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Modeling of the Effects of Cutting Structure, Impact Arrestor, and Gage Geometry on PDC Bit Steerability

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Abstract

The large number of oil and gas wells drilled directionally with rotary steerable drilling systems requires an understanding of bit directional behaviors. A specific directional drilling application usually raises several questions: Does this bit steer? If not, how should the bit design be changed? What is the maximal dogleg severity (DLS) available for this bit when a drilling system is given?

To answer these questions, polycrystalline diamond compact (PDC) bit steerability was calculated using bit/formation interaction models. These previous models assumed that bit axial and lateral penetrations represented bit tilt motion in directional drilling. Bit steerability was defined as bit side cutting ability divided by bit axial cutting ability. These models overestimated the steerability effects of gage length.

This paper describes a new bit/formation interaction model and its steerability design applications. The model meshes the cutting structure, impact arrestors, gage pads, and formation three dimensionally. It simultaneously uses bit rotation, bit axial penetration, bit tilting motion determined by dogleg severity, and formation properties to simulate the bit/formation interaction. The model predicts the required amount of bit side force, amount of bit walk force created, speed of bit walk in azimuth direction, and variance of bit torque during directional drilling.

In bit steerability design, this model explores the effects of bit geometry parameters on steerability and walk rate, including cutting structure parameters, impact arrestor parameters, active gage geometry, passive gage geometry, and sleeve geometry. The gage and sleeve geometry further includes the number of blades, the length, the width, the spiral, under gauge, and tapered angle. It is found that the gage and the sleeve geometry significantly affect a bit's steerability. In the field, the model is used to select the bit with the desired degree of steerability and walk rate. It is also used to classify bit and gage types based on bit steerability.

Introduction

Bit steerability usually concerns three aspects: bit response to a side force, bit walk direction and walk rate, and bit torque variance.

Millhiem and Warren[1] were the first to realize the importance of bit side cutting characteristics to its drop, build, and turn (walk) abilities. A series of tests were performed to study the relationship between the applied side force and the side cutting ability of roller cone bits and stabilizers. Their study concluded that bits and stabilizers cut laterally and that the bit side cutting ability significantly affects bit drilling direction. Their experimental procedure established a solid foundation in the study of PDC bit steerability many years later.

It has been observed since the early 1980s that PDC bits may walk during directional drilling. Based on his experience and observations of a significant number of PDC bit runs in the Gulf of Thailand, Perry[2] concluded that the profile of PDC bits and bit operational conditions can affect bit drop or build rate and bit walk tendency. Bannerman[3] studied bit walk tendency by collecting field data from 23 wells in the North Sea in which PDC bits with different profiles were used. However, consistent conclusions could not be made because of the complexity of the problem.

Menand, Selami *et al.*[4,5] developed a 3D computer model for the prediction of PDC bit walk angle and steerability. In this model, bit motion was determined by the rotation speed, the axial penetration rate, and the lateral motion. Forces acting on cutters were calculated by estimating the interaction between the cutter and the formation. By applying a predetermined side cutting action with axial penetration and bit rotation, the bit's reaction forces can be calculated. Bit walk angle is then obtained. A test bench was then designed following the same principle developed by Willhiem and Warren[1] to test the PDC bit side cutting ability and bit walk tendency. Based on the results from 3D computer model and from the test bench, simple mathematical formulas for bit walk angle and bit steerability index were derived. Both bit walk angle and bit steerability were expressed as a simple function of inner cone length, outer structure height, average back rake angle of PDC cutters, and the length of active and passive gage.

Barton[6] described an approach of calculating bit side forces arising from the applied bit side penetration. In this approach, the bit was given a prescribed rotation, a prescribed axial penetration, and a prescribed lateral penetration. By incrementing the angular orientation of the bit and simultaneously applying the corresponding increments of axial and lateral penetration, the bit forces in bit axial direction and bit lateral direction can be calculated from bit/formation interaction model. Although Barton did not mention bit walk prediction, the approach that he described could be used for calculating the walk angle.

All of these previous models assumed that bit motion in directional drilling could be represented by bit rotation, bit axial penetration rate, and bit lateral penetration rate. The effects of bit gauge on bit steerability were usually greatly overestimated by previous models.

From deviation mechanisms of the BHA and field observations, Gaynor and Chen[7] concluded that bit tilting contributes more to bit steerability than side cutting. They also concluded that bit side cutting ability is unnecessary for bit steerability if the bit is continuously tilted in the desired direction of travel (with the exception of push-the-bit rotary steerable system).

Mensa-Wilmot[8] qualitatively studied the effects of gage pad geometry on bit steerability without modeling the bit/formation interaction.

To better understand the bit directional behaviors, some basic studies have been performed in this paper. First, these studies mathematically prove that bit lateral penetration rate cannot represent bit tilt motion during directional drilling. Second, a bit may have three basic drilling modes when it is used to drill a directional well. It is found that bit/formation interaction is different in each drilling mode. Based on these two basic understandings, a new computer simulator is developed. Its working principle and its application to bit design are described in detail in the paper.

Bit Side Cutting vs. Bit Tilting

Bit side cutting motion is usually defined as the bit lateral motion perpendicular to bit axis and is measured as rate of lateral penetration (ft/hr). Bit tilt motion, on the other hand, is defined as the rate of angle change of bit axis relative to the instantaneous direction of the wellbore. Fig. 1 depicts the bit side cutting motion and bit tilt motion, respectively. In previous models, bit steerability was defined as the ratio of lateral vs. axial drillability[4,5,6]:

Bs = D_lateral/D_axial .... (1)

In this equation, the lateral drllability (D_lateral) is defined as the rate of lateral penetration vs. the side force. The axial drllability (D_axial) is defined as the rate of axial penetration vs. the weight on bit.

To calculate the steerability, it is necessary to obtain the lateral rate of penetration (ROP). An example was given by Barton[6]: bit rotational speed RPM = 100, axial ROP = 50 ft/hr and DLS = 8.5 deg/100ft. What is the equivalent lateral ROP to attain a build rate of 8.5 deg/100 ft?

Method 1: assuming drilling time is two hours.

T = 2 hrs; L = 100ft; β = 8.5 deg; lateral movement = L*sin(β) = 14.78 ft; Lateral ROP = 7.39 ft/hr.

Method 2: assuming drilling time is one hour:

T = 1 hrs; L = 50ft; β = 4.25 deg; lateral movement = L*sin(β) = 3.7 ft; Lateral ROP = 3.7 ft/hr.

Method 3: assuming drilling time is one bit revolution

T = 1/100/60 hrs; L = 0.0083ft; β = 7.055e-4 deg; lateral movement = L*sin(β) = 1.026e-7 ft; Lateral ROP = 6.1566e-4 ft/hr.

We calculated three different lateral ROPs. Which one is correct? Barton[6] used lateral ROP = 7.5 ft/hr (from method 1) to calculate bit steerability, while Menand *et al.*[4,5] used lateral penetration in one bit revolution to calculate steerability.

From this example, we see that bit DLS is not equivalent to bit lateral ROP. Therefore, the calculation of bit steerability using equation (1) may be incorrect.

It is obvious that the interaction between the bit and the formation arising from bit side cutting motion is significantly different from that arising from bit tilt motion. Fig. 2 shows that bit/formation interaction arising from bit tilt motion also depends on the point around which the bit is tilted.

In summary, bit tilt motion cannot be simplified or represented by bit side cutting motion. The calculation of bit steerability must directly consider bit tilt motion.

Bit Kinematics in Directional Well

Fig. 3 shows a typical directional well with S-shape. The well can be divided into five sections: vertical section A, build section B, tangent section C, drop section D, and tangent section E. Within sections A, C, and E, straight holes are drilled and bit DLS is equal to zero. Within sections B and D, the bit follows a perfect circular path and the corresponding DLS is a non-zero constant. There are transitions between any two of the sections. These transitions may be called kickoff sections in which bit DLS changes with drilling time.

Bit motion in a directional well can be generally classified into three basic modes based on the DLS:

1. Straight hole drilling: DLS = 0
2. Build/drop drilling: DLS = constant
3. Kick off drilling: DLS ~= constant

Fig. 4 shows that bit kinematics in straight hole drilling can be fully determined by two parameters: RPM and ROP. In this case, only the bit face cutting structure interacts with the formation. The bit does not have any side cutting action. It is noted that bit motion is not dependent on the configuration of BHA system.

Fig. 5 shows the bit motion in drilling the build section. Because the bit follows a perfect circular path and the radius of the path is a function of DLS, the bit kinematics is fully determined by three parameters: RPM, ROP, and DLS. In this case, the bit face cutting structure interacts with the hole bottom. The bit gage and/or the sleeve may interact with the hole wall, depending on the length of the gage or the sleeve and the magnitude of DLS. However, the bit, including the bit gage, has only a little side cutting action because the radius of the path is constant. It is also noted that bit motion is not dependent on the configuration of BHA system.

Bit kinematics in a kick off operation is more complicated than the above two cases and is described in detail in next section.

Bit Kinematics in Kick Off Operation

One of the characteristics of the kick off operation is that the DLS changes with time. Consequently, the bit path depends on the steering mechanism of a drilling system.

Fig. 6 shows a conventional steerable drilling system with a bent-housing motor. To fully describe the bit motion, at least four parameters are required: RPM, ROP, tilt length (L), and tilt rate (TR). The TR may be expressed as a function of DLS and ROP as follows:

$$TR = DLS \times ROP / 100 \quad (deg/hr) \qquad (2)$$

Therefore, four parameters, RPM, ROP, DLS, and L, are required to determine the bit motion when a conventional steerable drilling system is used.

Fig. 7 shows the steering mechanism of a typical point-the-bit RSS drilling system. The eccentric ring creates a deflection which causes the bit to tilt in the opposite direction around the focal bearing. Similar to Fig. 6, the bit motion can also be described by four parameters: RPM, ROP, DLS, and L when a point-the-bit drilling system is used.

Fig. 8 shows the steering mechanism of a push-the-bit rotary steerable drilling system. A hydraulic side force pushes the pad against the wall and drives the bit in the opposite direction. The effectiveness of such a steering mechanism depends on the magnitude of the side force and the stiffness of the hole wall. As shown in Fig. 8, the side force may not create a pure side cutting action of the bit because of the stiffness of the BHA. The bit and part of the BHA may tilt around some point far from the bit face. The tilt length, L, depends on the configuration of the BHA and the locations of the stabilizers. Therefore, four parameters, RPM, ROP, DLS, and L, are also required to determine the bit motion when a push-the-bit drilling system is used. However, the tilt length is usually much longer in a push-the-bit system than in a point-the-bit system.

In summary, bit kinematics in kick off operations, regardless of the steering mechanism, can be fully described by four parameters: RPM, ROP, DLS, and L. Fig. 9 depicts how bit motion can be modeled in three dimensional coordinates.

Bit/Formation Interaction Model

To simulate the interaction between the bit and the formation in directional drilling, two 3D spherical coordinate systems are used: bit coordinate system and hole coordinate system. In the beginning, both bit and hole coordinate systems have the same origin and orientation. The bit coordinate system is fixed with the bit and rotates with the bit. The hole coordinate system is fixed with the formation (fixed in the space). First, the bit body, including face cutters, gage cutters, impact arrestors (if any), active and passive gages, and sleeve pad, is meshed into cutlets (small 3D elements) in the bit coordinate system. The geometry of the gage pad, including the length, the width, under-gage, tapered gage, spiral angle, is considered. Fig. 10 provides an example of a PDC bit after meshing. Second, the hole, including the bottom and wall, is meshed in the hole coordinate system. Fig. 11 shows an example of the meshed hole. The initial pattern of the hole bottom is obtained by rotating the bit a full revolution without penetration. The following steps are used in the determination of the cutting depth of a cutlet during a time interval from t to $t + \Delta t$.

(a) Calculate the new position of the cutlet, ($\varphi(i+1)$, $\theta(i+1)$, $\rho(i+1)$), arising from three movements during time interval Δt: tilting relative to bit axis at time t, penetration along bit axis, rotation around bit axis.

(b) Determine the element location of hole associated with this cutlet, ($\varphi(i+1)$, $\theta(i+1)$, ρh).

(c) Calculate penetration depth of the cutlet $d\rho = \rho(i+1) - \rho h$

(d) Update the hole coordinate by replacing ρh with $\rho(i+1)$.

After the cutting depth is determined, the cutting area and cutting volume can be easily calculated for a cutlet and for a cutter. The forces acting on each cutter, active gage pad, and/or passive gage pad can be calculated by force models described below.

Cutter Force Model and Gage Force Model

Cutter Force Model

Several cutter force models are available in the industry. Models developed by Glowka[9] and Warren[10] are often used. These models may be applied to face cutters, gage cutters, and impact arrestors (if any).

Active Gage Force Model

The active gage pad may be able to cut into the wall but has less cutting capability than the gage cutters. Fig. 12a shows the active gage force model. There are three forces acting on the active gage pad: axial force, tangent force and normal force. For each cutlet on the active gage, these forces may be modeled as:

$$F_n = ka_1 * \Delta 1 + ka_2 * \Delta 2$$
$$F_a = ka_3 * F_n \quad \text{.......} (3)$$
$$F_t = ka_4 * F_n$$

Where Δ1 is the cutting depth of a respective cutlet (gage element) extending into adjacent portions of a wellbore, and Δ2 is the deformation depth of hole wall by a respective cutlet. The other coefficients ka_1, ka_2, ka_3, and ka_4 can be determined by tests.

Passive Gage Force Model

The passive gage pad does not have any cutting capability but may deform the hole wall. Fig. 12b shows the passive gage force model. There are three forces acting on the passive gage pad: axial force, tangent force and normal force. For each cutlet on the passive gage, these forces may be modeled as:

$$F_n = kp_1 * \Delta p$$
$$F_a = kp_2 * F_n \quad \text{.......} (4)$$
$$F_t = kp_3 * F_n$$

Where Δp is depth of deformation of formation material by a respective cutlet of adjacent portions of the wellbore. The other coefficients kp_1, kp_2 and kp_3 can be determined by tests.

Calculation of Bit Steerability

Fig. 13 shows the forces acting on a bit in directional drilling. To steer the bit in plane A, a steer force, Fs, is applied in plane A by the steering mechanism. However, because of the cutter's arrangement and formation characteristics, the bit may turn toward plane B (walk left) or plane C (walk right). Fw is the walk force.

Bit Steerability

Bit steerability may be defined as how easy a bit will steer (tilt) when a side force or a side moment is applied to the bit. In this paper, the bit steerability is defined as follows:

BS = Fs/DLS .... (5)

In this equation, Fs is the required steer force or side force which must be applied to the bit to steer the bit with expected DLS.

Bit Walk

Walk angle as defined in Fig. 14 may be used to describe bit walk tendency. After the walk force, Fw, is calculated from the model, bit walk rate may be calculated as follows:

Walk Rate = DLS* Fw/Fs .... (6)

Where Walk Rate being measured in deg/100 ft.

Bit Face Control

During directional drilling, the forces acting on a bit varies usually with time. As a result, the bit torque may vary significantly, which makes tool face control difficult. The average torque and torque range are used to describe the degree of difficulty of face control of a bit .

Model Applications to Bit Steerability Design

A 6 ¾-in. PDC bit with longer gage is analyzed. Its meshed cutting edge, as well as the gage and sleeve, is shown in Fig. 15. The gage has six blades; each blade is 2 in. long and 1 in. wide. The sleeve has four blades; each blade is 2 in. long and 1.5 in. wide. Both gage pad and sleeve are fully in gauge.

The following operational parameters are used as input:

RPM = 120; ROP = 30 ft/hr; DLS = 10 deg/100ft; Tilt length = 3 ft; Rock strength = 18000 psi; Two drilling modes are simulated: Kickoff operation and build operation.

Bit Steerability in Kickoff Operation

Fig. 16 shows the steer force or side force required to steer the bit with DLS = 10 deg/100ft under the given operation conditions. Approximately 3,324 lb side force is required, indicating that the bit is difficult to steer. Table 1 specifies the side force required to steer each part. It is very easy to steer the cutting structure because it consumes less than 1% of the required side force. It is very difficult to steer the gage pad and the sleeve. To increase the steerability of the bit in a kick off operation, reduce the length of the sleeve or use under-gauged sleeve or tapered sleeve.

Bit Walk in Kickoff Operation

Fig. 17-19 shows the bit walk tendency, bit walk rate, and amount of walk force created under the given operation conditions. The bit as a whole walks left with a walk angle -8.5 deg, a walk rate -1.49 deg/100ft, and a walk force -497 lbs. Table 2 lists the contribution of each part to the walk force. The sleeve contributes the most of the walk force.

Bit Steerability in Build Operation

The same bit is now used for drilling into a build section, in which the bit follows a perfect circular path, as shown in Fig. 5. The radius of this circular path is fully determined by DLS (10 deg/100 ft). Table 3 lists the side force required to steer the bit. In a comparison of Table 1 and Table 3, it is found that the side force required to steer the bit in a build section is approximately only 1.3% of that required in a kick off section. However, the cutting structure plays a greater role in a build operation than in a kick off operation. This example indicates that, in build or drop operations, bit steerability is not any more of a concern. More attention should be paid to improving bit stability and bit drillability.

Bit Walk in Build Operation

Fig. 20 shows that the bit walks to the left when drilling into the build section, with an average walk angle of -10.5 deg. Fig. 21 shows the walk force with an average of -15.4 lb. The bit walk force in drilling a build section is much less than that in drilling a kickoff section.

Conclusions

- Bit/formation interaction induced by bit tilt motion is totally different from that induced by bit side cutting motion. This is especially true for a bit with longer gage and longer sleeve. It is necessary to consider bit tilt motion in the evaluation of bit directional behaviors.
- In drilling a directional well, there are three basic drilling modes, namely, straight section (DLS = 0), build/drop section (DLS = constant) and kick off section (DLS varies). The bit behaves differently in each of these drilling modes.
- Kick off operations require a large side force to steer the bit to an expected DLS. In this operation, the cutting structure (face cutters) plays a small role in the determination of bit steerability and bit walk force. The gage pad and/or the sleeve govern the steerability and bit walk force. More attention should be paid to gage/sleeve design when the bit is used in kick off or side track operations.
- Drilling into a build or drop section in which DLS is a constant requires much less side force to steer the bit. It is true even for a bit having a longer gage and a longer sleeve. There is almost no side cutting action for a bit drilling into this section, especially in long radius drilling. In this operation, bit stability and bit drillabilty become more important than bit steerability. Therefore, more attention should be paid to cutting structure design.

Acknowledgments

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Nomenclature

BHA = *Bottomhole assembly*
DLS = *Dogleg severity (deg/100 ft)*
RSS = *Rotary steerable system*
RPM = *Rotation per minute*
ROP = *Rate of penetration*
WOB = *Weight on bit*
TR = *Tilt rate (deg/hr)*
PDC = *Polycrystalline diamond compact*

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Table 1: Side force required to steer each part and the bit in kickoff operation

	All PDC Cutters	Gage Pad	Sleeve	Entire Bit
Side Force Required (lb)	30.95	1653.2	1639.9	3324.1
Contribution (%)	0.93	49.73	49.33	100.0

Table 2: Walk force generated by each part and the bit in kickoff operation

	All PDC Cutters	Gage Pad	Sleeve	Entire Bit
Walk Force Generated (lb)	-32.39	-232.6	-232	-497
Contribution (%)	6.52	46.8	46.7	100

Table 3: Side force required to steer each part and the bit in build operation

	All Cutters	Gage Pad	Sleeve	Entire Bit
Side Force Required (lbs)	11.53	16.97	14.38	42.88
Contribution (%)	26.89	39.58	33.54	100

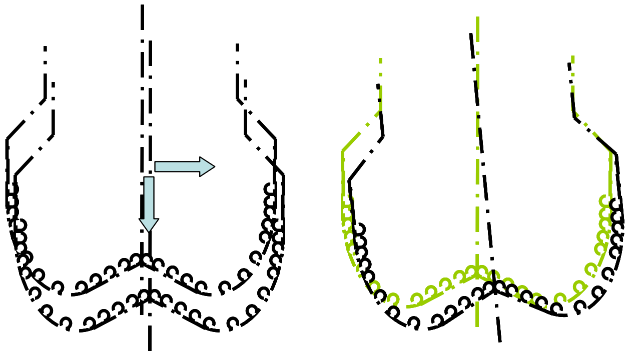

Fig. 1: Bit side cutting and bit tilt

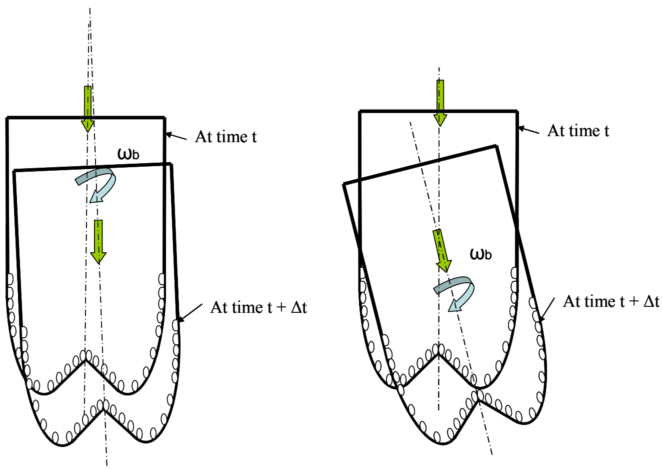

Fig. 2: Bit/formation interaction caused by bit tilt

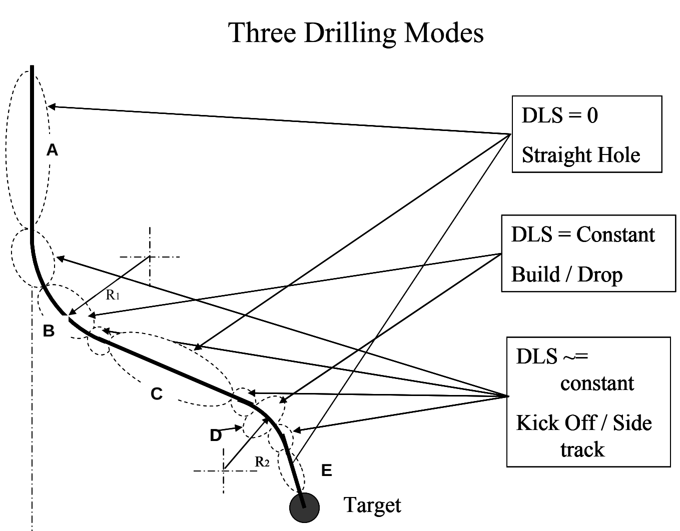

Fig. 3: Bit motion in a directional well and three basic drilling modes

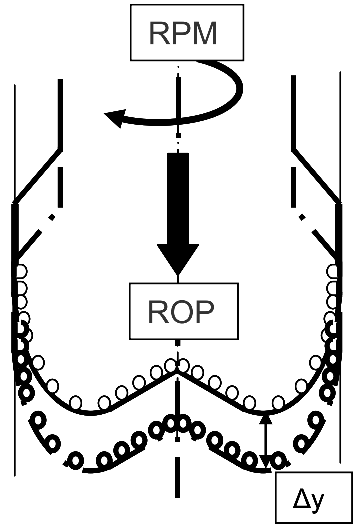

Fig. 4: Bit kinematics in straight hole drilling where DLS is zero

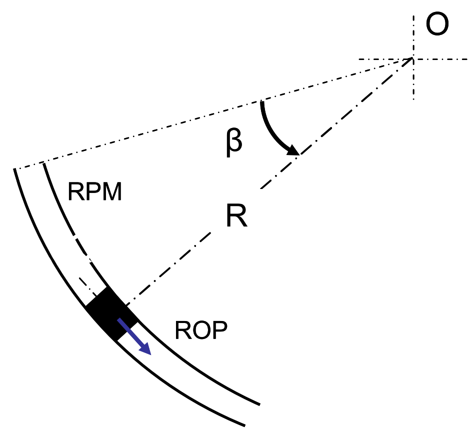

Fig. 5: Bit kinematics in build section drilling where DLS is constant

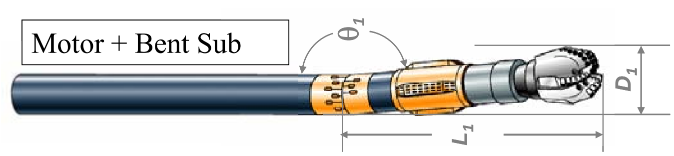

Fig. 6: A conventional steerable drilling system with down hole motor and bent sub

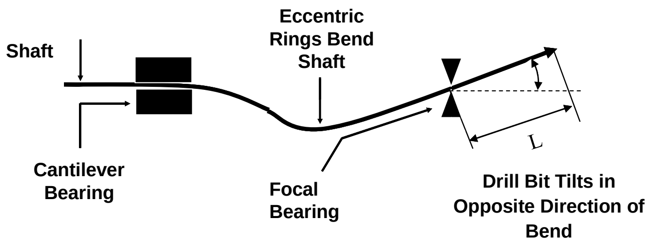

Fig. 7: Steering mechanism of a typical point-the-bit RSS

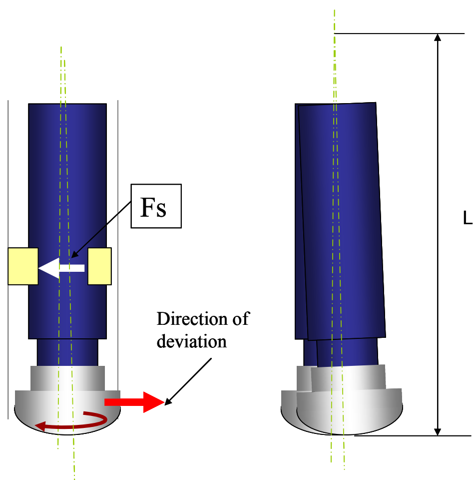

Fig. 8: Push-the-bit RSS and steering mechanism

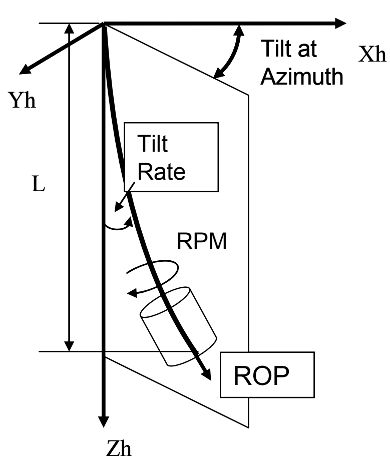

Fig. 9: Model of bit kinematics in kick off operation where DLS changes with time

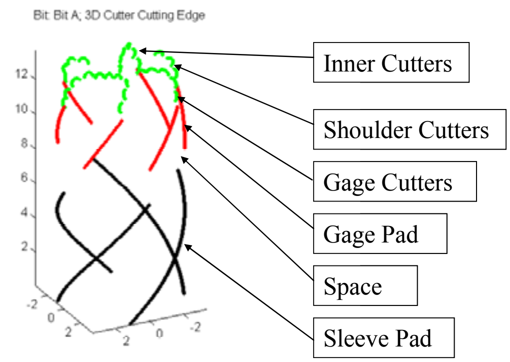

Fig. 10: A meshed PDC bit including cutting structure, gage pad and sleeve

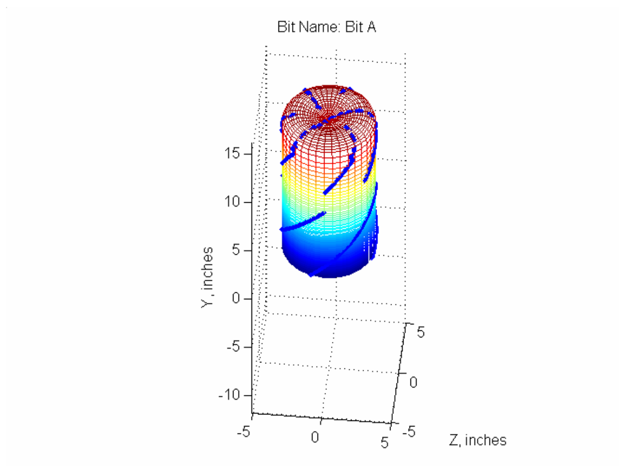

Fig. 11: A meshed bit in a meshed hole

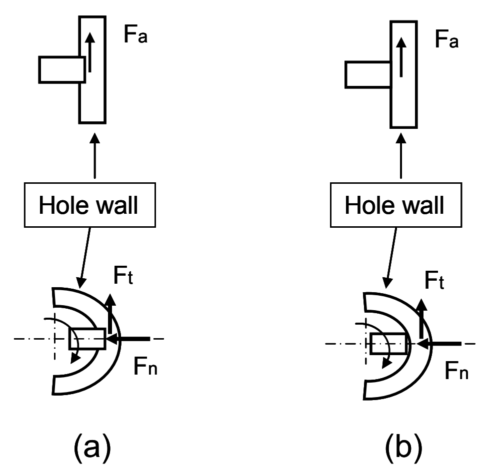

Fig. 12: Active gage force model (left) and passive gage force model (right)

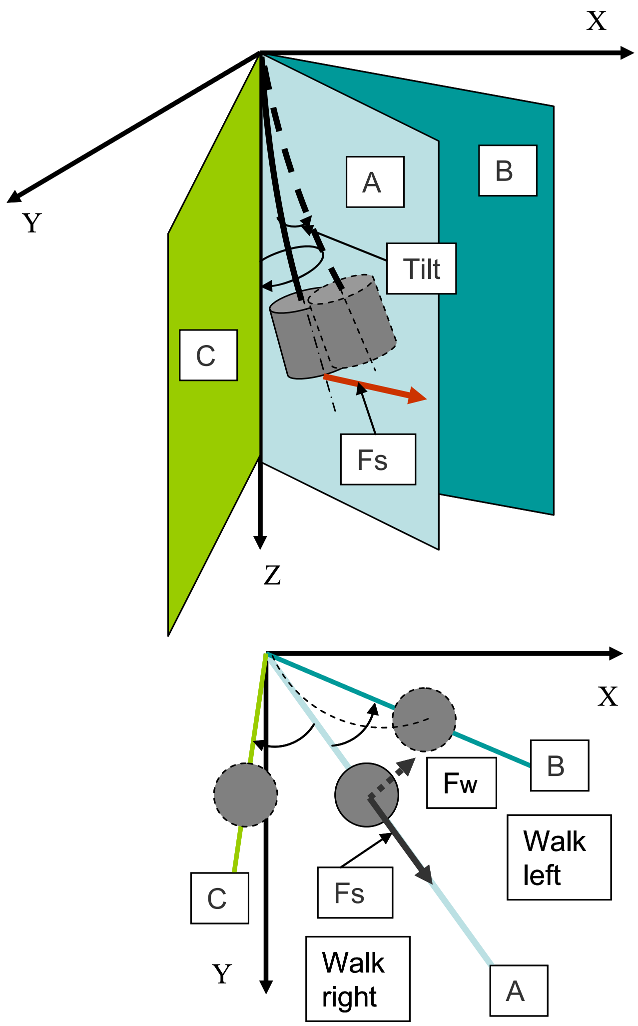

Fig. 13: Steer forces and walk force of a bit in directional drilling

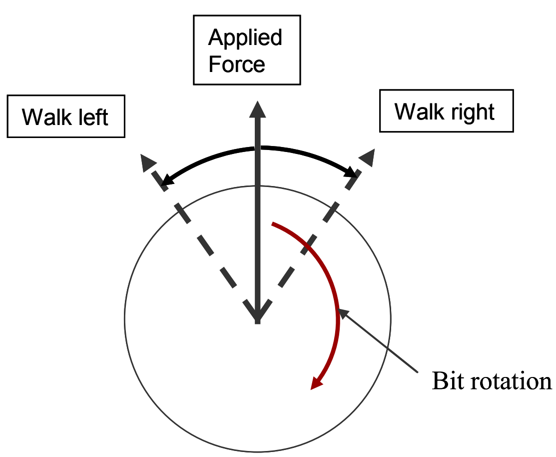

Fig. 14: Definition of walk left and walk right

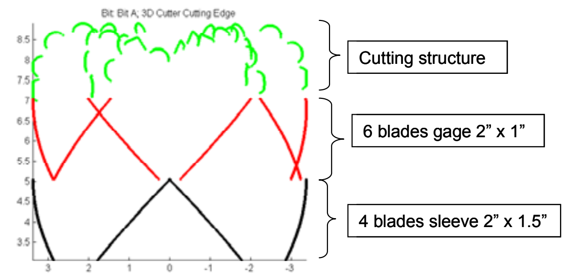

Fig. 15: A 6 ¾" PDC bit with 2" gage and 2" sleeve

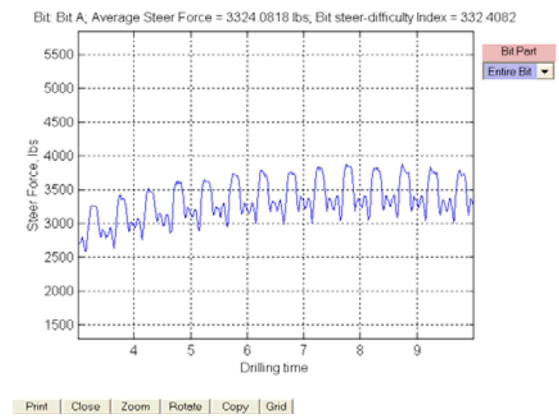

Fig. 16: Steer force required to kick off the bit to reach DLS = 10 deg/100ft

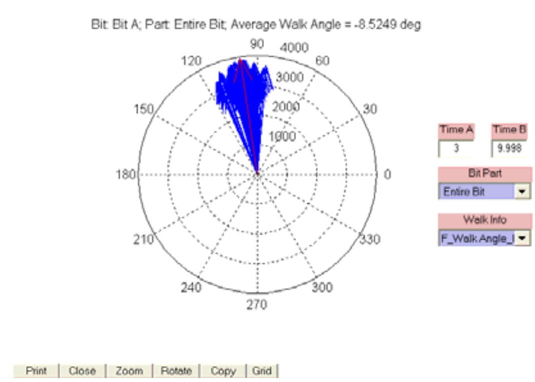

Fig. 17: Calculated bit walk angle in kickoff operation showing the bit walk left

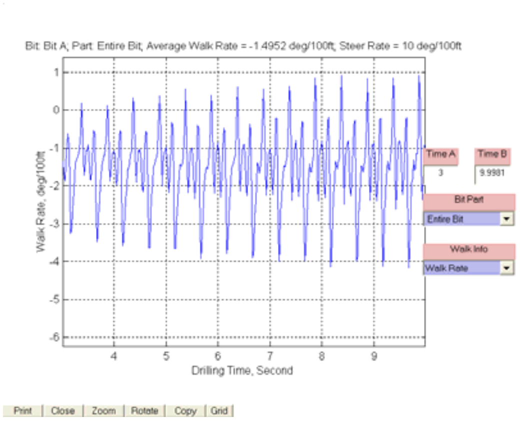

Fig. 18: Calculated bit walk rate in kickoff operation

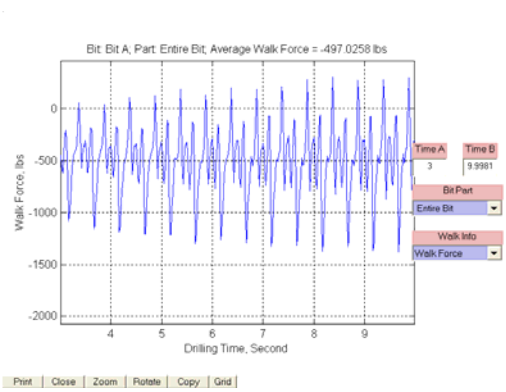

Fig. 19: Calculated bit walk force in kickoff operation

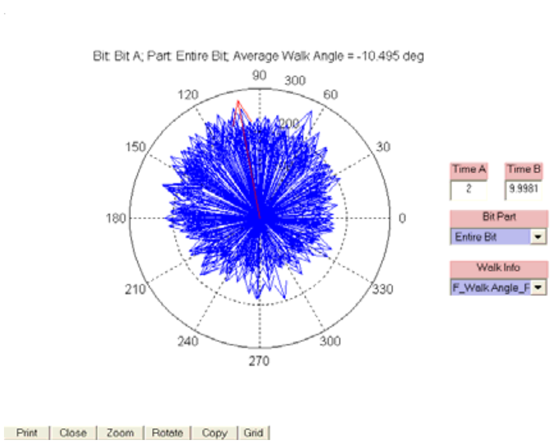

Fig. 20: Calculated bit walk angle in build section showing the bit walk left and right with average walk left

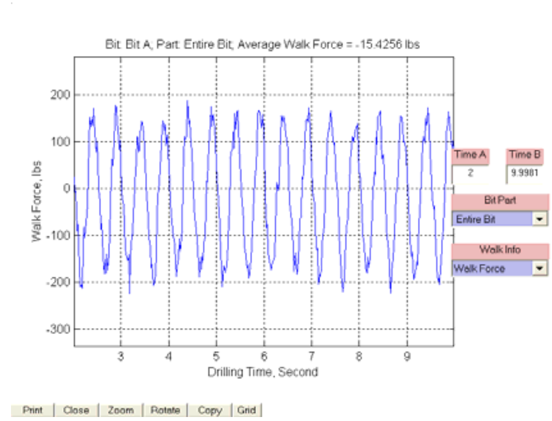

Fig. 21: Average walk force in build section