7 The telemetry module 240 is not always turned on and active while
8 downhole. The module 240 is specifically intended to be shut off when the wellbore 10
9 is shut in so casing and drill pipe pressures can be obtained. As schematically shown in
10 FIG. 2C, the telemetry module 240 includes a driver 242 having a switching mechanism
11 250 that controls power from the battery module 260 to pressure modulated telemetry
12 components 244, which can include a pulser for example.

13 The switching mechanism 250 has an accelerometer 252 that is laterally
14 oriented in the module 240 and that is capable of monitoring vibrations while the tools
15 230 are downhole. The accelerometer 252 may be a piezoelectric based sensor, and it
16 may be similar to an Environmental Severity Measurement (ESM™) sensor available
17 from Weatherford International Ltd. Also, the accelerometer may be a capacitive
18 acceleration sensor or Micro-ElectroMechanical System (MEMS) type sensor.

19 Using the accelerometer 252, the switching mechanism 250 is designed to
20 detect vibrations in the tool string that indicate that fluid is flowing, the tool string is
21 rotating, and/or the power section (mud motor) is operating. In particular, the
22 accelerometer 252 responds to vibrations, accelerations, and the like while the tool string
23 30 is downhole. In response to measured data exceeding pre-set thresholds, the driver
24 242 activates the switching mechanism 250 to provide power to the telemetry
25 components 244. Once activated, the telemetry components 244 then begin transmitting

1 pressure and temperature data from the bore annular pressure module 270 to the surface
2 for detection by the sensors 220.

3 FIG. 3A illustrates a process 300 of operating the disclosed LWD tools
4 230 during a well control operation according to certain teachings of the present
5 disclosure. Initially, rig operators configure the LWD tools 230 and install the tool string
6 on the drill string 30 (Block 305). In configuring the LWD tools 230, rig operators
7 program the switching mechanism 250 of the driver 242 to turn the telemetry
8 components 244 on when vibration and/or pressure exceeds certain levels so that the
9 telemetry components 244 will begin pulsing data to the surface. In general, the levels
10 are determined based on particular details of a given implementation, such as the well
11 characteristics, pump rates, pressures, etc.

12 While drilling, a kick may be detected, and the well is shut in. At this
13 point, the LWD tools 230 turn off when the pumps 40 are turned off so that rig operators
14 can observe any shut-in build up pressures in the drill pipe 30 or casing 12 (Block 310).
15 The rig operators perform the necessary well control calculations, weight up the required
16 kill weight mud, and begin to circulate the kill weight mud down the drill pipe 30 at a
17 reduced flow rate to kill the influx (Block 315).

18 Downhole, the accelerometer 252 measures vibrations that occur from
19 fluid flowing through the drill pipe 30 while the mud is pumped (Block 320), and the
20 driver 242 determines whether the measured data exceeds a predetermined threshold
21 programmed in the module 240 (Decision 325). Once the measured data exceeds the set
22 threshold, the switching mechanism 250 activates the telemetry components 244 to begin
23 pulsing measured pressure and temperature data from the bore annular pressure module
24 270 to the surface (Block 330). Even if the driver 242 has a pressure sensor (not shown)
25 capable of activating the telemetry components 244, the pressure levels caused by

1 drilling mud being pumped at the slow pump rate would be too low for the pressure
2 sensor to achieve activation during the well control operation. Therefore, it is preferred
3 to use the accelerometer 252 to measure vibrations to achieve activation of the telemetry
4 components 244.

5 Encoding software known in the art for pulse telemetry can be used in the
6 module 240 to send the measured data to the surface via encoded pressure waves in the
7 fluid of the wellbore 10. The encoding may be based on combinatorial or other
8 techniques. At the surface, sensors 220 detect the pulsed data, which may constitute
9 positive pressure pulses of less than about 15-psi to about 4-psi. Using decoding
10 software, the analysis tools 210 decode and analyze the detected data (Block 335). For
11 example, the surface sensors 220 can be multiple pressure transducers placed throughout
12 the standpipe manifold and gooseneck of the rig to detect the encoded pressure waves.

13 It will be appreciated that the ability to acquire the pulsed data during the
14 low flow from the slow pump rates of the well control operation can depend on the
15 particular flow rate used, such as the orifice selection, and other implementation-specific
16 details. Drilling noise and pipe rotation will typically be absent during the well control
17 operation so signal noise from these sources will likely not inhibit detection of pulsed
18 data at the surface. Although the lower pump pressure may inhibit the ability to detect
19 the pulsed data, the mode or frequency for pulsing the data with the telemetry module
20 240 can be changed as needed. For example, to assist detection, a greater pump on time
21 could be used while designing the backup mode. In another example, a downlink unit
22 (not shown) known in the art can be used to switch what frequencies are used for the
23 pulsed data at the module 240 without needing to cycle the pumps. In addition, the
24 program in the telemetry module 240 may only send the pressure data (to determine the

1 equivalent circulating density (ECD) of the mud) and the temperature data to simplify
2 what encoded data would need to be detected and decoded at the surface.

3 At the surface, the analysis tools 210 can include a computer using
4 software to identify and decode the detected data. During analysis, the analysis tools 210
5 correct the pressure data for depth downhole and convert the corrected pressure data to
6 local mud weight units. Ultimately, the analyzed, real-time data is made available to rig
7 operators operating the chokes 52/62 on the kill and choke lines 50/60 and attempting to
8 circulate out the influx with the kill weight mud (Block 340). The real-time data
9 measured downhole with the tools 230 automatically accounts for any variations and
10 inconsistencies in the properties of the kill weight mud being pumped downhole. In this
11 way, the analyzed data offers the rig operators substantially more accurate information
12 for conducting the well control operation.

13 In one advantage, for example, the real-time data enables the rig operators
14 to verify and correct choke and kill line friction pressures during the well control
15 operation so they can more effectively operate the chokes 52/62 and maintain a more
16 constant and consistent pressure at the bottom of the wellbore 10 while performing the
17 operation. In other advantages, the real-time data allows the well control operators to
18 make timely decisions regarding the well control operation and can reduce the potential
19 for non-productive time and improve the safety of well control operation. In yet another
20 advantage, the real-time data can assist rig operators in performing both the Driller's and
21 Engineer's methods. By increasing the accuracy of the data used in the Engineer's
22 method, rig operators can actually decide at the time of a kick whether to use either the
23 Driller's method or the Engineer's method.

24 As noted above (in Block 305), the switching mechanism 250 is
25 programmed to control the telemetry components 244 in response to measured

1 accelerometer data. More particularly, the switching mechanism 250 activates the
2 telemetry components 244 to begin transmitting real-time telemetry data in response to
3 measured accelerometer data resulting from fluid pumped through the tool string at the
4 slow mud pump rates of a well control operation. Likewise, the mechanism 250
5 deactivates the components 244 when there is substantially no flow through the tool
6 string. Before activating the telemetry components 244, the mechanism 250 preferably
7 determines that vibrations have been sustained above a predetermined activation
8 threshold for a predetermined amount of time. Conversely, before deactivating the
9 telemetry components 244, the mechanism 250 preferably determines that the vibrations
10 have been sustained below a predetermined deactivation threshold for a predetermined
11 amount of time. The activation and deactivation thresholds may be the same, but the
12 activation threshold is preferably set higher to prevent erratic starts and stops of data
13 transmission caused by false signals.

14 To help illustrate how the switching mechanism 250 is configured to
15 operate, reference now turns to exemplary graphs in FIGS. 3B-3C. The graph 350, in
16 FIG. 3B, shows raw vibration measured by the accelerometer (252) during a portion of
17 operation. Initially, there is no flow through the pipe due to shut-in after a kick has been
18 detected. The pumps are then turned on to pump mud at a slow pump rate through the
19 drill string during a well control operation. This flow of mud through the tool string
20 causes vibration, and the accelerometer (252) measures the vibration. The measured
21 accelerometer data may be sampled at any suitable sampling rate, such as 16-Hz, 32-Hz,
22 64-Hz, 128-Hz, etc. but the sampling rate is preferably at least 32-Hz or greater. Once
23 the pumps are turned off after the mud has been pumped, the vibrations subside.

24 Preferably, the accelerometer (252) used in the switching mechanism
25 (250) is a capacitive acceleration sensor or Micro-ElectroMechanical System (MEMS)

1 type sensor. Because this type of accelerometer is sensitive to DC acceleration, the DC
 2 offset caused by the accelerometer's orientation is preferably removed. To remove the
 3 offset, the difference (delta) between the acceleration from sample to sample are
 4 compared to produce resulting AC acceleration.

5 The graph in FIG. 3C shows the AC acceleration (in mg's) resulting from
 6 obtaining the differences from sample to sample in the data of FIG.3B. As shown, the
 7 activation and deactivation thresholds are preferably set as low as possible to enable
 8 detection of low flow through the tool string expected during the slow pump rates of a
 9 well control operation. However, the thresholds are not set so low as to be triggered by
 10 thermal noise and other disruptions in the accelerometer data. Preferably, both of the
 11 thresholds are at least below 20-mg, but the thresholds are directionally proportional to
 12 the sampling rate used for obtaining the data. The Table below provides exemplary
 13 threshold values for various sampling rates.

Sampling Rate	Deactivation Threshold	Activation Threshold
16-Hz	1.22 mg	1.53 mg
32-Hz	2.44 mg	3.06 mg
64-Hz	4.88 mg	6.12 mg
128-Hz	9.76 mg	12.24 mg

14
 15 As mentioned previously, the switching mechanism (250) preferably
 16 focuses on sustained periods of data to determining whether to activate or deactivate
 17 telemetry during operation. To do this, the switching mechanism (250) can use an
 18 accumulator to count how many times the acceleration is greater than the activation
 19 threshold or less than the deactivation threshold in recurring periods of 1-second or so.
 20 By focusing on the number of consecutive results of the accumulator over a period of
 21 time, the switching mechanism (250) can thereby detect sustained levels of vibration

1 (flow) or sustained periods of no vibration (no flow) to ensure proper
2 activation/deactivation of the telemetry components (244). As shown in FIG. 3C, this
3 accumulation technique produces a delay period (*e.g.*, 5-seconds) from the time the
4 pumps are turned on before telemetry is activated and another delay period (*e.g.*, 5-
5 seconds) from the time the pumps are turned off before telemetry is deactivated.

6 In the above example, the accelerometer data used by the switching
7 mechanism (250) to determine whether to activate/deactivate the telemetry components
8 (244) is related to AC acceleration from sample to sample. In addition to this form of
9 data, however, the switching mechanism (250) may use other forms of data from the
10 accelerometer (252) such as raw acceleration, pipe acceleration, time, etc. With respect
11 to these other forms of accelerometer data, the driver 242 can be programmed to detect
12 variances in these forms of data caused by low flow from the slow pump rates used in a
13 well control operation so that the switching mechanism 250 can respond accordingly and
14 activate/deactivate the telemetry components 244 during the operation.

15 With an understanding of the disclosed LWD tools 230, their
16 configuration, and operation, we now turn to a discussion of well control operations
17 using the disclosed LWD tools 230.

18 FIG. 4 illustrates a well control operation 400 using the disclosed LWD
19 tools 230 based on the wait and weight or Engineer's method of performing a kill
20 operation. The operation 400 essentially starts out with standard procedures. For
21 example, the well is determined to be flowing due to an influx of fluid from the
22 formation 16 (Block 405), and the rig operators shut-in the well and record the pressures
23 of the drill pipe 30 and the casing 12 (Block 410). Next, the rig operators start the
24 standard "kill" sheet to outline the procedure for controlling the influx in the wellbore 10
25 (Block 415) and begin weighting up the active system based on the determined weight

1 required for the mud to kill the influx (Block 420). Finally, the rig operators begin
2 circulating the kill weight mud into the system by bringing the mud pumps 40 up to a kill
3 operation speed (slow pump rate) determined by the choke line frictions and the kill
4 sheet (Block 425).

5 As noted previously, the LWD tools 230 have a switching mechanism 250
6 configured to turn on the telemetry module 240 when downhole vibrations exceed a
7 predetermined low vibration threshold so that the telemetry module 240 can be activated
8 at the low flow rate during the kill operation to measure downhole data. Turning on the
9 telemetry module 240 in this manner represents one area where the present operation 400
10 diverges from standard procedures in the art that do not activate tools at low flow rates to
11 make such measurements during a kill operation.

12 In the present operation 400, the bore annular pressure module 270
13 measures pressure data that is to determine the static equivalent mud weight (EMW), and
14 the pulsed telemetry module 240 sends the measured pressure data to the surface where
15 the analysis tools 210 determine the maximum static EMW (Block 430). Then, the
16 maximum static EMW is compared to the pressure readings for the drill pipe 30 and
17 casing 12 obtained using standard techniques (Block 435). Based on the comparison,
18 analysis determines the correct mud weight to use for the kill operation, and the rig
19 operators commence the kill operations using that correct kill weight mud (Block 440).
20 At this point if desirable, rig operators may also select what method (*i.e.*, Driller's or
21 Engineer's method) to proceed with.

22 Continuing with the kill operation, the bore annular pressure module 270
23 obtains pressure data while the kill weight mud is pumped into the drill pipe 30. All the
24 while, the telemetry module 240 sends the measured pressure data to the surface, and the
25 rig operators monitor the pressure data to ensure that the equivalent circulating density

1 (ECD) of the mud downhole remains at desired levels while the kill weight mud is
2 pumped (Block 445). As is known, the equivalent circulating density (ECD) refers to the
3 effective density of the mud being circulated and exerted against the formation 16. If the
4 ECD does not remain at a desired level while the kill weight mud is pumped, then rig
5 operators can adjust the variable choke 62 as necessary. Typically, the rig operators use
6 the variable choke 62 to maintain the casing pressure constant at a value equal to the
7 shut-in casing pressure minus the choke line friction pressure while the kill weight mud
8 is pumped down the drill pipe 30. When the mud reaches the bit, the rig operators
9 typically use the variable choke 62 to keep the drill pipe pressure constant until the kill
10 weight mud is pumped up the wellbore 10 to the surface. Having real-time information
11 about the equivalent circulating density (ECD) helps the rig operators handle these
12 pressure control procedures while pumping the kill weight mud whose properties may
13 vary due to the various factors discussed previously.

14 Even though the rig operators are taking action to kill the influx with the
15 kill operation, it is not uncommon during a kill operation to have to stop, make
16 recalculations, and start over again at this point due to faulty assumptions or unknown
17 variables. In general, the kill operation assumes that the kick is caused by an influx of
18 liquid so that the kill operation relies on a liquid model. In a worst case, however, the
19 kick may actually be caused by an influx of gas, which is harder to model. Accordingly,
20 the rig operators use calculations based on liquid model assumptions, which may not
21 adequately account for the actual properties of the influx encountered. Using the LWD
22 tools 230 to obtain real-time downhole pressure data during the low flow rates of the kill
23 operation, however, may reduce the likelihood that the rig operators would have to stop
24 and do a reiteration of various steps in the kill operation. In essence, obtaining the
25 downhole pressure data eliminates some of the uncertainties associated with assuming

1 that the kill pressure is linearly correlated to the mud weight as is the case with the liquid
2 model.

3 Once a full circulation of kill weight mud has been pumped into the drill
4 pipe 30 and up the wellbore 10 to the surface, the rig operators shut the pumps 40 off and
5 monitor the well for pressure build up on the drill pipe 30 or the casing 12 (Block 450).
6 If there is pressure build up (Decision 455), the operation 400 must be repeated because
7 the kill weight mud was of insufficient weight to hydrostatically balance the formation.
8 Otherwise, the uncontrolled flow has been stopped, and the rig operators can resume
9 normal drilling operations (Block 460).

10 FIG. 5 illustrates a well control operation 500 using the disclosed LWD
11 tools 230 based on the Engineer's method of performing a kill operation. Again, the
12 operation 500 essentially starts out with standard procedures, such as determining that
13 the well is flowing due to an influx (Block 505), shutting-in the well to record drill pipe
14 30 and casing 12 pressures (Block 510), and starting the standard "kill" sheet (Block
15 515). In contrast to the Driller's method, the rig operations at this point bring the mud
16 pumps 40 up to kill operations speed as before but pump the existing weight of mud that
17 was being used before the influx was detected (Block 520).

18 Using the telemetry module 240 configured to turn on in response to
19 vibration levels exceeding predetermined thresholds (*See* FIG. 3A), the maximum static
20 EMW from pressures measured with the LWD tools 230 is recorded (Block 525) and is
21 compared to the previously measured pressure data of the drill pipe 30 and casing 12
22 (Block 530). Based on the comparison, analysis determines the correct mud weight to
23 use for the kill operation (Block 535). At this point, the rig operators begin weighting up
24 the active system and commence the kill operation by pumping the kill weight mud into
25 the drill pipe 30 (Block 540). While the kill weight mud is pumped at the low flow rate,

1 the bore annular pressure module 270 makes pressure readings that the rig operators
2 monitor to ensure that the equivalent circulating density (ECD) of the mud remains at
3 desired levels (Block 545). If the ECD does not remain at a desired level while the kill
4 weight mud is pumped, then rig operators can adjust the variable choke 62 as necessary.

5 Once a full circulation of kill weight mud has been pumped into the drill
6 pipe 30 and back up to the surface through the wellbore 10, the rig operators shut the
7 pumps 40 off and monitor the well for pressure build up on the drill pipe 30 or on the
8 casing 12 (Block 550). If there is pressure build up (Decision 555), the operation 500
9 must be repeated because the kill weight mud was of insufficient weight to
10 hydrostatically balance the formation. Otherwise, the uncontrolled flow was stopped,
11 and the rig operators can resume normal operations (Block 560).

12 While the present disclosure focuses on well control operations, the
13 teachings of the present disclosure can be used in other reduced flow situations in a well,
14 such as testing situations of a formation, situations where circulation is lost, situations
15 where returns lost to the formation are experienced, or any other situation in which
16 logging while drilling data may be useful but the pump rates must be reduced from any
17 normally planned drilling speeds. In the lost return situation, for example, operators
18 typically flow at slow pump rates in an attempt to pump and spot pills across trouble
19 zones in the formation. By ultimately supplying accurate pressure data in such a
20 situation, one cause of non-productive time in deepwater can be reduced by the disclosed
21 teachings.

22 The foregoing description of preferred and other embodiments is not
23 intended to limit or restrict the scope or applicability of the inventive concepts conceived
24 of by the Applicants. In exchange for disclosing the inventive concepts contained herein,
25 the Applicants desire all patent rights afforded by the appended claims. Therefore, it is

1 intended that the appended claims include all modifications and alterations to the full
2 extent that they come within the scope of the following claims or the equivalents thereof.
3

1 **WHAT IS CLAIMED IS:**

2

3 1. A well control method, comprising:

4 configuring a telemetry tool on a drill pipe in a well to activate in response to
5 a predetermined threshold associated with accelerometer data;

6 shutting-in the well in response to a fluid influx during drilling;

7 stopping telemetry of downhole pressure data via drilling fluid by turning off
8 the telemetry tool;

9 obtaining drill pipe and casing pressures of the shut-in well while telemetry is
10 stopped;

11 pumping drilling mud having a first weight into the drill pipe at a first mud
12 pump rate, the first mud pump rate being used in a well control operation to kill the fluid
13 influx and being slower than a normal mud pump rate used during drilling;

14 sending downhole pressure data uphole via drilling fluid by activating the
15 telemetry tool in response to accelerometer data at least reaching the predetermined
16 accelerometer data threshold induced by the drilling mud pumped at the first mud pump
17 rate;

18 determining a static equivalent mud weight from the downhole pressure data;

19 comparing the static equivalent mud weight to the drill pipe and casing
20 pressures; and

21 changing the first weight for the drilling mud to a second weight when
22 indicated by the comparison.

23

1 2. The method of claim 1 wherein the act of configuring comprises
2 selecting the predetermined accelerometer data threshold based on pipe acceleration
3 expected to be caused by drilling mud pumped at the first mud pump rate through the pipe
4 during the well control operation.

5
6 3. The method of claim 2, wherein the predetermined accelerometer data
7 threshold comprises an acceleration below approximately 20-mg.

8
9 4. The method of claim 1 wherein the act of configuring comprises
10 configuring the telemetry tool to sample accelerometer data at a sampling rate of at least 32-
11 Hz or greater.

12
13 5. The method of claim 1 wherein the act of configuring comprises
14 setting a switching mechanism on the drill pipe to switch on the telemetry tool in response to
15 the predetermined accelerometer data threshold being exceeded.

16
17 6. The method of claim 5, wherein the act of setting the switching
18 mechanism comprises having the switching mechanism supply power from a power source
19 to the telemetry tool when the accelerometer data exceeds the predetermined accelerometer
20 data threshold for a predetermined amount of time.

21
22 7. The method of any one of claims 1 to 6 wherein the first weight is an
23 initial weight for the drilling mud used before the fluid influx.

1 8. The method of any one of claims 1 to 6 wherein the first weight is a
2 calculated weight for the drilling mud calculated after the fluid influx.

3

4 9. The method of any one of claims 1 to 8 wherein the downhole
5 pressure data comprises a bore pressure and an annular pressure measured downhole.

6

7 10. The method of any one of claims 1 to 9 further comprising monitoring
8 the downhole pressure data from the telemetry tool to ensure that an equivalent circulating
9 density of the pumped drilling mud remains substantially at a desired level while pumping
10 the drilling mud.

11

12 11. The method of claim 10, wherein the act of monitoring comprises
13 maintaining a current weight for the drilling mud if the equivalent circulating density of the
14 pumped drilling mud remains substantially at the desired level.

15

16 12. The method of claim 10, wherein the act of monitoring comprises
17 adjusting well control parameters if the equivalent circulating density of the pumped drilling
18 mud does not remain substantially at the desired level.

19

20 13. The method of any one of claims 1 to 12 further comprising:
21 stopping pumping of the drilling mud; and
22 monitoring the well for pressure build up.

23

1 14. The method of claim 13, further comprising resuming normal drilling
2 operations if no substantial pressure build-up is monitored.

3

4 15. The method of claim 13, further comprising repeating the act of
5 shutting-in the well if a pressure build-up is monitored.

6

7 16. A well control method, comprising:

8 measuring accelerometer data with a tool driver on a drill pipe in a well;

9 measuring pressure data with a pressure tool on the drill pipe;

10 transmitting measured pressure data via drilling mud with a telemetry tool on
11 the drill pipe; and

12 controlling the telemetry tool with the tool driver by

13 activating the telemetry tool to transmit the pressure data in response to
14 measured accelerometer data caused by drilling mud being pumped into the drill pipe at
15 least at a normal pump rate used during drilling,

16 deactivating the telemetry tool in response to substantial cessation of
17 accelerometer data caused by stopped pumping of drilling mud due to shutting-in of the well
18 after a fluid influx, and

19 reactivating the telemetry tool to transmit measured pressure data in response
20 to measured accelerometer data at least reaching the predetermined threshold caused by
21 drilling mud being pumped at a first pump rate of a well control operation, the first pump
22 rate being used in the well control operation to kill the fluid influx and being slower than the
23 normal pump rate used during drilling.

1 17. The method of claim 16 wherein the act of reactivating the telemetry
2 tool comprises reactivating the telemetry tool even when a pressure level caused by drilling
3 mud being pumped at the first pump rate is below a level set to activate a pressure sensor of
4 the tool driver.

5

6 18. The method of claim 16 or 17 wherein the act of controlling
7 comprises controlling the supply of power to the telemetry tool with the tool driver.

8

9 19. The method of any one of claims 16 to 18 wherein the predetermined
10 accelerometer data threshold comprises an acceleration below approximately 20-mg.

11

12 20. The method of any one of claims 16 to 19 wherein the act of
13 measuring accelerometer data comprises sampling accelerometer data at a sampling rate of
14 at least 32-Hz or greater.

15

16 21. The method of any one of claims 16 to 20 wherein the act of
17 measuring the accelerometer data comprises measuring with an accelerometer for an
18 acceleration level expected to occur from drilling mud being pumped at the first pump rate
19 through the drill pipe.

20

21 22. The method of any one of claims 16 to 21 wherein the act of
22 transmitting comprises pulsing the measured pressure data to a surface of the well via
23 encoded pressure waves in the drilling mud of the well.

1 23. The method of any one of claims 16 to 22, further comprising using
2 the measured pressure data transmitted by the reactivated telemetry tool to control a choke
3 during the well control operation pumping the drilling mud at the first pump rate.

4

5 24. The method of any one of claims 16 to 23 wherein the act of
6 measuring pressure with a pressure tool comprises measuring bore pressure and annular
7 pressure with the pressure tool on the drill pipe.

8

9 25. A well control system, comprising:

10 a tool driver positioned on a toolstring and having an accelerometer;

11 a power supply operably coupled to the tool driver;

12 a pressure tool operably coupled to the power supply and measuring
13 downhole pressure data; and

14 a telemetry tool operably coupled to the tool driver and the pressure tool, the
15 telemetry tool transmitting measured pressure data via drilling mud and controlled by the
16 tool driver based on measured accelerometer data,

17 wherein in response to measured accelerometer data caused by drilling mud
18 being pumped into the drill pipe at least at a normal pump rate used during drilling, the tool
19 driver activates the telemetry tool to transmit pressure data measured by the pressure tool,

20 wherein in response to substantial cessation of measured accelerometer data
21 caused by stopped pumping of drilling mud due to shutting-in of the well after a fluid influx,
22 the tool driver deactivates the telemetry tool, and

1 wherein in response to measured accelerometer data at least reaching the
2 predetermined threshold caused by drilling mud being pumped at a first pump rate of a well
3 control operation the tool driver reactivates the telemetry tool to transmit pressure data
4 measured by the pressure tool, the first pump rate being used in the well control operation to
5 kill the fluid influx and being slower than the normal pump rate used during drilling.

6

7 26. The well control system of claim 25 wherein to control the telemetry
8 tool, the tool driver maintains the telemetry tool activated to transmit measured pressure data
9 in response to measured accelerometer data caused by drilling mud being pumped into the
10 drill pipe at the normal pump rate.

11

12 27. The well control system of claim 25 wherein to control the telemetry
13 tool, the tool driver deactivates the telemetry tool in response to substantial cessation of
14 measured accelerometer data caused by stopped pumping of drilling mud.

15

16 28. The well control system of claim 25 wherein to control the telemetry
17 tool, the tool driver comprise a switching mechanism to control the supply of power from
18 the power supply to the telemetry tool based on the measured accelerometer data.

19

20 29. The well control system of any one of claims 25 to 28 wherein the
21 predetermined accelerometer data threshold comprises an acceleration below approximately
22 20-mg.

23

1 30. The well control system of any one of claims 25 to 29 wherein the
2 tool driver samples the accelerometer for data at a sampling rate of at least 32-Hz or greater.

3

4 31. The well control system of any one of claims 25 to 30 wherein to
5 transmit measured pressure data, the telemetry tool sends the measured pressure data to a
6 surface of the well via encoded pressure waves in the drilling mud of the well.

7

8 32. The well control system of any one of claims 25 to 31, further
9 comprising an analysis tool obtaining the measured pressure data transmitted by the
10 telemetry tool and providing analyzed data to control a choke during the well control
11 operation pumping the drilling mud at the first pump rate.

12

13 33. The well control system of any one of claims 25 to 32 wherein the
14 pressure data comprises bore pressure and annular pressure.

15

16 34. A well control method, comprising:
17 configuring a telemetry tool on a drill pipe in a well to activate in response to
18 a predetermined threshold associated with accelerometer data;
19 shutting-in the well in response to a fluid influx during drilling;
20 obtaining drill pipe and casing pressures of the shut-in well;
21 pumping drilling mud having a first weight into the drill pipe at a first mud
22 pump rate, the first mud pump rate being used in a well control operation to kill the fluid
23 influx and being slower than a normal mud pump rate used during drilling, wherein the first

1 weight is a calculated weight for the drilling mud calculated after the fluid influx;
2 obtaining downhole pressure data from the telemetry tool activated in
3 response to the predetermined accelerometer data threshold;
4 comparing a static equivalent mud weight obtained from the pressure data to
5 the drill pipe and casing pressures; and
6 changing the first weight for the drilling mud to a second weight when
7 indicated by the comparison.
8

9 35. The method of claim 34 wherein the act of configuring comprises
10 selecting the predetermined accelerometer data threshold based on pipe acceleration
11 expected to be caused by drilling mud pumped at the first pump rate through the pipe during
12 the well control operation.
13

14 36. The method of claim 34 wherein the act of configuring comprises
15 configuring the telemetry tool to sample accelerometer data at a sampling rate of at least 32-
16 Hz or greater.
17

18 37. The method of claim 34 wherein the act of configuring comprises
19 setting a switching mechanism on the drill pipe to switch on the telemetry tool in response to
20 the predetermined accelerometer data threshold being exceeded.
21

22 38. The method of any one of claims 34 to 37 wherein the first weight is
23 an initial weight for the drilling mud used before the fluid influx.

1 39. The method of any one of claims 34 to 38 wherein the downhole
2 pressure data comprises a bore pressure and an annular pressure measured downhole.

3

4 40. The method of any one of claims 34 to 39, further comprising
5 monitoring the downhole pressure data from the telemetry tool to ensure that an equivalent
6 circulating density of the pumped drilling mud remains substantially at a desired level while
7 pumping the drilling mud.

8

9 41. The method of any one of claims 34 to 40 further comprising:
10 stopping pumping of the drilling mud; and
11 monitoring the well for pressure build up.

12

13 42. A well control method, comprising:
14 configuring a telemetry tool on a drill pipe in a well to activate in response to
15 a predetermined threshold associated with accelerometer data;
16 shutting-in the well in response to a fluid influx during drilling;
17 obtaining drill pipe and casing pressures of the shut-in well;
18 pumping drilling mud having a first weight into the drill pipe at a first mud
19 pump rate, the first mud pump rate being used in a well control operation to kill the fluid
20 influx and being slower than a normal mud pump rate used during drilling;
21 obtaining downhole pressure data from the telemetry tool activated in
22 response to the predetermined accelerometer data threshold;
23 comparing a static equivalent mud weight obtained from the pressure data to

1 the drill pipe and casing pressures;

2 changing the first weight for the drilling mud to a second weight if necessary

3 based on the comparison;

4 stopping pumping of the drilling mud; and

5 monitoring the well for pressure build up.

6

7 43. The method of claim 42, wherein the act of configuring comprises

8 selecting the predetermined accelerometer data threshold based on pipe acceleration

9 expected to be caused by drilling mud pumped at the first mud pump rate through the pipe

10 during the well control operation.

11

12 44. The method of claim 42, wherein the act of configuring comprises

13 configuring the telemetry tool to sample accelerometer data at a sampling rate of at least 32-

14 Hz or greater.

15

16 45. The method of claim 42 wherein the act of configuring comprises

17 setting a switching mechanism on the drill pipe to switch on the telemetry tool in response to

18 the predetermined accelerometer data threshold being exceeded.

19

20 46. The method of any one of claims 42 to 45 wherein the first weight is

21 an initial weight for the drilling mud used before the fluid influx.

22

23

1 47. The method of any one of claims 42 to 45 wherein the first weight is a
2 calculated weight for the drilling mud calculated after the fluid influx.

3

4 48. The method of any one of claims 42 to 47 wherein the downhole
5 pressure data comprises a bore pressure and an annular pressure measured downhole.

6

7 49. The method of any one of claims 42 to 48 further comprising
8 monitoring the downhole pressure data from the telemetry tool to ensure that an equivalent
9 circulating density of the pumped drilling mud remains substantially at a desired level while
10 pumping the drilling mud.

11

12 50. A well control method, comprising:
13 measuring accelerometer data with a tool driver on a drill pipe in a well;
14 measuring pressure data with a pressure tool on the drill pipe;
15 transmitting measured pressure data via drilling mud with a telemetry tool on
16 the drill pipe;
17 controlling the telemetry tool with the tool driver by
18 activating the telemetry tool to transmit the pressure data in response to
19 measured accelerometer data caused by drilling mud being pumped into the drill pipe at
20 least at a normal pump rate,
21 deactivating the telemetry tool in response to substantial cessation of
22 accelerometer data caused by stopped pumping of drilling mud, and
23 reactivating the telemetry tool to transmit measured pressure data in response

1 to measured accelerometer data exceeding a predetermined threshold caused by drilling mud
2 being pumped at a first pump rate of a well control operation, the first pump rate being used
3 in a well control operation to kill a fluid influx and being slower than the normal pump used
4 during drilling; and

5 using the measured pressure data transmitted by the reactivated telemetry tool
6 to control a choke during the well control operation pumping the drilling mud at the first
7 pump rate.

8

9 51. The method of claim 50 wherein the act of reactivating the telemetry
10 tool comprises reactivating the telemetry tool even when a pressure level caused by drilling
11 mud being pumped at the first pump rate is below a level set to activate a pressure sensor of
12 the tool driver.

13

14 52. The method of claim 50 or 51 wherein the act of controlling
15 comprises controlling the supply of power to the telemetry tool with the tool driver.

16

17 53. The method of any one of claims 50 to 52 wherein the predetermined
18 accelerometer data threshold comprises an acceleration below approximately 20-mg.

19

20 54. The method of any one of claims 50 to 53 wherein the act of
21 measuring accelerometer data comprises sampling accelerometer data at a sampling rate of
22 at least 32-Hz or greater.

23

1 55. The method of any one of claims 50 to 54 wherein the act of
2 measuring the accelerometer data comprises measuring with an accelerometer for an
3 acceleration level expected to occur from drilling mud being pumped at the first pump rate
4 through the drill pipe.

5

6 56. The method of any one of claims 50 to 55, wherein the act of
7 transmitting comprises pulsing the measured pressure data to a surface of the well via
8 encoded pressure waves in the drilling mud of the well.

9

10 57. The method of any one of claims 50 to 56 wherein the act of
11 measuring pressure with a pressure tool comprises measuring bore pressure and annular
12 pressure with the pressure tool on the drill pipe.

13

14 58. A well control system, comprising:

15 a tool driver positioned on a toolstring and having an accelerometer;

16 a power supply operably coupled to the tool driver;

17 a pressure tool operably coupled to the power supply and measuring
18 downhole pressure data;

19 a telemetry tool operably coupled to the tool driver and the pressure tool, the
20 telemetry tool transmitting measured pressure data via drilling mud and controlled by the
21 tool driver based on measured accelerometer data, wherein in response to measured
22 accelerometer data exceeding a predetermined threshold caused by drilling mud being
23 pumped at a first pump rate of a well control operation through the tool string, the tool

1 driver activates the telemetry tool to transmit pressure data measured by the pressure tool,
2 the first pump rate being used in the well control operation to kill a fluid influx and being
3 slower than a normal pump used during drilling; and

4 an analysis tool obtaining the measured pressure data transmitted by the
5 telemetry tool and providing analyzed data to control a choke during the well control
6 operation pumping the drilling mud at the first pump rate.

7

8 59. The well control system of claim 58 wherein to control the telemetry
9 tool, the tool driver maintains the telemetry tool activated to transmit measured pressure data
10 in response to measured accelerometer data caused by drilling mud being pumped into the
11 drill pipe at the normal pump rate.

12

13 60. The well control system of claim 58 wherein to control the telemetry
14 tool, the tool driver deactivates the telemetry tool in response to substantial cessation of
15 measured accelerometer data caused by stopped pumping of drilling mud.

16

17 61. The well control system of claim 58 wherein to control the telemetry
18 tool, the tool driver comprise a switching mechanism to control the supply of power from
19 the power supply to the telemetry tool based on the measured accelerometer data.

20

21 62. The well control system of any one of claims 58 to 61 wherein the
22 predetermined accelerometer data threshold comprises an acceleration below approximately
23 20-mg.

1 63. The well control system of nay one of claims 58 to 62, wherein the
2 tool driver samples the accelerometer for data at a sampling rate of at least 32-Hz or greater.

3

4 64. The well control system of any one of claims 58 to 63, wherein to
5 transmit measured pressure data, the telemetry tool sends the measured pressure data to a
6 surface of the well via encoded pressure waves in the drilling mud of the well.

7

8 65. The well control system of any one of claims 58 to 64 wherein the
9 pressure data comprises bore pressure and annular pressure.

TITLE: SYSTEM AND METHOD FOR OBTAINING AND USING DOWNHOLE DATA DURING WELL CONTROL OPERATIONS

FIRST NAMED INVENTOR: BARRY SCHNEIDER

ATTY. DKT. NO.: 135-0050US

1/6

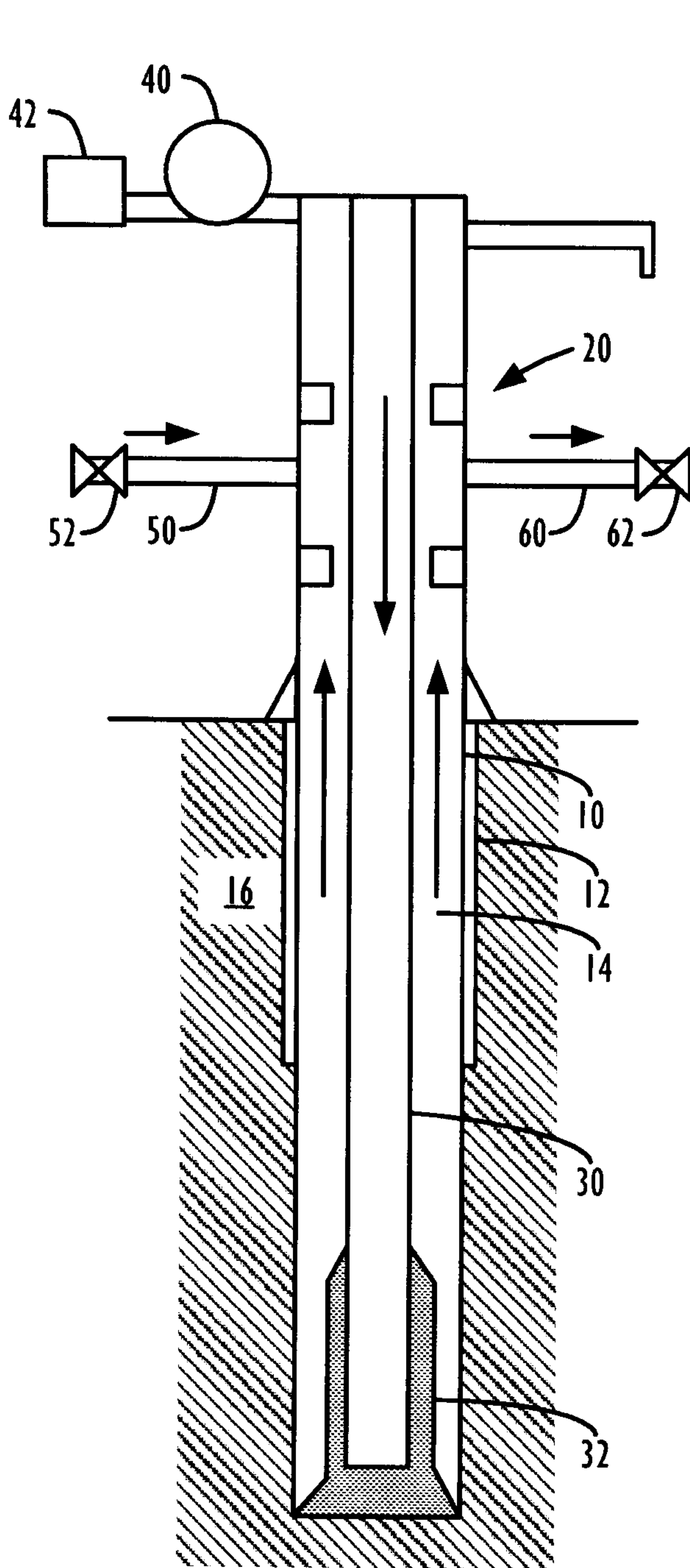


FIG. 1A
(Prior Art)

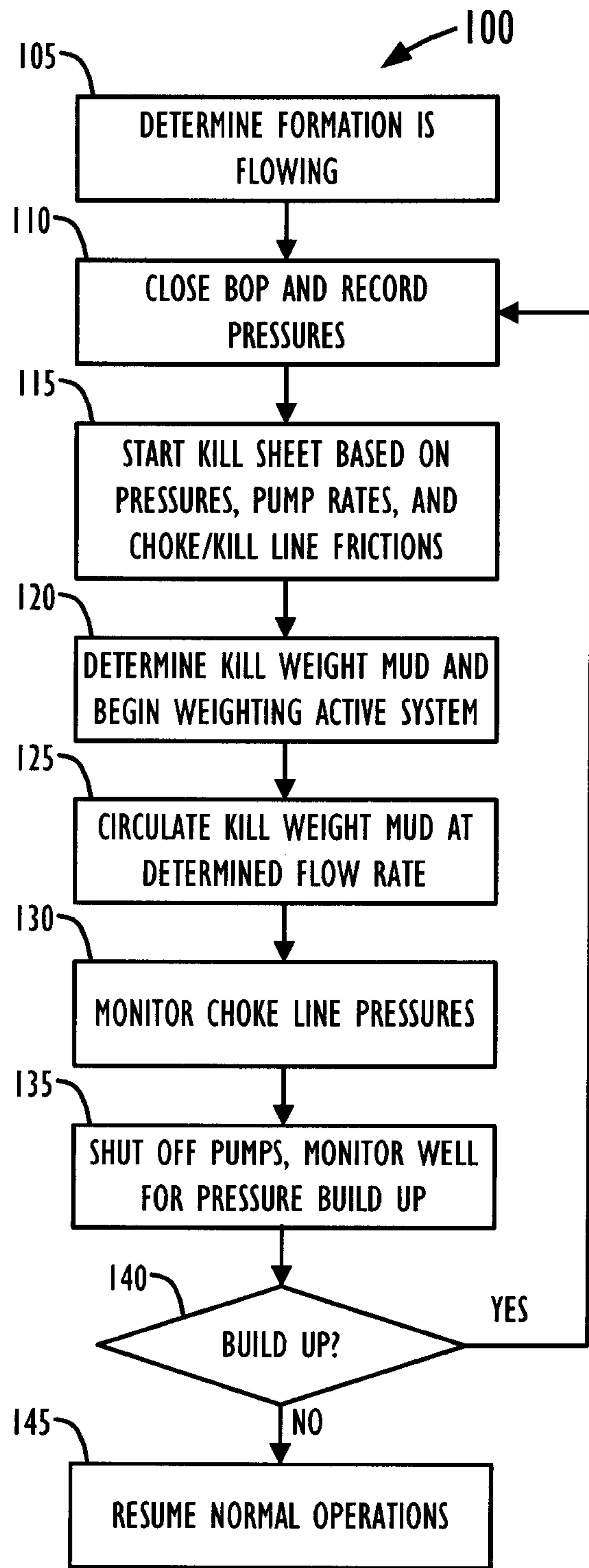


FIG. 1B
(Prior Art)

TITLE: SYSTEM AND METHOD FOR OBTAINING AND USING DOWNHOLE DATA DURING WELL CONTROL OPERATIONS

FIRST NAMED INVENTOR: BARRY SCHNEIDER

ATTY. DKT. NO.: 135-0050US

2/6

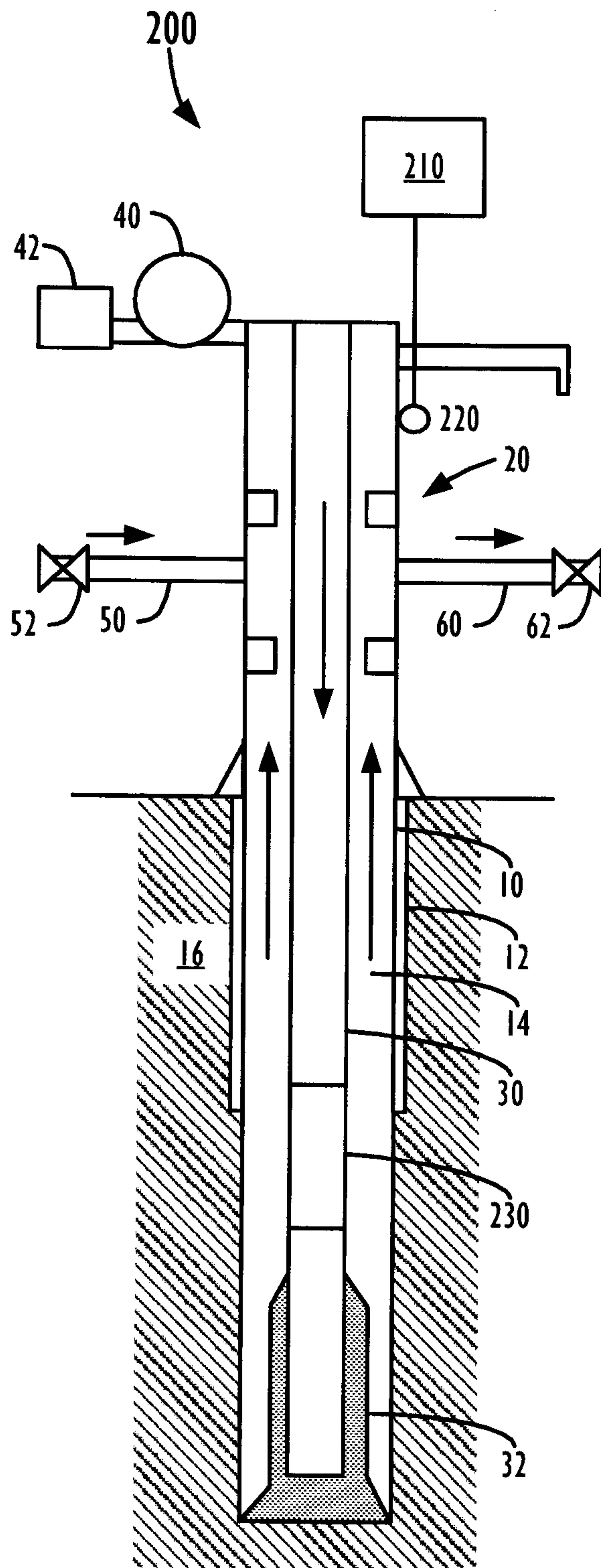


FIG. 2A

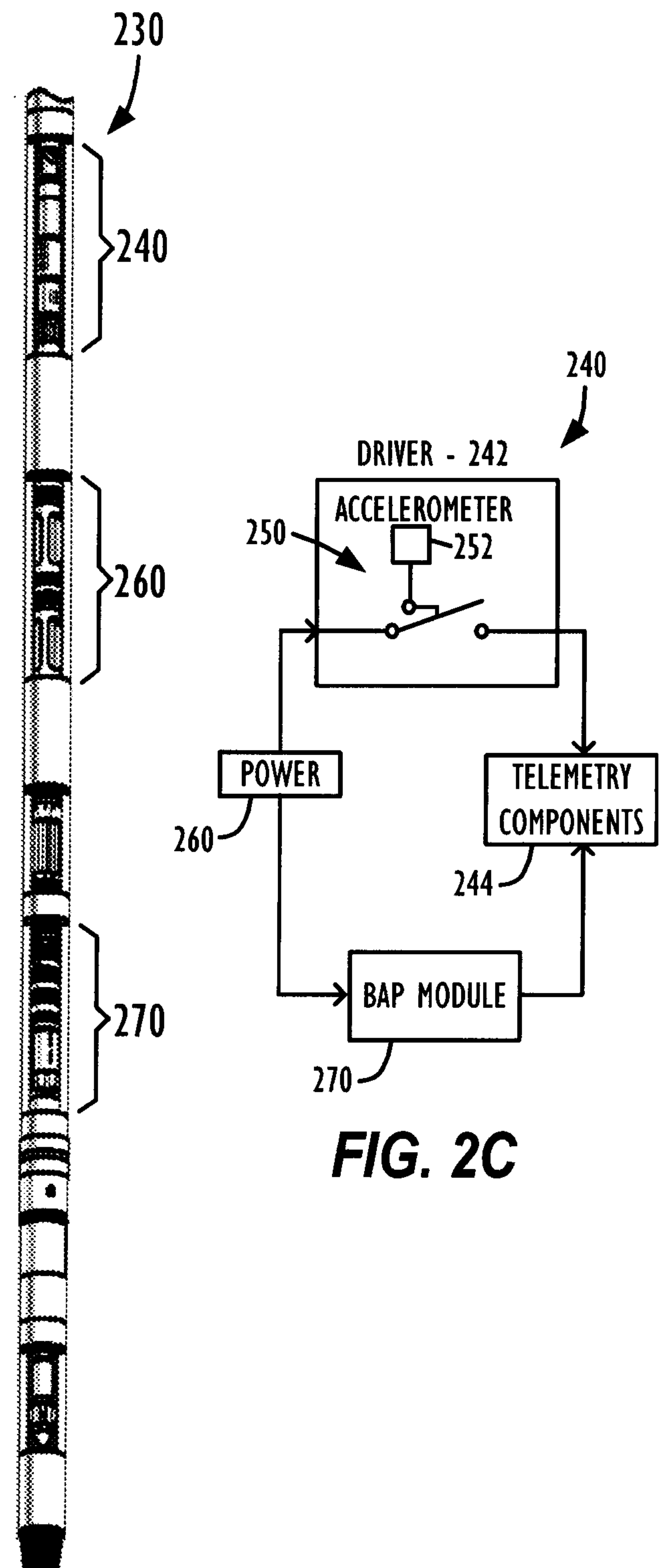


FIG. 2B

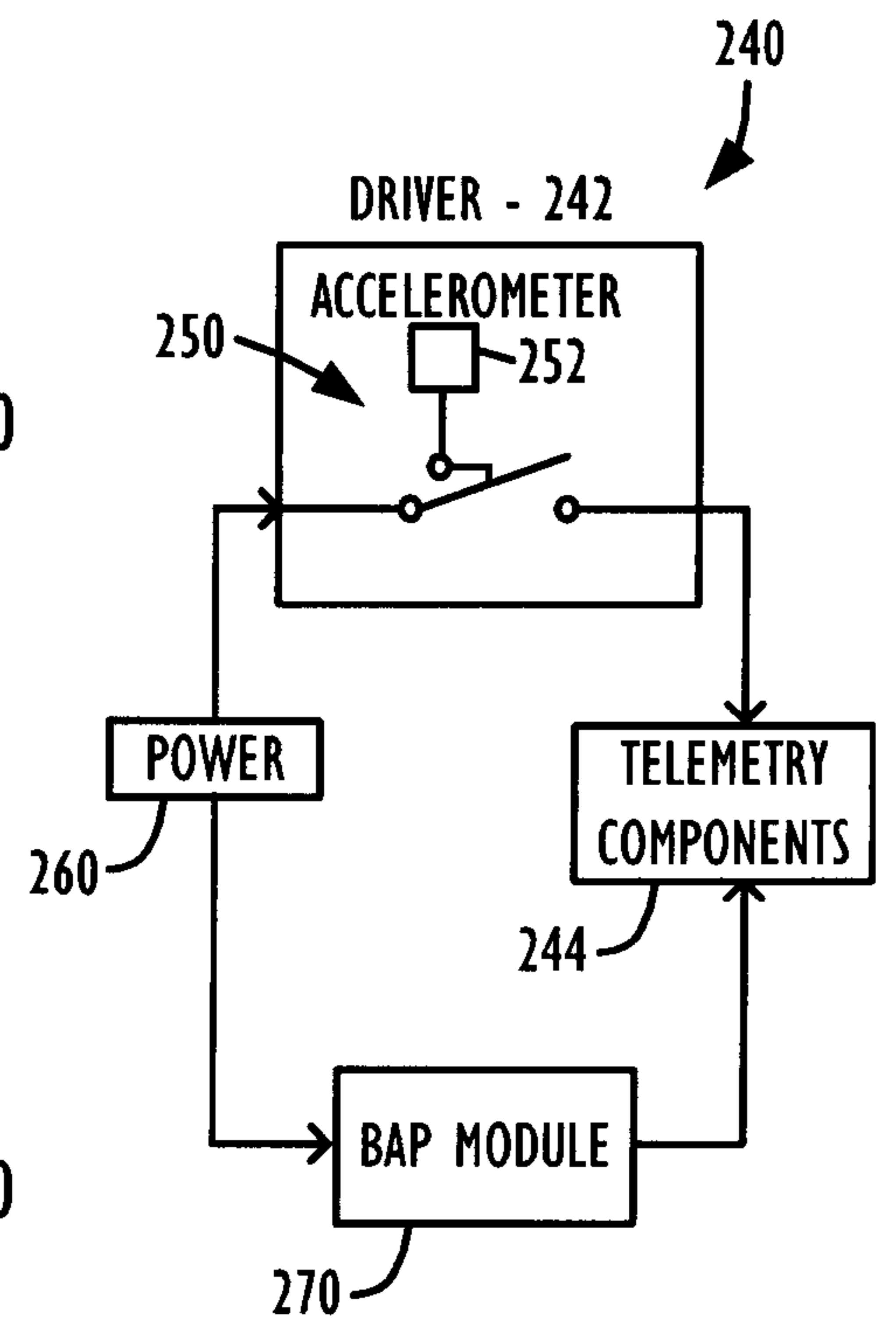
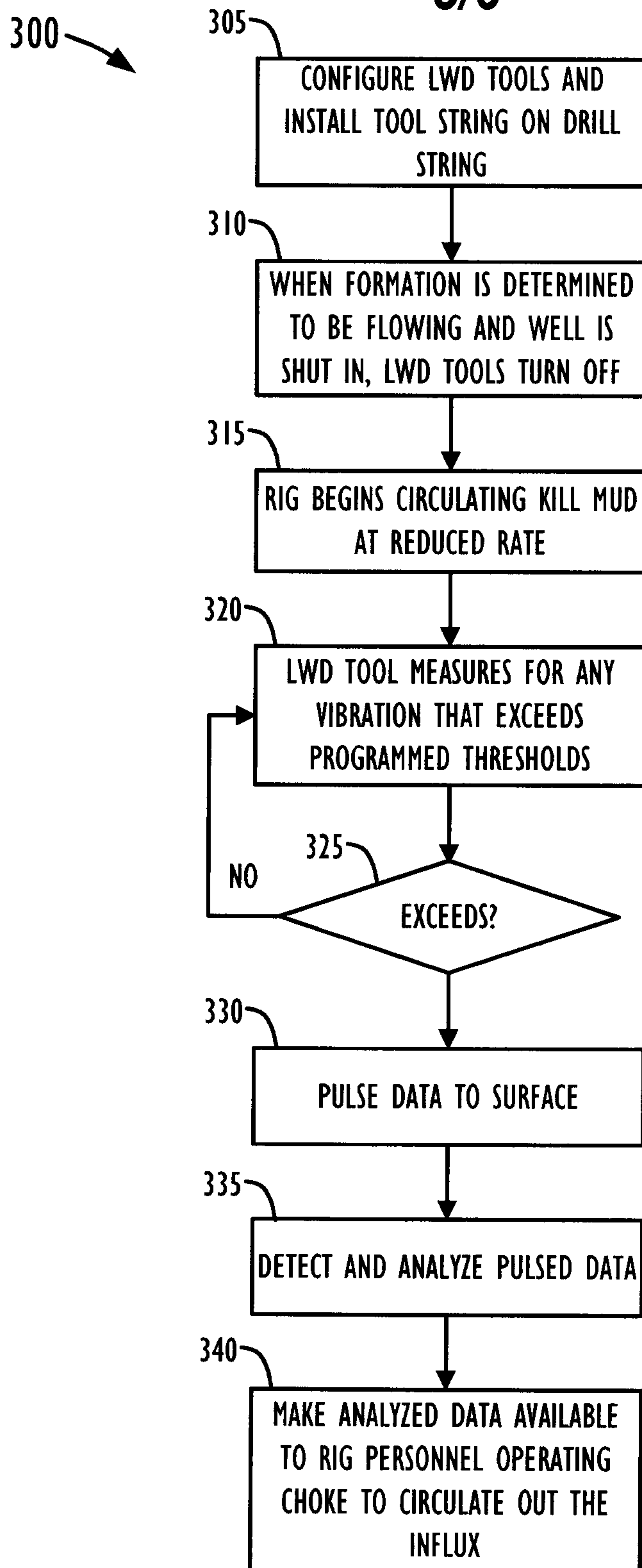


FIG. 2C

TITLE: SYSTEM AND METHOD FOR OBTAINING AND USING DOWNHOLE DATA DURING WELL CONTROL OPERATIONS

FIRST NAMED INVENTOR: BARRY SCHNEIDER

ATTY. DKT. NO.: 135-0050US

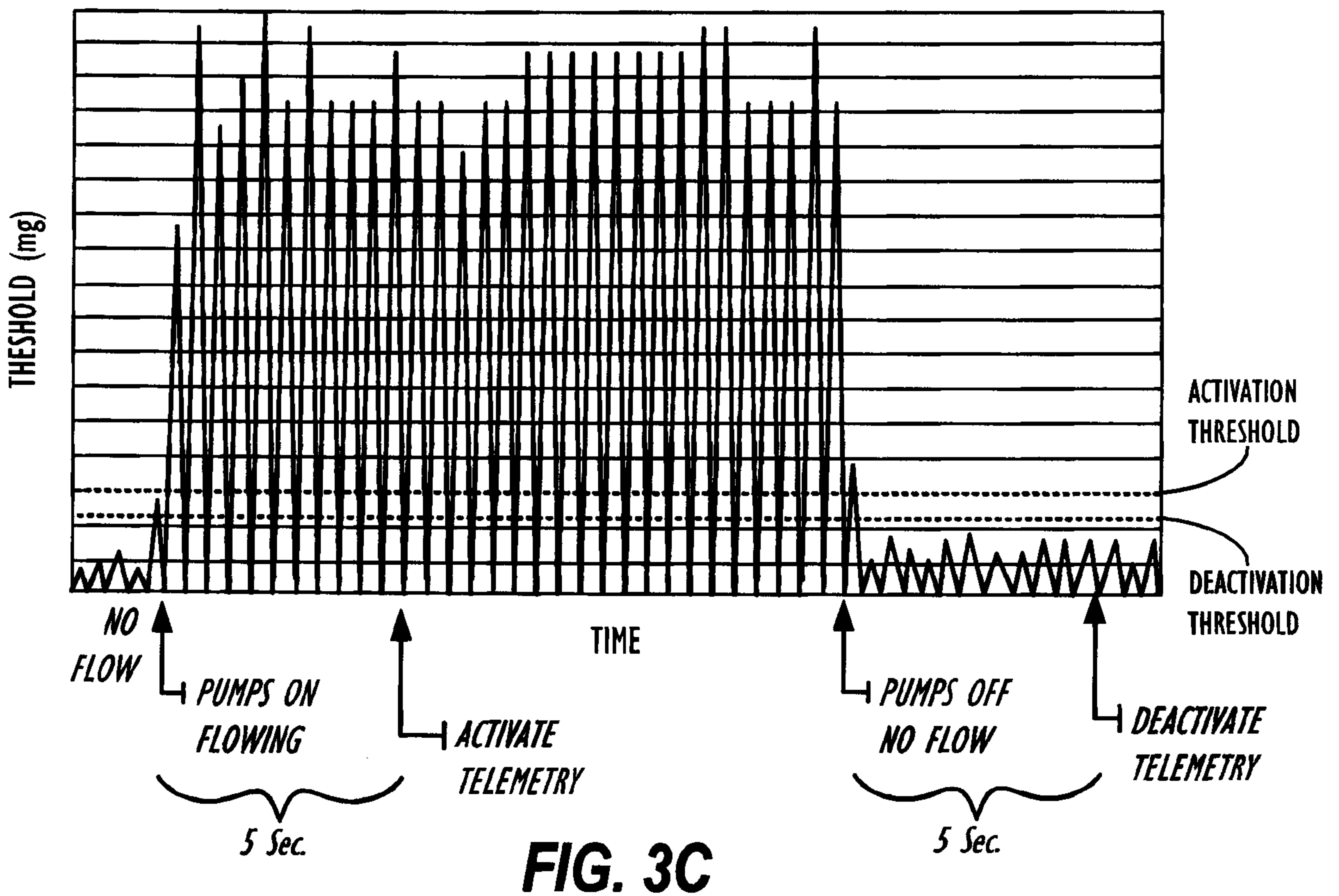
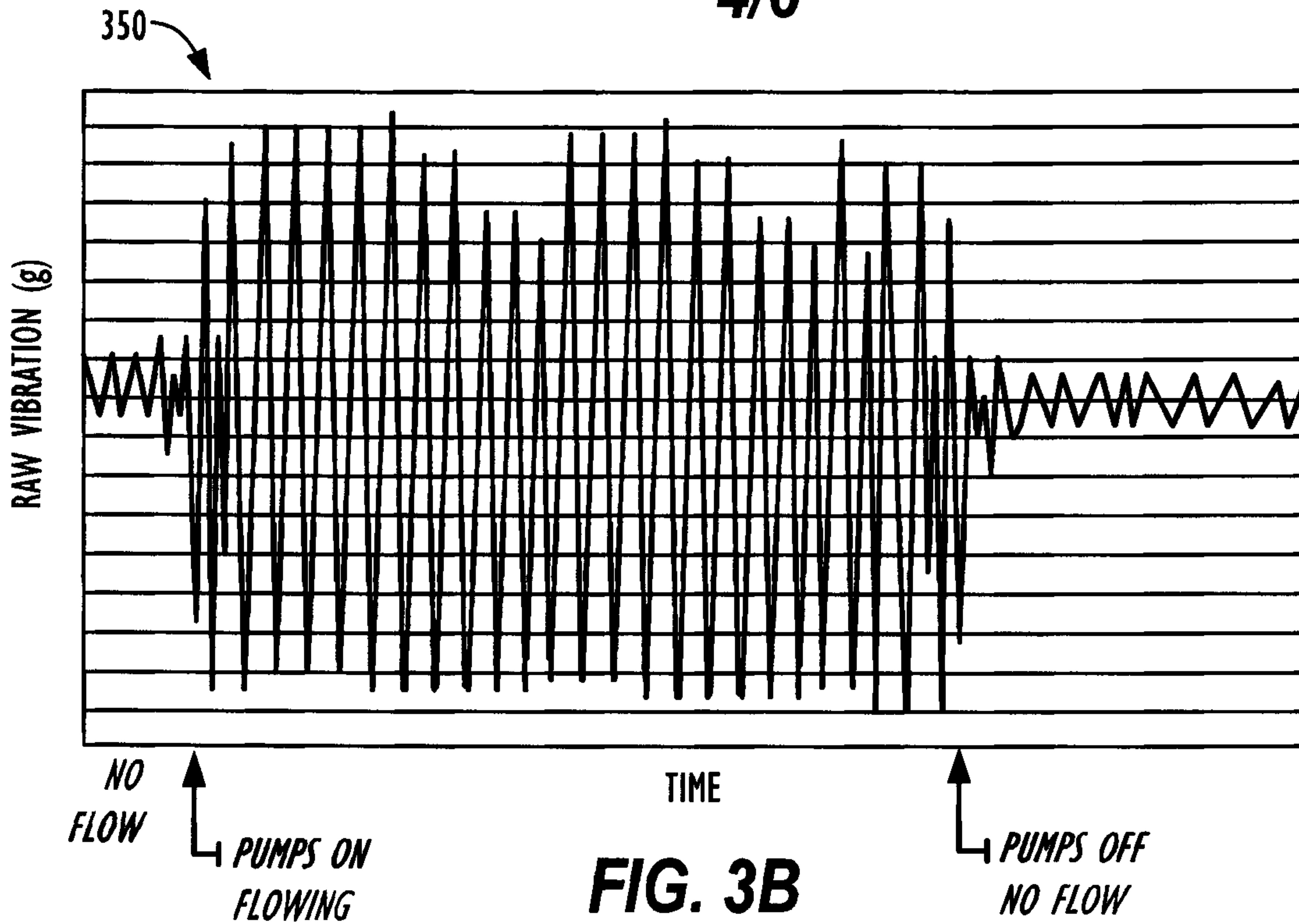
3/6**FIG. 3A**

TITLE: SYSTEM AND METHOD FOR OBTAINING AND USING DOWNHOLE DATA DURING WELL CONTROL OPERATIONS

FIRST NAMED INVENTOR: BARRY SCHNEIDER

ATTY. DKT. NO.: 135-0050US

4/6



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5/6

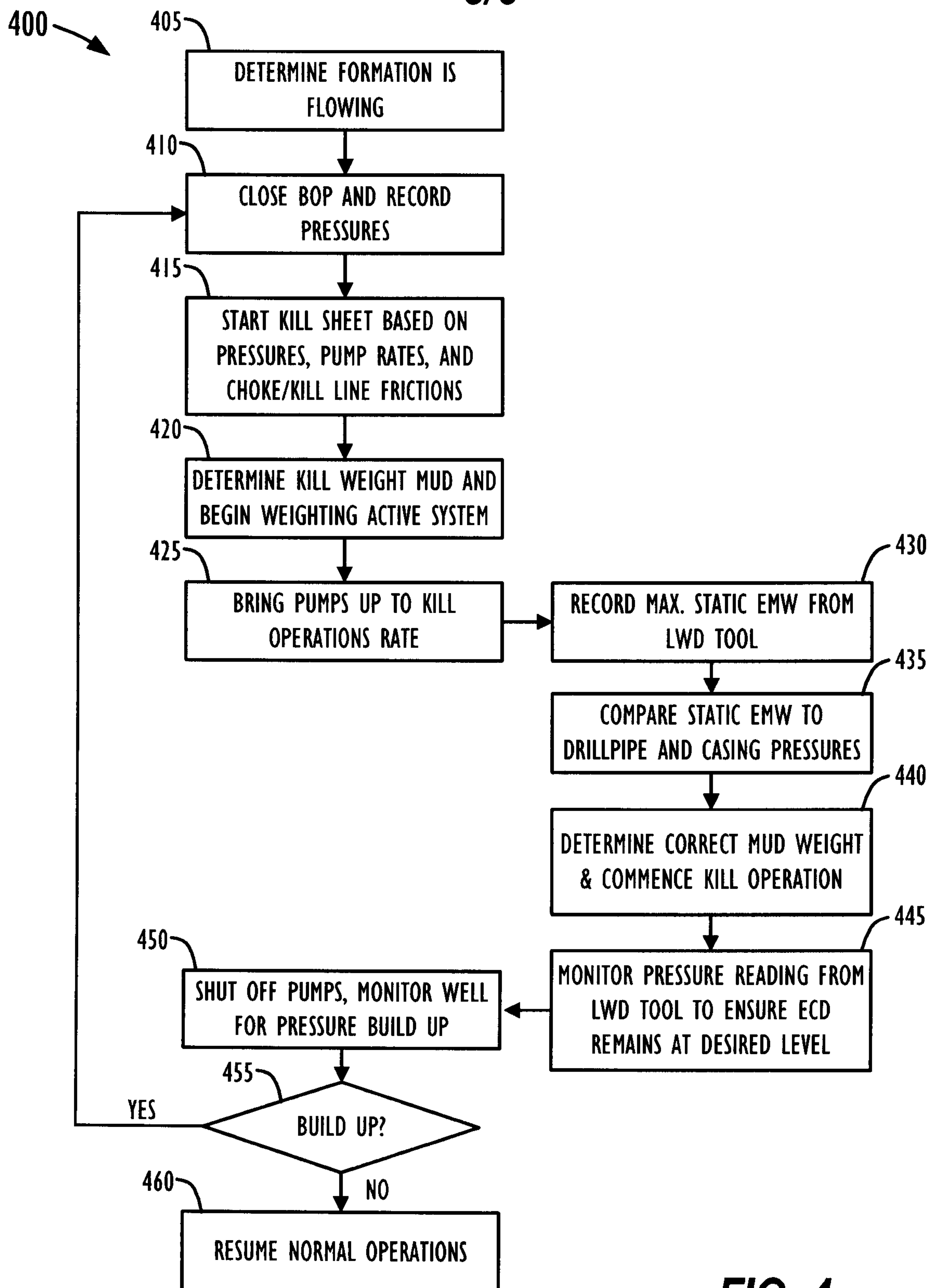


FIG. 4

TITLE: SYSTEM AND METHOD FOR OBTAINING AND USING DOWNHOLE DATA DURING WELL CONTROL OPERATIONS

FIRST NAMED INVENTOR: BARRY SCHNEIDER

ATTY. DKT. NO.: 135-0050US

6/6

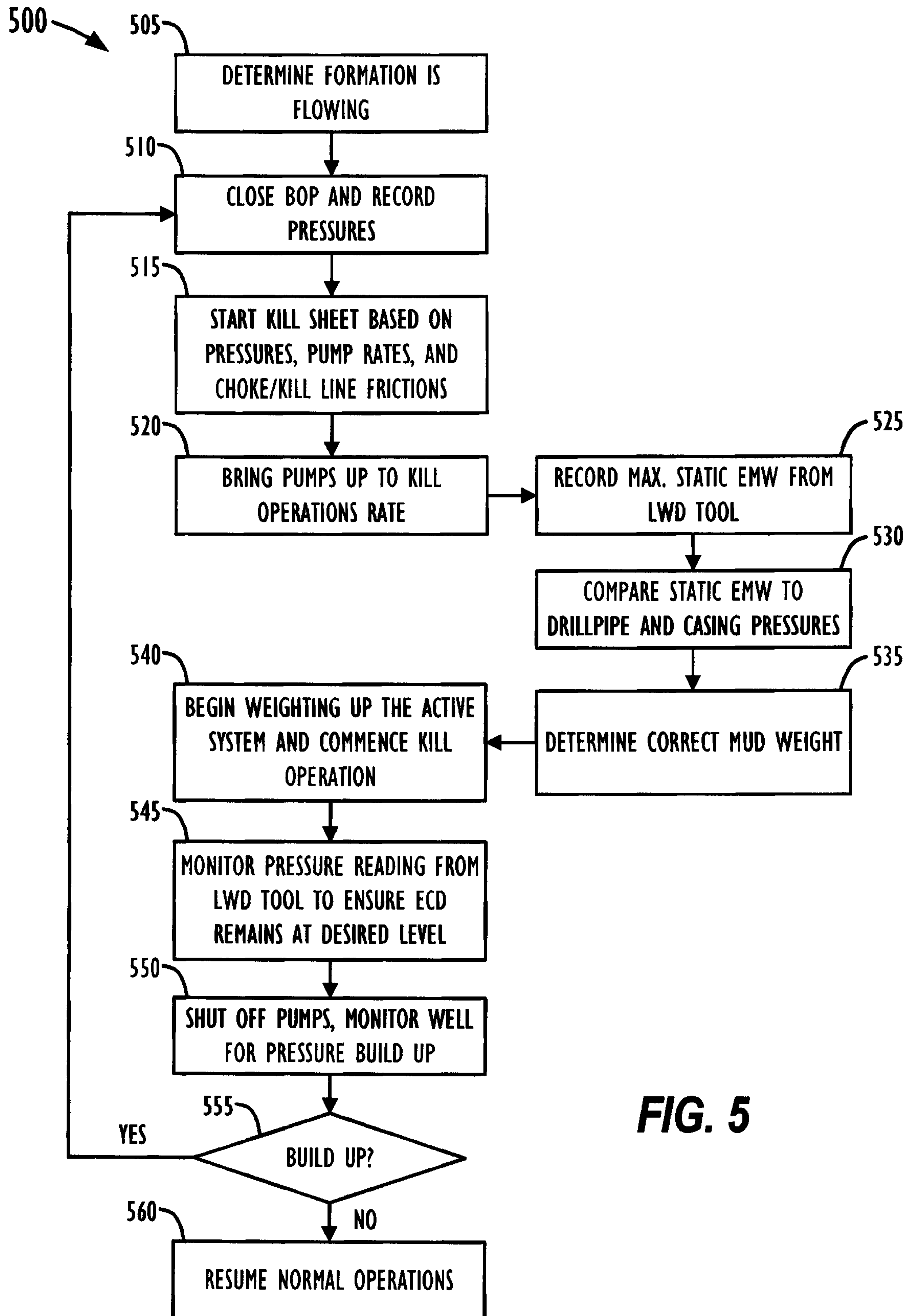


FIG. 5

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