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(54) **AUTODRILLER SYSTEM**

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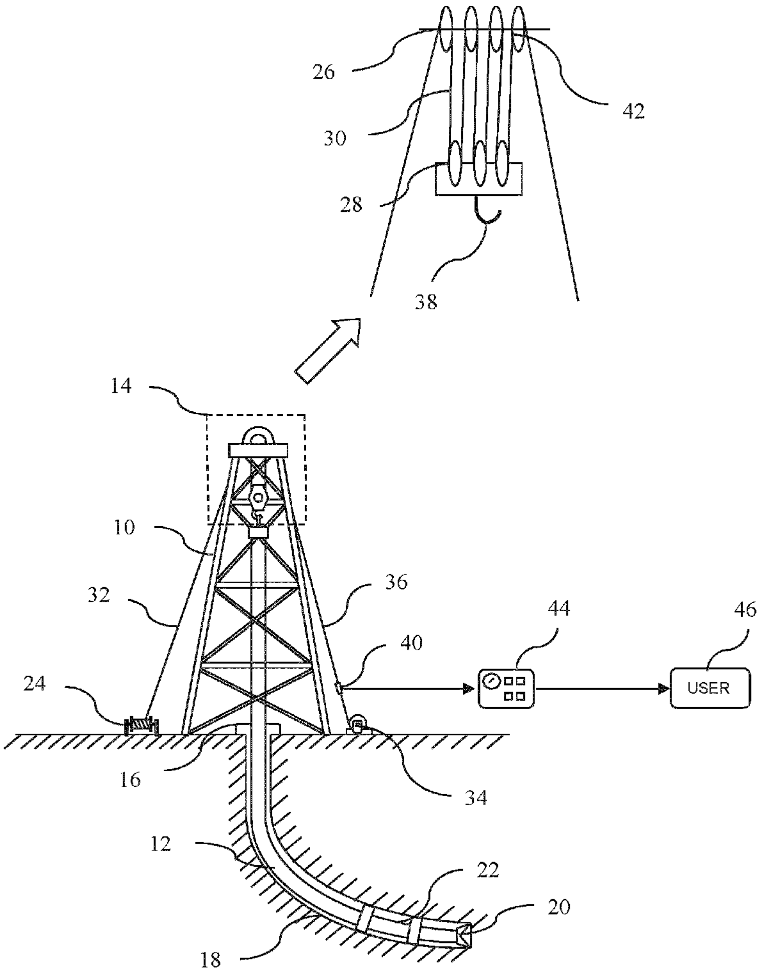
USPC **175/27**; 175/24

(57) **ABSTRACT**

An autodriller provides an automatic self calibration system to predict both axial and rotational friction coefficients from the surface measurements such as hookload and surface torque while a drill bit is off bottom. The friction coefficients are used to calculate the friction forces between drillstring and the wellbore while the bit is on bottom during drilling operation to estimate downhole weight on the bit and bit torque, and use the estimates to alter the drilling process.



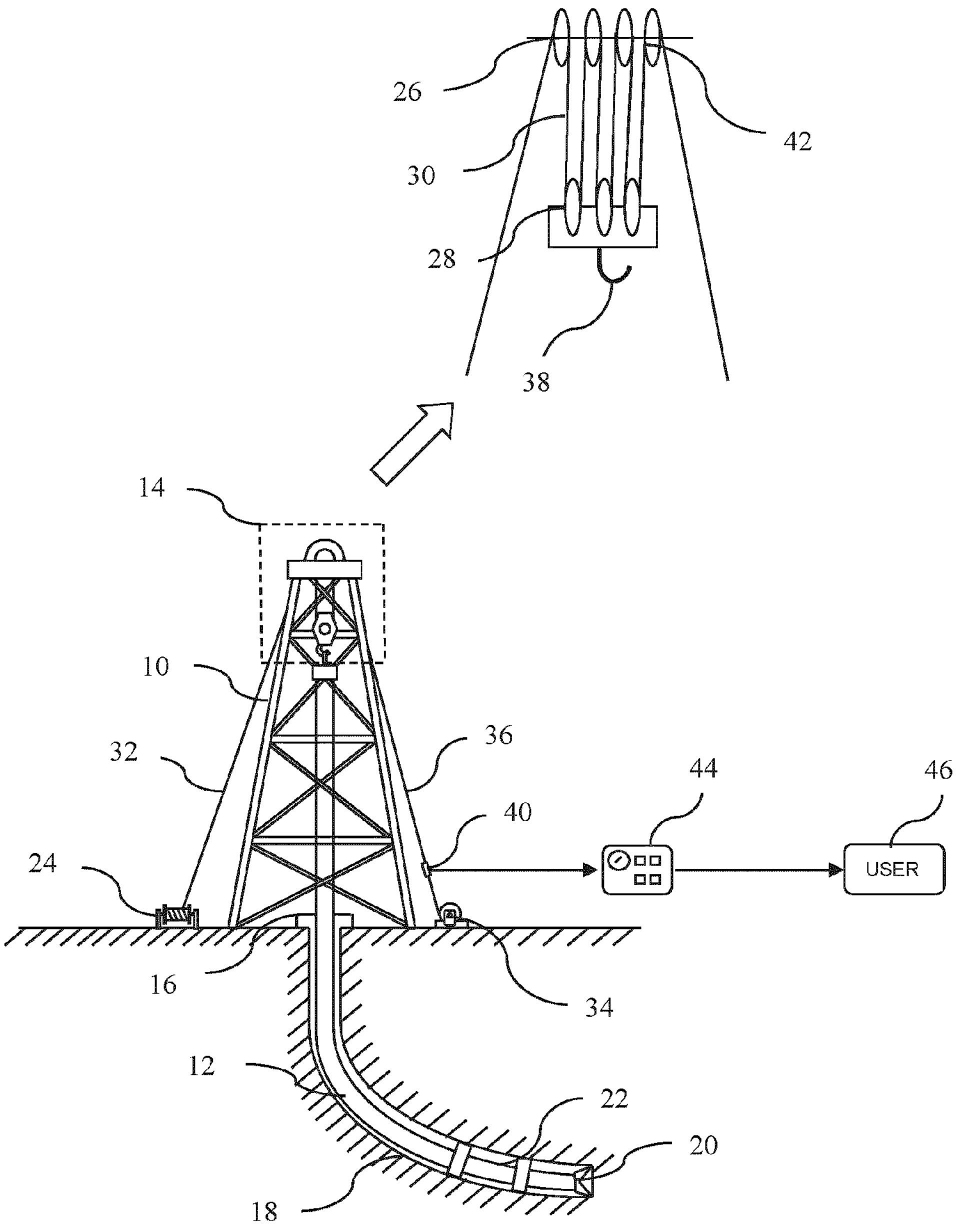


Fig. 1

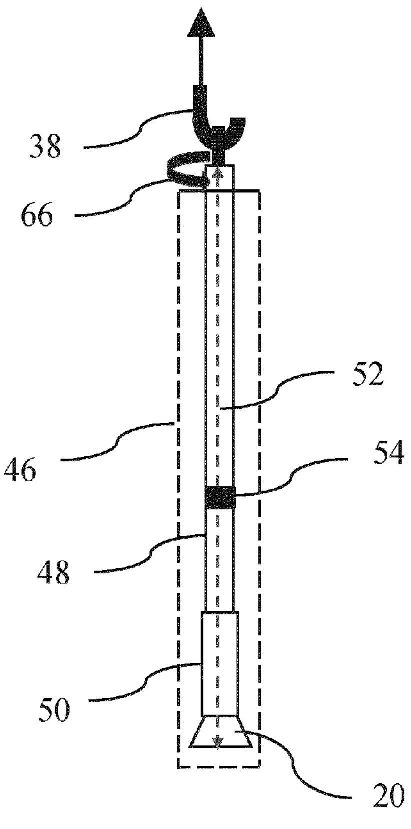


Fig. 2a

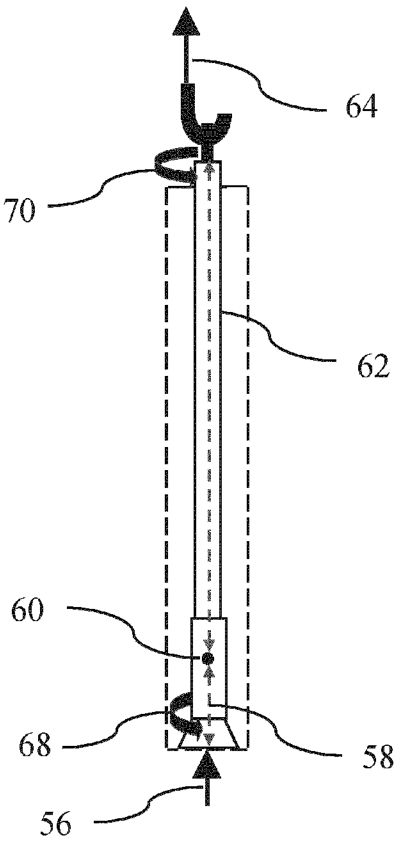


Fig. 2b

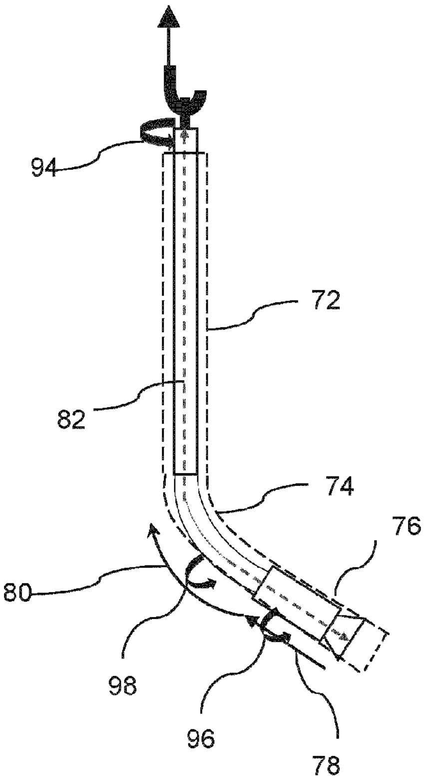


Fig. 3a

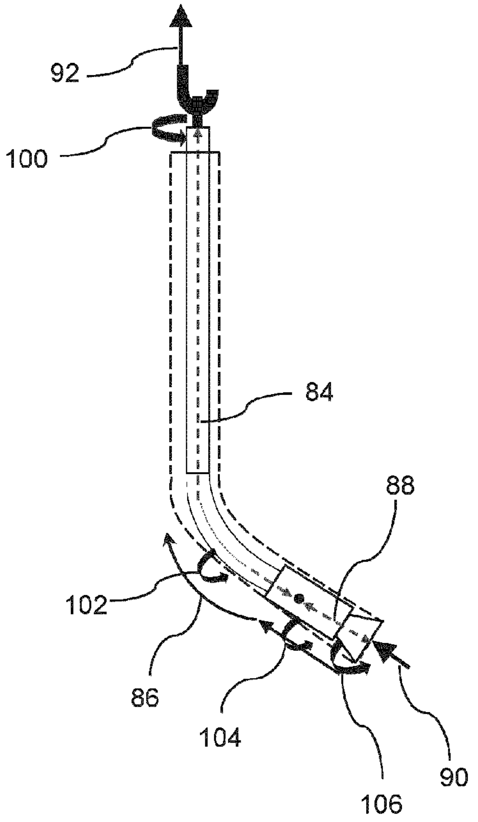


Fig. 3b

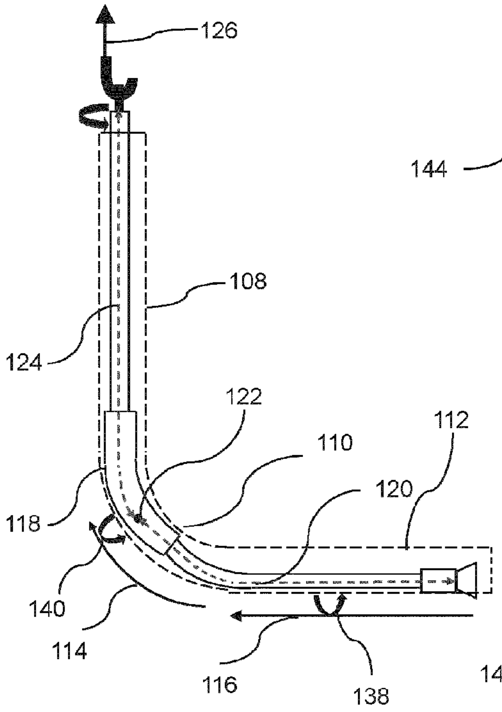

126
108
124
122
110
112
120
118
140
114
116
138

Fig. 4a

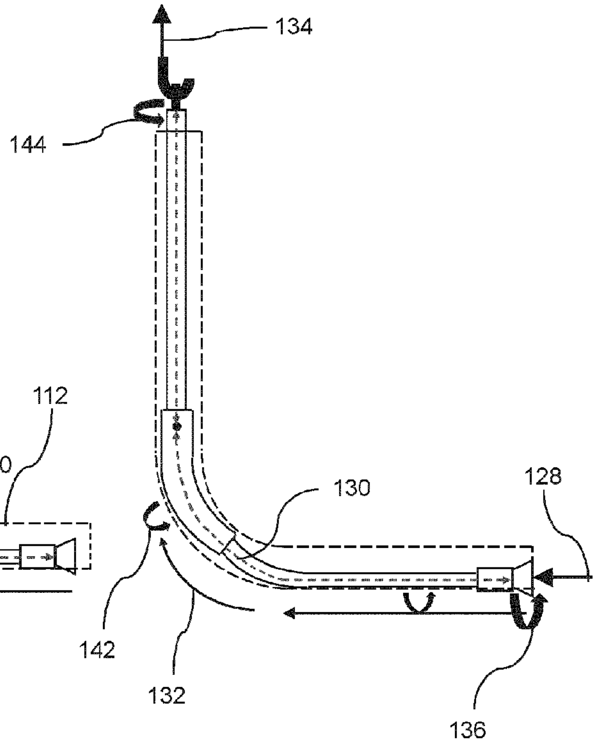

134
144
130
128
142
132
136

Fig. 4b

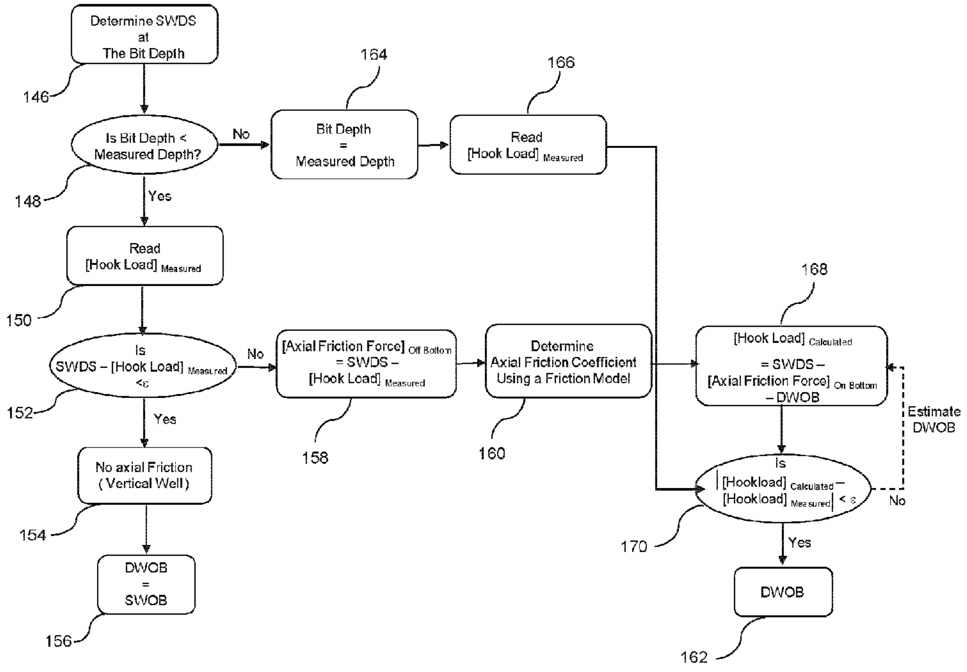

Determine SWDS at The Bit Depth
146
Is Bit Depth < Measured Depth?
148
No
Yes
Bit Depth = Measured Depth
164
Read [Hook Load] Measured
166
Read [Hook Load] Measured
150
Is SWDS – [Hook Load] Measured <ε
152
No
Yes
[Axial Friction Force] Off Bottom = SWDS – [Hook Load] Measured
158
Determine Axial Friction Coefficient Using a Friction Model
160
[Hook Load] Calculated = SWDS – [Axial Friction Force] On Bottom – DWOB
168
Estimate DWOB
Is |[Hookload] Calculated – [Hookload] Measured| < ε
170
No
Yes
DWOB
162
No axial Friction (Vertical Well)
154
DWOB = SWOB
156

Fig. 5

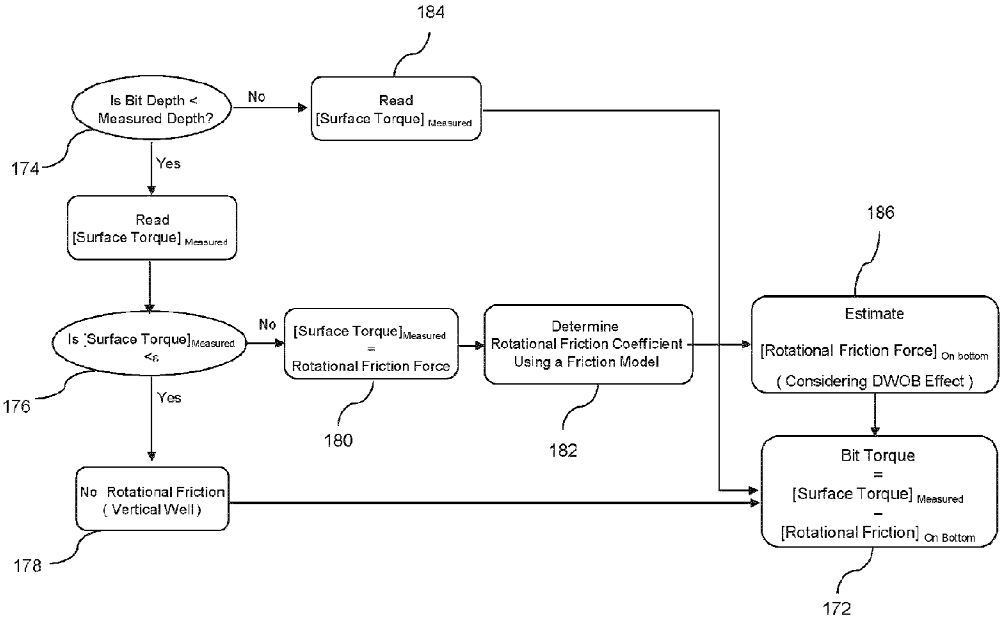

184
Is Bit Depth < Measured Depth?
No
Read [Surface Torque] Measured
174
Yes
Read [Surface Torque] Measured
186
Is [Surface Torque]Measured <ε
No
[Surface Torque]Measured = Rotational Friction Force
Determine Rotational Friction Coefficient Using a Friction Model
Estimate [Rotational Friction Force] On bottom (Considering DWOB Effect)
176
Yes
180
182
No Rotational Friction (Vertical Well)
Bit Torque = [Surface Torque] Measured − [Rotational Friction] On Bottom
178
172

Fig. 6

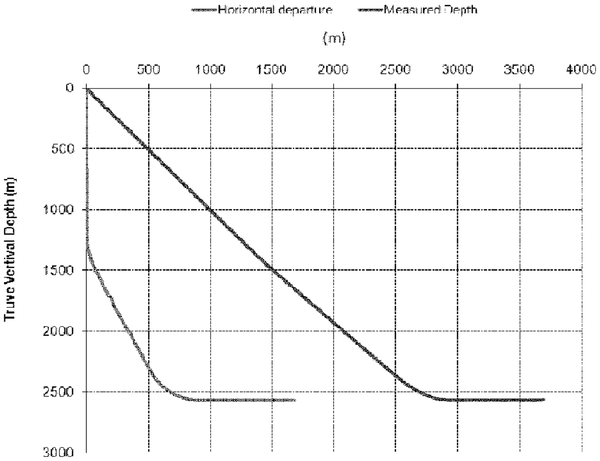

Horizontal departure
Measured Depth
(m)
0
500
1000
1500
2000
2500
3000
3500
4000
Truve Vertival Depth (m)
0
500
1000
1500
2000
2500
3000

Fig. 7

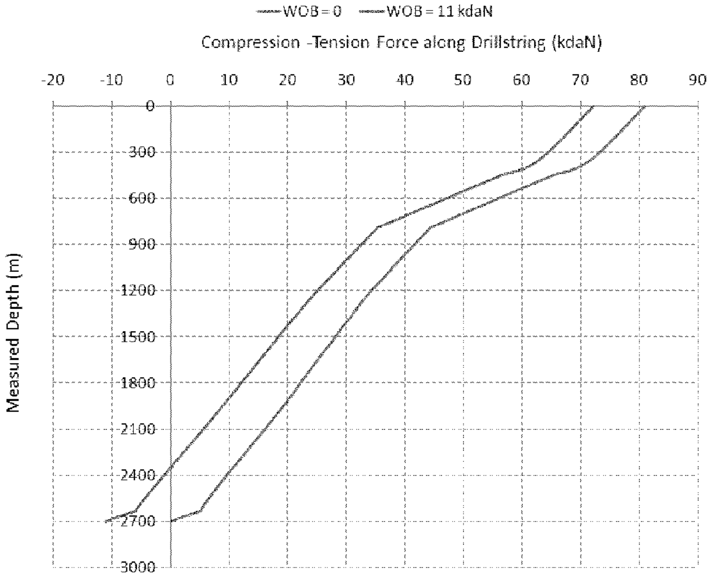

WOB = 0
WOB = 11 kdaN
Compression -Tension Force along Drillstring (kdaN)
-20
-10
0
10
20
30
40
50
60
70
80
90
Measured Depth (m)
0
300
600
900
1200
1500
1800
2100
2400
2700
3000

Fig. 8

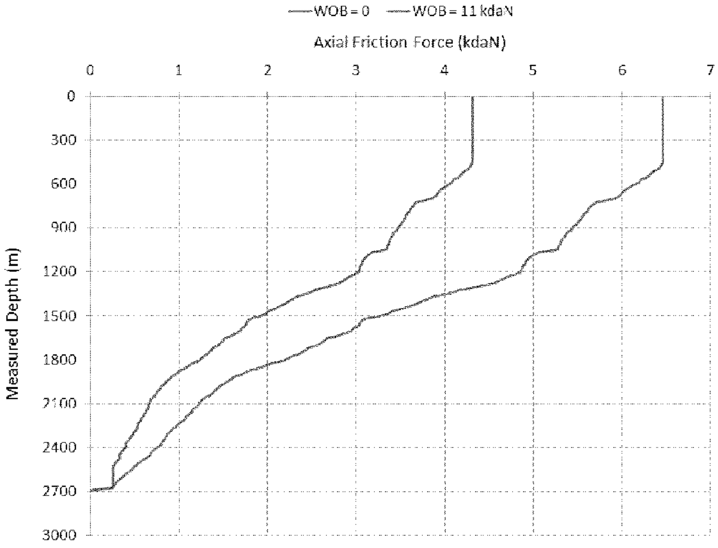

WOB = 0
WOB = 11 kdaN
Axial Friction Force (kdaN)
0
1
2
3
4
5
6
7
Measured Depth (m)
0
300
600
900
1200
1500
1800
2100
2400
2700
3000

Fig. 9

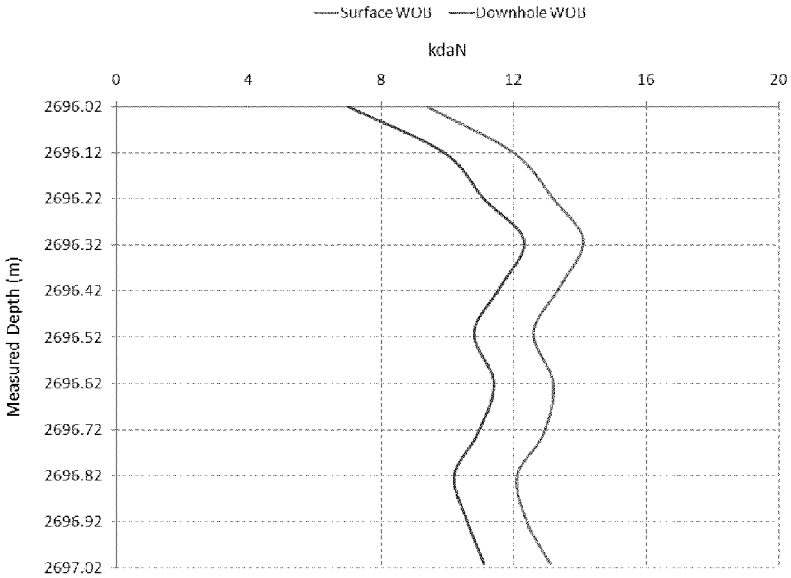

Surface WOB
Downhole WOB
kdaN
0
4
8
12
16
20
2696.02
2696.12
2696.22
2696.32
2696.42
2696.52
2696.62
2696.72
2696.82
2696.92
2697.02
Measured Depth (m)

Fig. 10

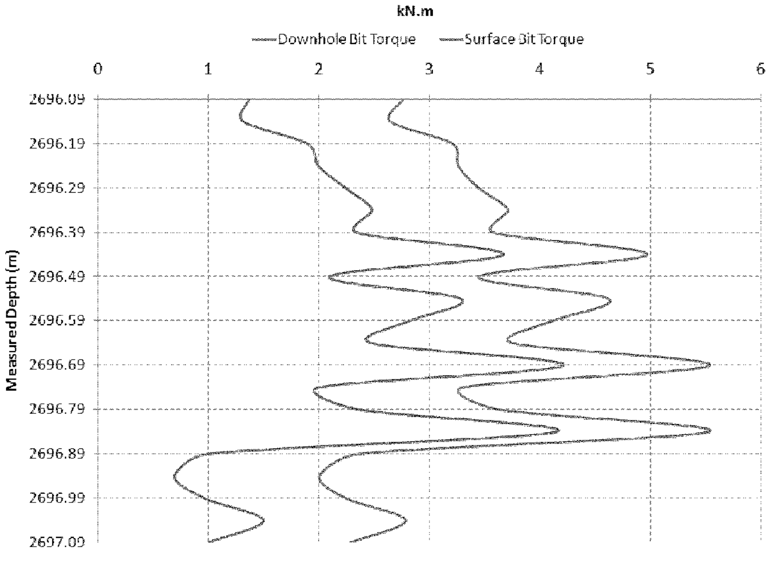

kN.m
Downhole Bit Torque
Surface Bit Torque
0
1
2
3
4
5
6
2696.09
2696.19
2696.29
2696.39
2696.49
2696.59
2696.69
2696.79
2696.89
2696.99
2697.09
Measured Depth (m)

Fig. 11

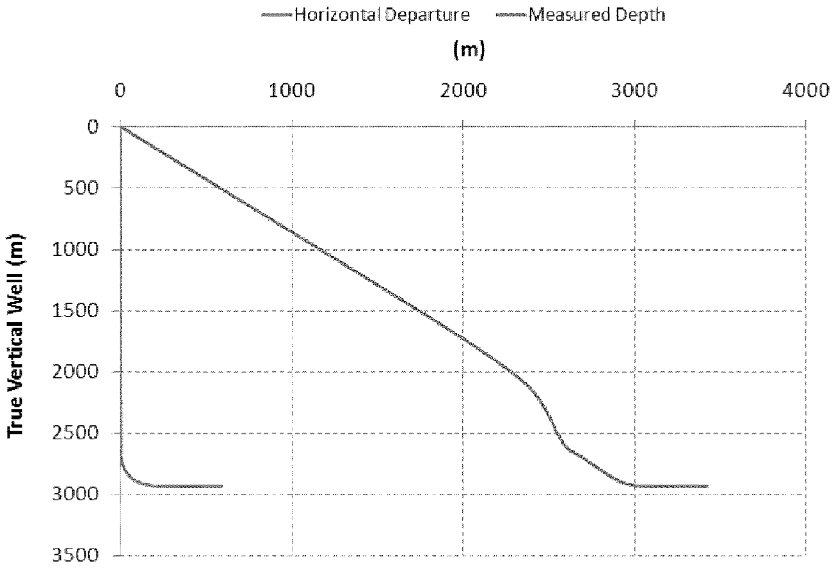

Horizontal Departure
Measured Depth
(m)
0
1000
2000
3000
4000
0
500
1000
1500
2000
2500
3000
3500
True Vertical Well (m)

Fig. 12

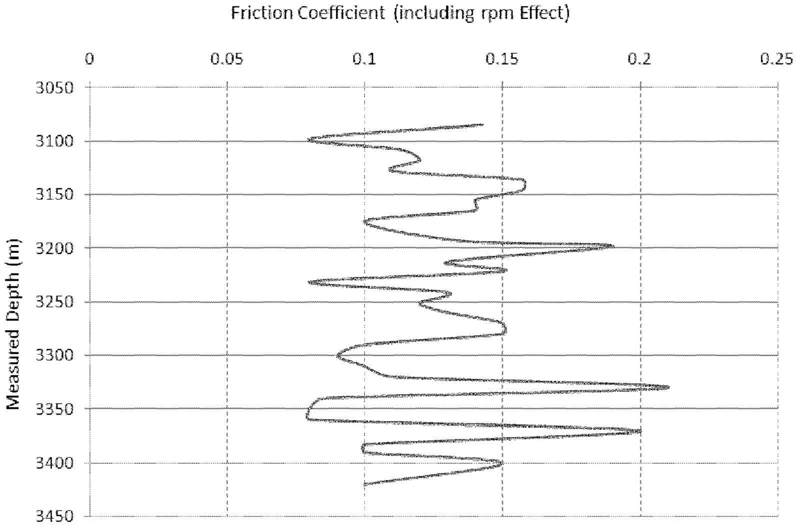

Friction Coefficient (including rpm Effect)
0
0.05
0.1
0.15
0.2
0.25
3050
3100
3150
3200
3250
3300
3350
3400
3450
Measured Depth (m)

Fig. 13

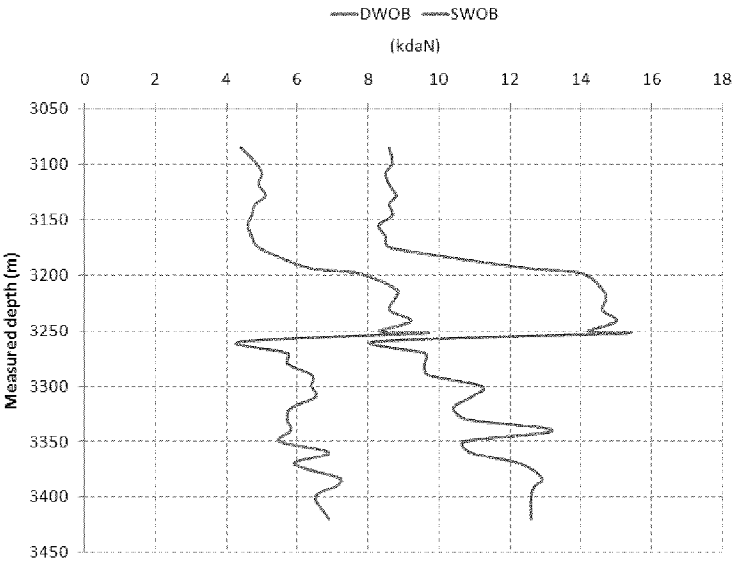

DWOB
SWOB
(kdaN)
0
2
4
6
8
10
12
14
16
18
3050
3100
3150
3200
3250
3300
3350
3400
3450
Measured depth (m)

Fig. 14

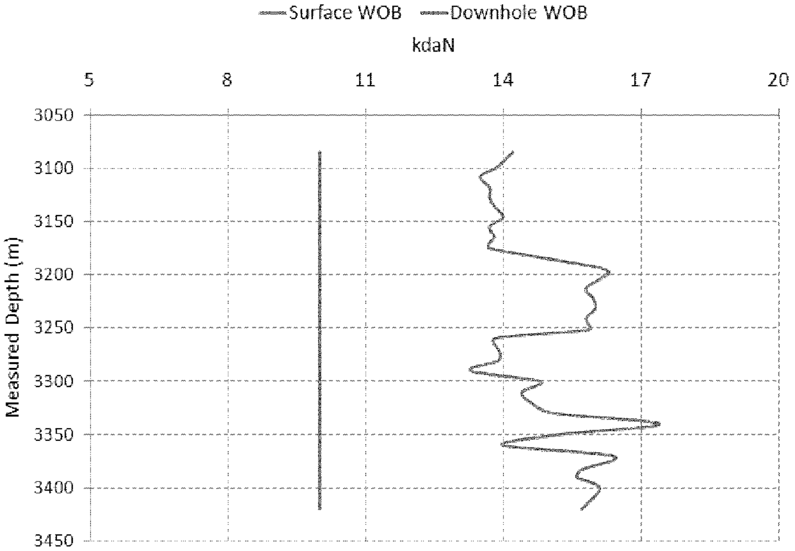

Surface WOB
Downhole WOB
kdaN
5
8
11
14
17
20
3050
3100
3150
3200
3250
3300
3350
3400
3450
Measured Depth (m)

Fig. 15

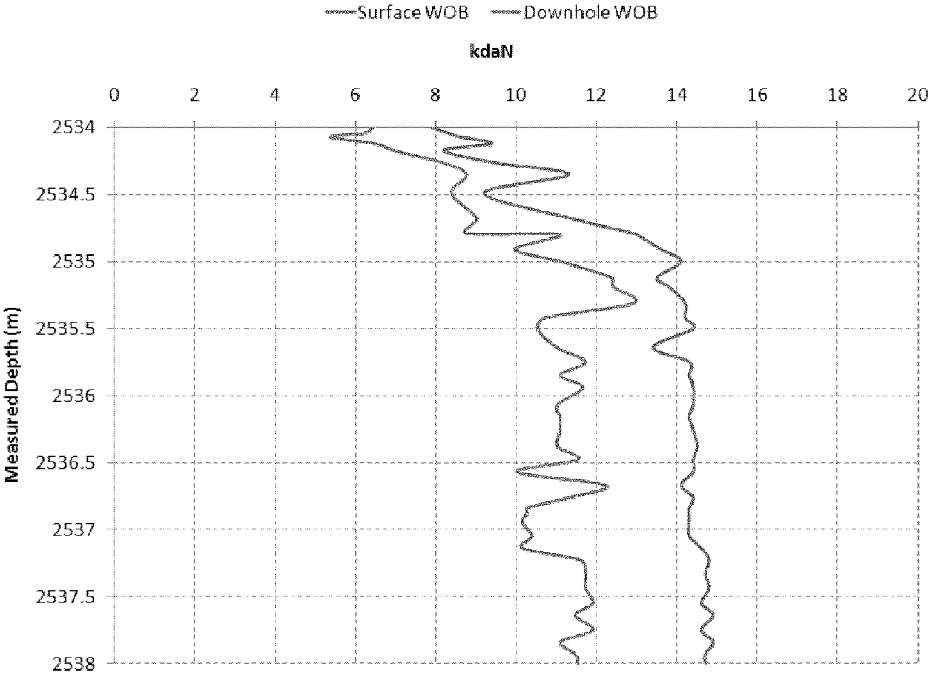

Surface WOB
Downhole WOB
kdaN
0
2
4
6
8
10
12
14
16
18
20
2534
2534.5
2535
2535.5
2536
2536.5
2537
2537.5
2538
Measured Depth (m)

FIG. 16

AUTODRILLER SYSTEM

FIELD

[0001] The invention is related to a controlling system for directional drilling of oil and gas wells.

BACKGROUND

[0002] In the drilling industry, in the absence of downhole measurements, the hookload and surface torque measurements are used to calculate weight on the bit and the bit torque. To apply weight on the bit, it is required to apply some portion of drillstring weight on the bit. The weight on the bit is calculated based on the difference between the hookload values when drillstring is off and on bottom. The surface weight on the bit could be the true value, if the well is vertical and the axial friction force between drillstring and the wellbore is negligible. When the well deviate from vertical straight line, the surface and downhole weight on the bit may not be the same due to axial friction force between drillstring and the wellbore. The same happens for bit torque calculation. The bit torque is estimated from difference between surface torque measurements while drilling bit is off and on bottom. An improved method of calculating downhole weight on bit and using this information in the drilling process is required.

SUMMARY

[0003] In an embodiment, there is provided a method of drilling or fracturing a formation, the method comprising drilling the formation with a drilling system that includes a drillstring and a bit, estimating a friction force on the drillstring, estimating a downhole weight on bit using a surface measurement and the estimated friction force and taking an action to change drilling of the formation based on estimated downhole weight on bit.

[0004] In a further embodiment, a method of drilling is provided for a drilling system having a drillstring and a bit. The method comprises estimating friction force on a drillstring using a friction model, estimating a downhole weight on bit and/or bit torque using surface measurements, and modifying drilling operation by modifying drilling parameters according to the estimated downhole weight on bit and/or bit torque. In an embodiment, the friction force is estimated according to the friction model and according to surface measurement conducted while the bit is off bottom. The surface measurement may be, for example, a hook load measurement. In an embodiment, the surface measurements used to estimate the downhole weight on bit and/or bit torque are hook load surface torque measurements. In an embodiment, the drilling parameter is one or more of surface torque, drillstring rotation rate or hook load.

[0005] In a further embodiment, the downhole weight on the bit may be estimated through steps comprising of: determining the static weight of drillstring; determining an axial friction coefficient including pipe rotation effect; determining the effect of downhole weight on the bit on value of axial friction force during drilling; and determining downhole weight on the bit using axial friction coefficient and surface hookload measurements. In an embodiment, if estimated weight on bit is non-zero and rate of penetration is not increasing, a founder point may be identified.

[0006] In an additional embodiment, downhole torque on bit may be determined by determining the rotational friction force while drilling bit is off bottom; determining the rotational friction coefficient including axial pipe movement effect from surface torque measurements while bit is off bottom; determining the effect of downhole weight on the bit on value of rotational friction force during drilling; and determining downhole bit torque by using rotational friction coefficient and estimated downhole weight.

[0007] The rotational coefficient including the drillstring axial movement effect, may for example be estimated while the bit is off bottom and there is no torque at the bit. Surface torque, for example, may be measured while the bit is moving downwardly and sufficiently close to bottom that the drillstring rotation at the point of measurement is the same as drillstring rotation in the formation to be drilled. Rotational friction force may be, for example, determined while bit is on bottom by using rotational friction coefficient and downhole weight on the bit. The estimated rotational friction force will be deducted from measured surface torque to find the downhole bit torque. The changes in downhole weight on the bit may change the rotational friction force which affects the value of the bit torque.

[0008] In a further embodiment, the static weight of drillstring may be calculated from a mud logging unit's data, the mud logging unit's data comprising survey data, drillstring specification, and local buoyancy factor at any bit depth.

[0009] In an embodiment, the axial friction coefficient including the drillstring rotation effect may be estimated using surface measured hookload determined when the bit is off bottom. The surface measured hookload may be determined while the bit is off bottom and has a drillstring rotation, and the bit is sufficiently close to bottom that the drillstring rotation is the same as the expected drillstring rotation in the formation to be drilled.

[0010] In an embodiment, to determine downhole weight on bit, hookload may be calculated by using axial friction coefficient and estimating the weight on the bit; comparing calculated hookload with measured hookload value; and, if the difference between calculated hookload and measured hookload value is negligible, the estimated downhole weight on the bit is taken as downhole weight on the bit. If the difference is not negligible, another value may be estimated for downhole weight on the bit. This procedure may repeated to determine the downhole weight on the bit.

[0011] In an exemplary embodiment, by calibrating the axial friction coefficient and the rotational friction coefficient from the surface measurement, a drilling problem may be identified. The drilling problem may be one or more of string sticking, and insufficient hole cleaning.

[0012] In an embodiment, the method described herein may be incorporated in an autodrilling system in which the autodrilling system automatically adjusts surface weight on bit utilized by the autodrilling system. The autodrilling system may display surface weight on bit from hook load measurements and estimated downhole weight on bit. In an embodiment, an action may be taken, for example determining when to pull the bit off the bottom, and pulling the bit off bottom.

[0013] In an embodiment, different equations are used, during drilling, to determine the downhole weight on bit depending on whether a part of the drillstring in a curved section is in compression or in tension.

[0014] In an embodiment, the method described herein may be used in sliding drilling employing a mud driven motor. In an embodiment, the estimated downhole weight on bit divided by pressure differential across the mud driven motor, given for example by the variable K, may be estimated. In an embodiment, K may be used to improve drilling performance.

[0015] The friction force is equal to the friction coefficient multiplied by the normal force which applies on contact surface area of the wellbore. The normal force may be a function of the buoyed unit weight of drillstring components, well geometry and the tensile force at the bottom of each drillstring element. For straight section such as inclined and horizontal sections, the normal force only depends on the buoyed unit weight of drillstring components, but in curved sections such as build-up, drop-off, the normal force depends on the buoyed unit weight of drillstring component and the tensile force which applies at the bottom of each drillstring element.

[0016] During drilling operation, the friction force acts against drillstring movement and rotation. In this case, when applying some weight on the bit, the tension force on drillstring elements located at the curved section will be reduced and friction force will be reduced consequently. According to an embodiment of a controlling system, an autodriller tool is used to calculate downhole weight on the bit and/or bit torque from surface hookload and/or torque measurements and use this information in the drilling process.

[0017] In an embodiment, time based hookload and surface torque data, the static weight of drillstring, SWDS, which can be calculated from vertical projection of drillstring at each measured depth and a three dimensional friction model to calculate friction forces and coefficients along drillstring may be programmed and integrated in a real-time autodriller controlling system and downhole weight on the bit and/or bit torque can be updated as long as surface data is being generated. The disclosed methods may be incorporated into a drilling system comprising a rig, a drill string connected downwardly into a borehole, and an autodriller system, the autodriller system being configured to carry out any one of the disclosed methods. Computer readable media, in non-transient form, and an autodriller system are configured to carry out the disclosed methods.

BRIEF DESCRIPTION OF THE DRAWINGS

[0018] Embodiments will now be described with reference to the figures, in which like reference characters denote like elements, by way of example, and in which:

[0019] FIG. **1** is a schematic illustration of drilling rig that shows the block and tackle system. The autodriller system is connected to deadline or any other hookload measurement system to estimate downhole weight on the bit.

[0020] FIG. **2** is the schematic description of drillstring moving downwardly in a vertical well while the bit is off and on bottom respectively. The axial and rotational friction forces between drillstring and the wellbore while bit is off and on bottom are negligible.

[0021] FIG. **3** shows the schematic of drillstring moving downwardly in a well with the geometry of vertical, build-up and the straight inclined sections. The axial and rotational friction forces in the build-up section will be decreased applying some weight on the bit.

[0022] FIG. **4** illustrates the drillstring along a horizontal well which is pushing toward the bottom. The axial and rotational friction forces in the curved section will be decreased while applying some weight on the bit.

[0023] FIG. **5** is a flowchart showing exemplary steps for calculation of downhole weight on the bit by using hookload measurements.

[0024] FIG. **6** is a flowchart showing exemplary steps for calculation of downhole bit torque by using the surface torque measurements.

[0025] FIG. **7** shows geometry of a drilled well which includes vertical, build-up, straight inclined and horizontal sections. The horizontal departure and measured depth have been plotted versus true vertical depth.

[0026] FIG. **8** compares tension and compression along drillstring when 11 kdaN weight applies on the bit.

[0027] FIG. **9** shows reduction in axial friction force along drillstring when 11 kdaN weight applies on the bit.

[0028] FIG. **10** shows the surface and downhole weight on the bit for 1 m drilled interval. The downhole weight on the bit is calculated as disclosed.

[0029] FIG. **11** shows the surface and downhole bit torque for 1 m drilled interval. The downhole torque at the bit is calculated as disclosed.

[0030] FIG. **12** shows geometry of a short bend horizontal well which include vertical, build-up and horizontal sections. The horizontal departure and measured depth have been plotted versus true vertical depth.

[0031] FIG. **13** illustrates friction coefficient versus measured depth during drilling operation for the interval between 3070 m to 3420 m. The estimated friction coefficients include effect of drillstring rotation.

[0032] FIG. **14** compares the surface and downhole WOBs for the drilled interval from 3070 m to 3420 m.

[0033] FIG. **15** shows surface WOB values versus measured depth during drilling operation when keeping 10 kdaN downhole weight on the bit.

[0034] FIG. **16** compares surface and downhole WOBs for a drilled interval from 2534 m to 2538 m. The downhole WOB was estimated using "K" value multiplication into differential pressure across downhole motor.

DETAILED DESCRIPTIONS OF PREFERRED EMBODIMENTS

[0035] The embodiments disclosed here provide mechanisms for improvement of drilling underground formations. In various embodiments, the mechanisms are implemented at least partially through an autodriller that controls drilling system components and that receives information on drilling conditions from drilling system components. The autodriller includes a processor that may be configured, by various means such as software, firmware and hardware, to calculate or estimate true downhole weight on bit (DWOB) by for example a) determining the static weight of drillstring; b) determining the axial friction coefficient including pipe rotation effect; c) determining the effect of downhole weight on the bit on value of axial friction force during drilling; d) determining downhole weight on the bit using axial friction coefficient and surface hookload measurements. Any of the various embodiments of the autodriller disclosed in this document may use finite element or difference methods or an analytical solution to do the calculations. The estimated DWOB may be used in a drilling simulation tool such as the Optimizer™ of Pason Systems Inc. to improve drilling performance.

[0036] The true DWOB produces the required or manufacturer recommended and/or simulated optimum or near optimum DWOB which may be used to produce improved rate of penetration (ROP).

[0037] In a further embodiment, the autodriller may be configured to calculate downhole torque on bit (DTOB) a) determining the rotational friction force while drilling bit is off bottom; b) determining the rotational friction coefficient including axial pipe movement effect from surface torque measurements while bit is off bottom; c) determining the effect of downhole weight on the bit on value of rotational friction force during drilling; d) determining downhole bit torque by using rotational friction coefficient and estimated downhole weight on the bit. The approach herein can use either finite element or difference methods or an analytical solution to do the calculations in the above approach. The true or estimated DTOB may be used for more accurate tooth wear prediction and used for real-time monitoring bearing wear, which gives drilling engineers reliable recommendation when to pull out the bit off the bottom and avoid bit failure and lost bearing in the hole.

[0038] The autodriller system may function independently of the drilling operator or driller ("black box" operation), and the driller sees the surface weight on the bit and then the system automatically adjust the surface WOB so that the down hole WOB can be accurate. The correct DWOB can give the optimal or near optimal WOB desired and other operating conditions for improvement of the overall or global ROP and minimize the $/ft.

[0039] In various embodiments, the autodriller may display both surface WOB (from hook load measurements) and down hole WOB (estimated from the method) for the driller. This will also benefit the driller get more accurate founder points (WOB when ROP no longer increase) when drill-off tests are being carried out.

[0040] The autodriller may learn from the surface measured data as a well is being drilled ahead by calibrating both axial and rotational friction coefficients. The friction coefficients can in addition help drilling engineers identify if drilling problems such as string sticking or insufficient hole cleaning is present, and may enable the drilling engineers to avoid pipe sticking.

[0041] The autodriller system may be used in both rotating and sliding drilling mode with a mud driven motor or with a rotary steerable system.

[0042] In rotary steerable drilling operations, no downhole weight on bit measurements may be required if the autodriller system calibrates itself from surface hookload measurements.

[0043] The autodriller may be used to calculate the static weight of drillstring using survey data, drillstring specification and local buoyancy factor at any bit depth, for example as provided by a mud logging unit on the rig site.

[0044] In some embodiments of the autodriller, the axial friction coefficient including the drillstring rotation effect is estimated by using the friction model from an improved surface measured hookload. For example, the last several off-bottom time based data points (excluding abnormal points) may be selected to calculate the friction coefficient using the hookload and SWOB of those points.

[0045] An improved measured hookload may for example be obtained while the bit is moving downwardly, and sufficiently close to the bottom that the drillstring rotation is for practical purposes the same as expected while drilling ahead in a new section.

[0046] In various embodiments of the autodriller, different equations may be used for calculating weight on bit or bit torque depending on whether a portion or element of the drillstring in a curved section is in compression or tension.

[0047] The autodriller may calculate the hookload by using axial friction coefficient and estimating the weight on the bit. The calculated hookload is compared with measured hookload value and if the difference between these values is negligible, the estimated value for weight on the bit is taken as downhole weight on the bit. If the difference is not negligible, another value will be estimated for weight on the bit and this procedure is repeated to get the true downhole weight on the bit.

[0048] For bit torque calculations, the rotational friction coefficient including the drillstring axial movement effect may be estimated by using the friction model from an improved measured surface torque while bit is off bottom and there is no torque at the bit. An improved measured surface torque may be found while the bit is moving downwardly and sufficiently close to the bottom that the drillstring rotation is the same as expected when drilling ahead in the next section. Using the rotational friction coefficient and estimated downhole weight on the bit from the autodriller, the estimated rotational friction force may be deducted from measured surface torque to find the downhole bit torque. The changes in downhole weight on the bit will change the rotational friction force which affects the value of the bit torque.

[0049] Use of the autodriller may provide an early real-time detection of the predicted trends (DWOB, friction factor) associated with some drilling dysfunctions (bit bouncing, stick-slip, lateral vibration, pipe sticking), which may enable the driller to take early corrective action to minimize escalation of the issue and therefore minimize the potential to induce coupling and catastrophic drill string integrity failures.

[0050] FIG. **1** shows the schematic diagram of a drilling rig. The drilling rig includes a derrick **10**, drillstring **12**, hoisting system, rotating system **16**, circulating system (not shown) and power system (not shown). Derrick **10** supports hoisting system and rotating system **16** which operate by power system (not shown). A drillstring **12** includes a series of drill pipe joints which connected downwardly from surface into the borehole **18**. A drilling bit **20** is attached to the end of drillstring that is called bottom hole assembly, BHA, **22**. The BHA does many functions such as providing weight on the bit, torque at the bit by downhole motor etc. The rotating system **16** may include the rotary table **16** or top drive (not shown) to rotate drillstring **12** at the surface to rotate drilling bit **20** at the bottom where it impacts the formation being drilled. The hoisting system includes drawworks **24** and block and tackle system **14**. The drawworks **24** control the weight on the drilling bit **20** during drilling operation and raise and lower drillstring **12** through the wellbore. The block and tackle system **14** comprised of crown block **26**, travelling block **28** and drilling line **30**. If the number of drilling lines in the block and tackle system **14** increase, the tension in drilling lines **28** will decrease which provide the higher load capacity for the hoisting system.

[0051] The drilling line **30** is connected to drawworks **24** from one end which is called fast line **32** and from other end connected to deadline anchor or wheel **34** which is called the dead line **36**. To measure the loads applied on the hook **38** by drillstring weight **12** and movement through the wellbore **18**, the hydraulic cell **40** is connected to deadline **36** to measure the tension in drilling line **30**. For hookload measurement, the measured tension in the deadline should be multiplied by the number of drilling line **30** between the sheaves **42** in block and tackle system **14**. The tension in the deadline **36** is not true value due to friction between the drilling line **30** and the sheaves **42**. The true value can be calculated by considering the friction in block and tackle system **14**. When some weight of drillstring **12** applies on the drilling bit **20**, a reduction in deadline **36** tensions is observed. In drilling industry based on industry method this reduction is considered as surface weight on the bit which is not usually equal to downhole weight on the bit. The real-time hookload data should be transferred into autodriller system **44** for further treatment to obtain the downhole weight on the bit. Also autodriller can calculate the downhole bit torque which results from surface rotation. The real time surface torque should be sent to autodriller system **44** for calculating downhole torque at the bit. After calculating downhole weight on the bit and bit torque, they will be available for users **46** for different purposes such as drilling optimization and real-time drilling analysis.

[0052] FIG. **2*a*** illustrates in schematic way a drillstring **12** in a vertical wellbore **46** with a hook **38** at the top. The drillstring is hung from the hook **38** which mostly consists of drillpipe **48** and the lower end of the drillstring called bottom hole assembly **50** that carries a drilling bit **20**. The borehole is being drilled and extends downwardly from the surface. In FIG. **2*a*** the drilling bit is off bottom and entire load of drillstring applies on the hook **38**. In this condition, the entire drillstring will be in tension **52**, the minimum tension is at the drilling bit and maximum tension will be at the surface. Also there is negligible contact between drillstring **12** and the vertical wellbore **46** during drillstring **12** rotations which means the friction force can be neglected. For a drillstring element **54** in a vertical wellbore **46**, the tension force balance can be written as follow:

$$F_{top}=F_{bottom}+\beta\times \mathrm{SW} \tag{1}$$

Where

[0053] F_{top}: Force at the top of drillstring element

[0054] F_{bottom}: Force at the bottom of drillstring element

[0055] β: Buoyancy factor

[0056] SW: Static weight of the drillstring element

[0057] To calculate the tension at the hook **38**, drillstring **12** is divided to n number of elements and calculation starts from drilling bit **20** to the surface. Please note, in underbalanced drilling, the buoyancy factor is dynamic parameter which will vary along the drillstring **12** by changing the pressure, temperature, drilling cutting rate and gas influx etc.

[0058] FIG. **2*b*** shows the drillstring in on bottom position. Once some weight of drillstring applies on drilling bit, WOB **56**, some length of drillstring will be in compression **58** beginning from bit to neutral point **60**. In the neutral point the compression switches to tension **62** for the rest of drillstring to the surface. Obviously, the hook load **64** will be smaller once the weight applies on drilling bit. In this scenario, the weight on the bit **56** is recorded from the difference between the hook load values when drilling bit is off and on bottom. The calculated surface weight on the bit **56** will be the same as what applies downhole by neglecting the minor friction in the vertical well **46**. The force balance at each element can be written as follow:

$$F_{top}=(F_{bottom})_{DWOB}+\beta\times \mathrm{SW} \tag{2}$$

[0059] When the bit is off bottom, the surface torque **66** value is negligible due to minor contact between drillstring and the vertical wellbore **46**. Once the bit goes on bottom for drilling and applies weight on the bit **56**, an increase in value of surface toque **70** can be observed due to torque on the bit **68**. To calculate bit torque **68** from surface measurements, the difference between surface torques **66** & **70** while bit is off and on bottom should be calculated.

[0060] FIG. **3*a*** shows a drillstring in a deviated wellbore which consist of vertical **72**, build-up **74** and straight inclined **76** sections. In the build-up **74** and straight inclined **76** sections, there is contact between drillstring and the wellbore which results in friction force **78**&**80** against the pipe movement. The nature of friction in these two sections is different. In this scenario, the bit is off bottom and entire drillstring is in tension **82**. When the axial friction forces calculations start from drilling bit upwardly, in the straight inclined section **76**, the tension will not have any contribution in axial friction force **78**. But when build up section **74** begins, the tension at this point will have great contribution in the friction force **80**. It means, for a drillstring element in the straight inclined **76**, the friction force **78** only depends on the weight of element which applies normally on the contact area but in the build-up section **74**, the friction force **80** mostly depends on the tension at the bottom of the element and also the normal weight of drillstring element. The following is the general force balance for each element along drillstring.

$$F_{top}=F_{bottom}+\beta\times \mathrm{SW}-\mathrm{Friction}_{weight}-[\mathrm{Friction}_{tension}\ \mathrm{or}\ 0] \tag{3}$$

In this equation, the axial friction force term related to tension will be zero if the element is in the straight section **76**. Also, if the pipe element is in vertical section **72** both terms related to friction will be vanished.

[0061] In FIG. **3*b*** some weight of drillstring applies on drilling bit which means reduction in tension **84** along drillstring. The reduction in tension **84** has considerable effect on axial friction force **86** in the build-up section **74** but not straight inclined section **76**. If applying the weight on the bit causes drillstring to be in compression **88** in the curved section **74**, the axial friction force **86** for that part will not be another function of the tension **84**. The equation (4) represents the force balance when applying weight on the bit **90**.

$$F_{top}=(F_{bottom})_{DWOB}+\beta\times \mathrm{SW}-\mathrm{Friction}_{weight}-[(\mathrm{Friction}_{tension})_{DWOB}\ \mathrm{or}\ 0] \tag{4}$$

In equation (4), the friction force **86** in the curved section **80** is affected by downhole weight on the bit **90** which is subscripted by DWOB. It should be mentioned the axial friction force **86** changes in the curved section will change the overall friction and surface hookload **92** value consequently.

[0062] The same story will happen for surface torque **94** measurements. The rotational friction forces **96**&**98** between drillstring and wellbore depend on normal weight of drillstring element and tension along drillstring. Applying weight on the bit **90** reduces the tension **84** along drillstring which affects the value of rotational friction force in the curved section **98**. Equation (5) shows the torque for an element in drillstring while bit is off bottom and there is no weight on the bit **90**.

$$\text{Torque}_{top}=\text{Torque}_{bottom}+\text{Torque}_{weight}+[\text{Torque}_{tension}\text{ or }0] \quad (5)$$

[0063] To calculate the surface torque **94**, drillstring is divided to many numbers of elements and calculation starts from drilling bit to the surface. Once the element is in straight inclined section the torque will be the function of element weight only. When the element is in curved section **74** and the drillstring is in tension **84**, the torque will depend on mostly tension **82** and less on weight. For surface torque **100** when drillstring goes on bottom, the tension **84** along drillstring will change which affects the value of rotational friction force **102** in the curved section **74** as well. Also, the value of torque on the bit **106** will be added as shown in equation (6). The rotational friction force **104** in the straight inclined section **76** will not change.

$$\text{Torque}_{top}=\text{Torque}_{bottom}+\text{Torque}_{bit}+\text{Torque}_{weight}+[(\text{Torque}_{tension})_{DWOB}\text{ or }0] \quad (6)$$

[0064] FIG. 4*a* shows a horizontal well which includes vertical **108**, build-up **110** and horizontal **112** sections. The drillstring is off bottom and pushing toward the bottom. The axial friction force **114** is acting against the drillstring movement tendency. To push the pipe in the horizontal section **112**, it is necessary to have some heavy drillpipes **118** in vertical **108** and build-up **110** sections for providing sufficient drive to push drillstring in the horizontal **112** section. The axial friction force **116** in horizontal section **112** is function of the weight of drillstring which normally applied on wellbore contact area. When drilling bit is off bottom and drillstring is pushing toward the bottom, some part of heavy drillpipe **118** will be in compression **120** due to axial friction force **116** in the horizontal **112** section. In this scenario, the axial friction force **114** in the curved section which is in compression **120** is only function of weight of drillstring element. Above neutral point **122**, the drillstring will be in tension **124** and axial friction force **114** will be depends on the normal force and tension force for each element. If the element is in horizontal **112** section, the axial friction force **116** will depend only to weight of the element. The equation (3) can be applied for the horizontal well drilling for hookload calculation **126** when drilling bit is off bottom and moving toward the bottom. The friction force may be estimated according to a friction model using surface measurements conducted while the bit is off bottom.

[0065] When some weight applies on the bit **128** as shown in FIG. 4*b*, the bigger length of drillstring goes in compression **130**. In this case, usually the most of axial friction force **132** in the build-up section **110** will no longer depend on the tension. The equation (4) can be applied for hook load **134** calculations when drilling bit is on bottom: the hook load may be measured when the bit is off bottom and incorporated into the calculation of friction force.

[0066] In FIG. 4*a* once drillstring is off bottom, there is not bit torque **136**. The rotational friction force is related to build-up **110** and horizontal **112** sections. In horizontal section **112** the rotational friction force **138** is the function of normal force which is applied by the weight of drillstring element. In build-up **110** section while drillstring element is in compression **120**, the rotational friction force **140** is only the function of weight but if drillstring is in tension **124** the rotational friction force **140** is the function tension and weight. That is, different equations are employed to determine the downhole weight on bit depending on whether a part of the drillstring in a curved section is in compression or tension. Once drilling bit goes on bottom for drilling, applying weight on drilling bit **128** causes some reduction in tension **124** along drillstring which affects the value of rotational friction force **142** in the build-up **110** section. During drilling operation, there are some variations in bit torque **136** and rotational friction force **142** in the curved **110** section which should be estimated from surface torque measurements **144** by using present invention method.

[0067] FIG. **5** is a general flowchart showing the steps how "autodriller" can estimate downhole weight on the bit from surface measurements. The first step is determining the static weight of drillstring, SWDS **146**. To calculate the SWDS **146** the following information are required at any measured depth:

[0068] survey point data, inclination

[0069] drillstring components unit weights

[0070] drilling fluid density to calculate the buoyancy factor.

[0071] There are standard equations which are used to calculate the static weight of drillstring **146**. When the bit is off and then on bottom, a short length (the maximum is the length of a stand) will be added to drillstring and the positions of other components will be changed as well. For this reasons, it is required to update the SWDS **146** when drilling bit goes on bottom for further drilling. Also, in under balanced drilling, the drilling fluid density is variable; therefore the local buoyancy factor should be calculated for each element and is not constant anymore.

[0072] The second step is determining when the bit is off or on bottom **148**. During drilling operations, the mud logging unit records all necessary field data. The measured depth and bit depth data will be used to know when the bit is off and on bottom **148** and also bit is moving upward or downward. Here, the measured depth corresponds to final drilled depth at any time of calculations. When the bit is off bottom and drillstring is moving downwardly, the measured hookload **150** should be compared with SWDS. If difference between values **152** is negligible, it means there is no axial friction force and the well geometry is vertical **154**. When the bit goes on bottom, some weight of drillstring applies on the bit and a reduction in the hookload will be observed. The reduction in the hookload is taken as downhole weight on the bit, DWOB **156**. Therefore the DWOB can be calculated directly from surface hookload measurements for a vertical well when drilling bit is off and on bottom.

[0073] If difference between measured hookload and SWDS is not negligible, the difference between these two values gives the axial friction force **158** between drillstring and the wellbore. It is very critical to select the best measured hookload value while the bit is off bottom because the axial friction coefficient **160** is estimated based on it. The estimated axial friction coefficient **160** will be used for estimating the DWOB **162** when the well is deviated and there is considerable axial friction force between drillstring and the wellbore. Hence, the hook load is measured when the bit is off bottom and used in the estimation of the axial coefficient including the drillstring rotation effect. Further, the surface measured hookload may be determined while the bit is off bottom and has a drillstring rotation and when the bit is sufficiently close to the bottom that the drillstring rotation is the same as the expected drillstring rotation in the formation to be drilled. Therefore the followings conditions are considered to select the best measured hookload value while the bit is off bottom:

[0074] The hookload is chosen when the bit is moving downwardly very close to bottom hole. In this situation the drillstring movement is very slow like on bottom situation while drilling bit is penetrating a formation.

[0075] The drillstring rotation speed is the same as planned one while the bit goes on bottom for further penetration. The effect of pipe rotation is included in axial friction coefficient

[0076] By knowing the axial friction force and having a reliable friction model, the axial friction coefficient **160** which includes the drillstring rotation effect will be estimated. This axial friction coefficient **160** will be used for DWOB **162** calculation when the bit goes on bottom for further drilling.

[0077] The next step is when the bit depth and the measured depth **164** are equal which means the bit is on bottom. In this situation, the measured hookload **166** is known, as it is measured from the surface, and the hookload **168** could be calculated as well. To calculate the hookload **168**, the SWDS **146**, axial friction force and DWOB should be known. As discussed, the SWDS **146** is obtained directly from aforementioned standard equations. The DWOB **162** is estimated and the axial friction force will be calculated based on estimated DWOB. Here, to obtain the best value for DWOB **162**, some value should be estimated close to surface weight on the bit and applies in friction model to see its effect on value of axial friction force. If the difference between measured and calculated hookload is negligible **170** then the value is taken as DWOB **162**. Otherwise another value is chosen and repeat the calculation. This loop will be continued until the difference between calculated and measured values becomes negligible.

[0078] The estimate of downhole weight on bit and bit torque can be used to modify drilling process. This may comprise taking an action to change drilling of the formation based on the estimate of DWOB or bit torque. The modification of the drilling parameter during drilling is carried out by the autodriller system **44** and thus modifies the drilling process according to the modification of the drilling parameter. In a further embodiment, the autodriller displays surface WOB from hook load measurements and estimated downhole weight on bit. In an additional embodiment, when estimated weight on bit is non-zero and the rate of penetration is not increasing, the auto-driller may identify a founder-point.

[0079] The autodriller may learn from surface measured data during drilling by calibrating both axial and rotational friction coefficients from the surface measurement. The axial and rotational friction coefficients may be used to identify a drilling problem. The friction coefficients may additionally help identification of drilling problems such as string sticking or insufficient hole cleaning, and may be used in avoiding pipe sticking. In another embodiment, the action taken by the autodriller may be determining when to pull the bit off the bottom and then pulling the bit off the bottom.

[0080] The instructions for carrying out the processes described here may be contained in non-transient form on computer readable media. When saved to a computer forming part of the autodriller system, the instructions configure the autodriller system to carry out the instructions. The drilling system may comprise a rig, a drill string connected downwardly into a borehole, an autodriller system, the autodriller system being configured to carry out instructions of the processes described herein.

[0081] FIG. **6** is a general flowchart showing the steps how "Autodriller" can estimate bit torque **172** when rotating from the surface. The procedure is mostly similar to downhole weight on the bit **162**. That is, in a preferred embodiment, the process is similar to calculating downhole weight on a bit: determine the rotational friction force while the drilling bit is off bottom; determine the rotational friction coefficient including axial pipe movement effect from surface torque measurements while bit is off bottom; determining the effect of downhole weight on the bit on value of rotational friction force during drilling; and determining downhole bit torque by using rotational friction coefficient and estimated downhole weight. An estimate of rotational friction force while the bit is on bottom is estimated by using the rotational friction coefficient and downhole weight on the bit. The estimated rotational friction force will be deducted from measured surface torque to find the downhole bit torque. The changes in downhole weight on the bit will change the rotational friction force which affects the value of the bit torque. In one embodiment, the rotational friction coefficient including the drillstring axial movement effect may be estimated while the bit is off bottom and there is no torque at the bit. Note that different equations may be used when determining downhole torque on bit depending on whether a part of the drillstring in a curved section is in compression or tension.

[0082] The estimated downhole weight on the bit **162** in previous section is used for downhole bit torque calculation **172**. In the first step, the bit depth should be compared with measured depth **174** to see the drilling bit is on bottom or off bottom. When drilling bit is off bottom and the value of the measured surface torque is negligible **176**, it means the drilling well is vertical and there is negligible rotational friction force **178**. When drilling bit goes on bottom for further drilling, the measured surface torque almost corresponds to downhole bit torque **172**. If the measured surface torque is not negligible while bit is off bottom, it means the well is not vertical and there is rotational friction force against drillstring rotation **180**. As discussed before, the best selected data is when the bit is off bottom and is moving downwardly close to the bottom with the same pipe rotation as planned for drilling. From the rotational friction force **180** while bit is off bottom and using a reliable friction model, the rotational friction coefficient **182** may be estimated for next steps.

[0083] When the bit goes on bottom for further drilling, the measured surface torque **184** can be read. The downhole weight on drilling bit, DWOB **162**, will affect value of rotation friction force **186** due to changes in tension along drillstring. Using DWOB **162** and rotational friction coefficient **182** in a reliable friction model yields the rotational friction force during drilling operation which changes whit the changes in DWOB **186**. The final step is calculating the downhole bit torque due to surface rotation by subtracting the rotational friction force from surface torque measurements **172**.

EXAMPLE APPLICATION

[0084] A friction model is applied to estimate DWOB and bit torque during drilling operations. When drillstring specification, survey data and friction coefficient are specified, the calculation begins at the bottom of drillstring and continues stepwise upwardly. Each drillstring element contributes small load on hookload and surface torque. The force and torque balance on drillstring element when the bit is off bottom can be written as follows:

$$F_{top} = \beta w \Delta L\left(\cos\alpha \text{ or } \frac{\sin\alpha_{top} - \sin\alpha_{bottom}}{\alpha_{top} - \alpha_{bottom}}\right) - \mu \times \beta w \Delta L\left(\sin\alpha \text{ or } \frac{-\cos\alpha_{top} + \cos\alpha_{bottom}}{\alpha_{top} - \alpha_{bottom}}\right) + \left(F_{bottom} \text{ or } F_{bottom} \times e^{-\mu|\theta|}\right) \tag{7}$$

[0085] However the following might be used when the drillstring is in compression in the curved section

$$F_{top} = \beta w \Delta L \cos\left(\frac{\alpha_{top} + \alpha_{bottom}}{2}\right) + \mu\left[\begin{array}{c}\left(F_{bottom}(\phi_{top} - \phi_{bottom})\sin\left(\frac{\alpha_{top} + \alpha_{bottom}}{2}\right)\right)^2 + \\ \left(F_{botom}(\alpha_{top} - \alpha_{bottom}) + \beta w \Delta L \sin\left(\frac{\alpha_{top} + \alpha_{bottom}}{2}\right)\right)^2\end{array}\right]^{0.5} + F_{bottom} \tag{8}$$

For the torque at each element:

$$T_{top} = T_{bottom} + \mu \times r \times \beta w \Delta L \times \left(\sin\alpha \text{ or } \frac{-\cos\alpha_{top} + \cos\alpha_{bottom}}{\alpha_{top} - \alpha_{bottom}}\right) + \left(0 \text{ or } \mu \times r \times F_{bottom} \times |\theta|\right) \tag{9}$$

Corresponding to equation (8) the torque can be expressed as the following:

$$T_{top} = \mu \times r \times \left[\begin{array}{c}\left(F_{bottom} \times (\phi_{top} - \theta_{bottom}) \times \sin\left(\frac{\alpha_{top} + \alpha_{bottom}}{2}\right)\right)^2 + \\ \left(F_{botom} \times (\alpha_{top} - \alpha_{bottom}) + \beta \times w \times \Delta L \times \sin\left(\frac{\alpha_{top} + \alpha_{bottom}}{2}\right)\right)^2\end{array}\right]^{0.5} + T_{bottom} \tag{10}$$

Where

[0086] w: Unit weight of drillstring element

[0087] ΔL: Length of the drillstring element

[0088] α: Inclination

[0089] μ: Friction coefficient

[0090] θ: Dogleg angle

[0091] r: Tool joint radius

[0092] In the equations (7), the terms in order for an element correspond to static weight, the axial friction force caused by the weight and axial friction force caused by the tension at the bottom. In the equations, if the inclination at the top and bottom of an element is equal, the element is considered as straight and the first term in each bracket will be used otherwise it will be considered as a curved element and second term will be used. Equation (8) is for compressed drillstring in the curved section

[0093] Also for bit torque calculation, equations (9) (10) are used.

[0094] A drilled well was selected as shown in FIG. **7** to illustrate how autodriller can estimate the downhole weight on the bit and bit torque. The well geometry includes two build-up sections, straight and horizontal sections. When drill bit is at depth 2700 m, the entire drillstring was at tension. Applying 11 kdaN weight on the bit causes some portion of drillstring starting from bit to go in compression and reduce the tensile force for the rest as shown in FIG. **8**. This reduction in tension along drillstring has effect on value of friction force as shown in FIG. **9** as much as 2.15 kdaN. In the example, the downhole weight on the bit has effects only on the friction forces in those build-up sections. As discussed before, the weight on the bit will reduce the friction force in the curved sections which affect axial and rotational friction force as well. The sample calculation has been shown as follow:

[0095] When the bit is at depth 2695.6 m, almost 0.4 m off bottom and moving downwardly, the axial friction coefficient including pipe rotation effect is estimated as follow:

$$\text{Static Weight of Drill String} = 874.4\ kN$$

$$\text{Bit Depth} = 2694.6\ \text{m}$$

$$\text{Measured Depth} = 2696.02\ \text{m}$$

$$\text{Bit Depth} \leq \text{Measured Depth} \rightarrow [\text{Hook } Load_{Off}]_{Measured} = 810.2\ kN$$

$$[\text{Axial Friction Force}]_{Off\ Bottom} = 874.4 - 810.2 = 64.4\ kN \xrightarrow{U \sin g\ Friction\ Model} \mu_{axial} = 0.095\ \text{(pipe rotation included)}$$

[0096] The axial friction coefficient including the pipe rotation effect will be used when drillstring goes on bottom for drilling. The axial friction coefficient can be updated for each wiper trip periodically and used for upcoming sections. The estimated axial friction coefficient is used in a friction model to calculate the hookload.

Bit Depth=2696.02 m

Measured Depth=2696.02 m

Bit Depth=Measured Depth→[Hook $\text{Load}_{On}]_{Measured}$=760 kN

SWOB=**94** kN

[0097] The different values for downhole weight on the bit should be estimated until the difference between the measured and calculated hookloads become negligible. When the difference is acceptable, the final estimated value for downhole weight on the bit will be chosen.

DWOB, kN	$[\text{Hookload}]_{Calculated}$, kN	$[\text{Hookload}]_{Calculated}$ − $[\text{Hookload}]_{Measured}$ ≤ 1.00 kN
SWOB = 94	739.5	20.50
90	742.9	17.10
85	746.9	13.10
80	751	9.00
75	745	5.00
DWOB = 70	759	1.00

[0098] The FIG. **10** compares surface and downhole weight on the bit values for one meter drilled interval using the present invention method.

[0099] For surface torque measurement, the increment in surface torque when drilling bit goes on bottom for drilling consider as bit torque. The reduction in tension has a considerable impact on value of rotational friction force which should be counted for bit torque calculations. In this field example, when the bit is off bottom and moving downwardly with the same RPM as planned for drilling, the measured surface torque is as follow:

Bit Depth=2695.6 m

Measured Depth=2696.09 m

Bit Depth≤Measured Depth→[Surface Torque]$_{Measured}$=13.5 kN.m

[0100] The Measured surface torque is equal to rotational friction force. By using a reliable friction model, the rotational friction coefficient can be estimated:

$$[\text{Rotational Friction Force}]_{off\ bottom} = 13.5\ kN \cdot \text{m} \xrightarrow{U\ \sin\ g\ Friction\ Model} \mu_{Rotational} = 0.245$$

[0101] When drilling bit is on bottom and some weight applies on drilling bit, the surface torques measurement increase due to interaction between drilling bit and rock surface. The difference between surface torque measurements for off and on bottom drilling positions consider as surface bit torque as shown as follow:

$\lfloor\text{Surface Torque}_{on\ bottom}\rfloor_{Measured}$=14.86 kN.m→Surface Bit Torque=14.86−13.5=1.36 kN.m

But when some weight applies on the bit, the tension along drillstring will be reduced and rotational friction force will be reduced as well which should be consider for bit torque measurements.

$$[\text{Rotational Friction Force}]_{on\ bottom} \xrightarrow{DWOB=120\ kN} 12.34\ kN$$

The downhole torque at the bit can be estimated as follow:

$$\text{Downhole Bit Torque} = \lfloor\text{Surface } Torque_{on\ bottom}\rfloor_{Measured} - \lfloor\text{Rotational Friction Force}\rfloor_{on\ bottom} = 14.86 - 12.34 = 2.52\ kN \cdot \text{m}$$

The estimate of bit torque can be used to modify a drilling parameter. The drilling parameter can be, for example, surface torque, drillstring rotation rate or hookload.

[0102] FIG. **11** compares the surface and downhole bit torque for one meter interval by considering effect of downhole weight on the bit on rotational friction force.

[0103] FIG. **12** is well geometry of another example which verifies the application of the current method. 350 m drilled interval has been selected to estimate downhole weight on the bit from hookload measurements. As discussed previously, the friction coefficient should be estimated and updated during drilling operation. FIG. **13** illustrates the plot of friction coefficient including drillstring rotation effect versus measured depth for this 350 m drilled interval to use for downhole weight on the bit estimation. FIG. **14** compares the surface and downhole weight on the bit which estimated by using autodriller system. To apply a constant weight on the bit as much as 10 kdaN, the autodriller estimate the value of surface weight on the bit versus measured depth as shown in FIG. **15**.

[0104] Also, this autodriller system can be used for sliding drilling which is used for directional or horizontal drilling. This autodriller system may be used in sliding drilling using a mud driven motor, where the drilling bit rotated by mud motor instead of rotating the drillstring from surface. The mud motor is powered by the fluid differential pressure. There is a certain relationship between differential pressure and DWOB which can be found by using present system. Here "K" value is used to represent the ratio of DWOB to differential pressure which can be found during rotating time. When sliding begins, a new DWOB can be predicted with the product of K and differential pressure. As an example, the average value for "K" is estimated during rotating time as much as

$$0.67\frac{kN}{kPa}$$

for a drilled interval. The differential pressure was multiplied by "K" value to estimate DWOB as shown in FIG. **16**. The autodriller may use K to improve drilling performance.

[0105] In all of example application, a newly developed analytical model was used to calculate the axial and rotational frictions between drillstring and the wellbore. This model can be replaced by any other analytical and numerical models to calculate axial and rotational friction forces for downhole weight on the bit and bit torque estimation.

[0106] For example, using finite element method, an attempt has been made to calculate friction forces between wellbore and drillstring. In this modeling, the drillstring can be thought of as a very long rotor of variable geometry constrained within a continuous journal bearing of variable clearance and rigidity. The equations of motion are based on Hamilton's principle

$$[M]\{\ddot{U}\}+[C]\{\dot{U}\}+[K]\{U\}=\{F\} \tag{11}$$

Where the vectors {U}, {$\dot{U}$}, {$\ddot{U}$} and {F} represent generalized displacements, velocities, accelerations and forces, respectively. Also the matrixes M, C and K represent mass, damping and stiffness respectively. The forces include gravity, unbalanced mass and frictions with the wellbore. Wilson-θ, a kind of numerical method, is used to get the solution to the above equation. Based on the equation, numerical solution method and appropriate boundaries, a finite element analysis (FEA) program is developed to do the calculation and analysis of torque and drag under different drilling modes with vertical, directional and horizontal wells.

[0107] Immaterial modifications may be made to the embodiments described here without departing from what is covered by the claims. In the claims, the word "comprising" is used in its inclusive sense and does not exclude other elements being present. The indefinite article "a" before a claim feature does not exclude more than one of the feature being present. Each one of the individual features described here may be used in one or more embodiments and is not, by virtue only of being described here, to be construed as essential to all embodiments as defined by the claims.

1. A method of drilling a formation, the method comprising:

drilling the formation with a drilling system that includes a drillstring and a bit;

estimating a friction force on the drillstring;
estimating a downhole weight on bit using a surface measurement and the estimated friction force; and
taking an action to change drilling of the formation based on estimated downhole weight on bit.

2. The method of claim **1** in which estimating a friction force on the drillstring comprises applying a friction model.

3. The method of claim **1** in which the action comprises modifying drilling by modifying a drilling parameter.

4. The method of claim **1** in which the friction force is estimated according to the friction model and according to a first surface measurement conducted while the bit is off bottom.

5. The method of claim **4** in which the first surface measurement is a hook load measurement.

6. The method of claim **5** in which the surface measurement is a hook load measurement.

7. The method of claim **1** in which the drilling parameter is one or more of surface torque, drillstring rotation rate, hook load and mud weight.

8. The method of claim **1** in which estimating the downhole weight on the bit comprises:
(a) determining the static weight of drillstring;
(b) determining an axial friction coefficient including pipe rotation effect;
(c) determining the effect of downhole weight on the bit on value of axial friction force during drilling; and
(d) determining downhole weight on the bit using axial friction coefficient and surface hookload measurements.

9. The method of claim **1** incorporated in an autodrilling system in which the autodrilling system automatically adjusts surface WOB utilized by the autodrilling system.

10. The method of claim **1** in which taking an action comprises the autodrilling system displaying surface WOB from hook load measurements and estimated downhole weight on bit.

11. The method of claim **1** further comprising identifying a founder point where estimated weight on bit is non-zero and rate of penetration is not increasing.

12. The method of claim **1** further comprising calibrating the axial friction coefficient and the rotational friction coefficient from the surface measurement and identifying a drilling problem.

13. The method of claim **12** in which the drilling problem is one or more of string sticking and insufficient hole cleaning.

14. The method of claim **8** wherein the static weight of drillstring is calculated using survey data, drillstring specification and local buoyancy factor at any bit depth which are given by mud logging unit on the rig site.

15. The method of claim **8** wherein the axial friction coefficient including the drillstring rotation effect is estimated using surface measured hookload determined when the bit is off bottom.

16. The method of claim **15** wherein the surface measured hookload is determined while the bit is off bottom and has a drillstring rotation, and the bit is sufficiently close to bottom that the drillstring rotation is the same as the expected drillstring rotation in the formation to be drilled.

17. The method of claim **1** in which, during drilling, different equations are employed to determine the downhole weight on bit depending on whether a part of the drillstring in a curved section is in compression or tension.

18. The method of claim **1** further comprising:
calculating hookload by using axial friction coefficient and estimating the weight on the bit;
comparing calculated hookload with measured hookload value; and
if the difference between calculated hookload and measured hookload value is negligible, the estimated downhole weight on the bit is taken as downhole weight on the bit, and if the difference is not negligible, another value will be estimated for downhole weight on the bit and this procedure is repeated to determine the downhole weight on the bit.

19. The method of claim **8** further comprising estimating downhole torque on bit comprising the steps of:
(a) determining the rotational friction force while drilling bit is off bottom;
(b) determining the rotational friction coefficient including axial pipe movement effect from surface torque measurements while bit is off bottom;
(c) determining the effect of downhole weight on the bit on value of rotational friction force during drilling; and
(d) determining downhole bit torque by using rotational friction coefficient and estimated downhole weight.

20. The method of claim **19** in which taking an action comprises determining when to pull the bit off the bottom and pulling the bit off bottom.

21. The method of claim **19** wherein the rotational friction coefficient including the drillstring axial movement effect is estimated while the bit is off bottom and there is no torque at the bit.

22. The method of claim **21** wherein the measured surface torque is measured while the bit is moving downwardly and sufficiently close to bottom that the drillstring rotation at the point of measurement is the same as drillstring rotation in the formation to be drilled.

23. The method of claim **19** in which, during drilling, different equations are employed to determine the downhole torque on bit depending on whether a part of the drillstring in a curved section is in compression or tension.

24. The method of claim **19** wherein rotational friction force while bit is on bottom is estimated by using rotational friction coefficient and downhole weight on the bit.

25. The method of claim **1** used in sliding drilling using a mud driven motor.

26. The method of claim **25** further comprising finding K, where K is the estimated downhole weight on bit divided by pressure differential across the mud driven motor.

27. The method of claim **26** in which K is used to improve drilling performance.

28. Computer readable media containing, in non-transient form, instructions for instructing an autodriller system to carry out the method of claim **1**.

29. A drilling system comprising a rig, a drill string connected downwardly into a borehole, and an autodriller system, the autodriller system being configured to carry out the method of claim **1**.

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