

Anti-Whirl Drill Bits, Wellsite Systems, and Methods of Using the Same

FIELD OF THE INVENTION

The present invention relates to systems and methods for preventing whirl and other deviations of the drill bit and/or bottom-hole assembly while drilling within a wellbore.

BACKGROUND OF THE INVENTION

Drill bit whirl and deviations are a significant problem within the drilling industry. Oil, gas, water, and other natural resources are often located between 4,000 and 10,000 feet below ground. As a result, even a one-degree deviation of an well can result in a significant increase in drilling distance, time and cost.

In some application, the driller seeks a vertical wellbore. A smooth vertical wellbore facilitates running larger casing with minimal clearance and affords the possibility of using an extra string of casing at some later state in well construction operations. A wellbore that drifts away from and back into verticality can eliminate this option. Additionally, if multiple wellbore are drilled from a single platform, deviations can cause drill string collisions.

Even in controlled steering or directional drilling applications, it may be highly desirable to maintain the desired trajectory, for example when drilling to targets below faulted rocks, in steeply dipping beds, or in tectonically active areas.

Additionally, drill bit whirl, a condition wherein the bit's center of rotation shifts away from its geometric center, leads to several problems. These problems include non-cylindrical holes, wellbore deviation, and excessive bit wear.

Conventional anti-whirl drill bits attempt to reduce whirl by creating an imbalanced side force by cutter(s)-rock interaction. This imbalance force will only have a predictable magnitude and direction if the cutting action is smooth and continuous and the cutters are not worn or damaged. Neither of these conditions occur regularly as cutting action is often a discrete process rather than a

continuous one (as when the cutters generate chips rather than continuous cuttings). When the rock is removed by a chipping action, the magnitude and direction is neither constant nor predictable.

Accordingly, there is a continued need for apparatus and methodology for preventing whirl and deviations.

DESCRIPTION OF THE DRAWINGS

For a fuller understanding of the nature and desired objects of the present invention, reference is made to the following detailed description taken in conjunction with the accompanying drawing figures wherein like reference characters denote corresponding parts throughout the several views and wherein:

FIG. 1 illustrates a wellsite system in which the present invention can be employed.

FIG. 2 illustrates a drill bit according to the present inventions.

FIG. 2A illustrates a drill bit according to the present inventions within a borehole.

FIG. 3A illustrates a cross-section of a drill bit centered within a borehole.

FIG. 3B illustrates a cross-section of a drill bit located off-center within a borehole.

DETAILED DESCRIPTION OF THE INVENTION

The present invention provides apparatus and methods for preventing whirl and other deviations of the drill bit and/or bottom-hole assembly while drilling within a wellbore.

The inventions provide herein are adapted for use in a range of drilling operations such as oil, gas, and water drilling. As such, the bit body is designed for incorporation in wellsite systems that are commonly used in the oil, gas, and water industries. An exemplary wellsite system is depicted in FIG. 1.

FIG. 1 illustrates a wellsite system in which the present invention can be employed. The wellsite can be onshore or offshore. In this exemplary system, a

borehole 11 is formed in subsurface formations by rotary drilling in a manner that is well known. Embodiments of the invention can also use directional drilling, as will be described hereinafter.

A drill string 12 is suspended within the borehole 11 and has a bottom hole assembly 100 which includes a drill bit 105 at its lower end. The surface system includes platform and derrick assembly 10 positioned over the borehole 11, the assembly 10 including a rotary table 16, kelly 17, hook 18 and rotary swivel 19. The drill string 12 is rotated by the rotary table 16, energized by means not shown, which engages the kelly 17 at the upper end of the drill string. The drill string 12 is suspended from a hook 18, attached to a traveling block (also not shown), through the kelly 17 and a rotary swivel 19 which permits rotation of the drill string relative to the hook. As is well known, a top drive system could alternatively be used.

In the example of this embodiment, the surface system further includes drilling fluid or mud 26 stored in a pit 27 formed at the well site. A pump 29 delivers the drilling fluid 26 to the interior of the drill string 12 via a port in the swivel 19, causing the drilling fluid to flow downwardly through the drill string 12 as indicated by the directional arrow 8. The drilling fluid exits the drill string 12 via ports in the drill bit 105, and then circulates upwardly through the annulus region between the outside of the drill string and the wall of the borehole, as indicated by the directional arrows 9. In this well known manner, the drilling fluid lubricates the drill bit 105 and carries formation cuttings up to the surface as it is returned to the pit 27 for recirculation.

The bottom hole assembly 100 of the illustrated embodiment includes a logging-while-drilling (LWD) module 120, a measuring-while-drilling (MWD) module 130, a roto-steerable system and motor, and drill bit 105.

The LWD module 120 is housed in a special type of drill collar, as is known in the art, and can contain one or a plurality of known types of logging tools. It will also be understood that more than one LWD and/or MWD module can be employed, e.g. as represented at 120A. (References, throughout, to a module at the position of 120 can alternatively mean a module at the position of

120A as well.) The LWD module includes capabilities for measuring, processing, and storing information, as well as for communicating with the surface equipment. In the present embodiment, the LWD module includes a pressure measuring device.

The MWD module 130 is also housed in a special type of drill collar, as is known in the art, and can contain one or more devices for measuring characteristics of the drill string and drill bit. The MWD tool further includes an apparatus (not shown) for generating electrical power to the downhole system. This may typically include a mud turbine generator powered by the flow of the drilling fluid, it being understood that other power and/or battery systems may be employed. In the present embodiment, the MWD module includes one or more of the following types of measuring devices: a weight-on-bit measuring device, a torque measuring device, a vibration measuring device, a shock measuring device, a stick slip measuring device, a direction measuring device, and an inclination measuring device.

A particularly advantageous use of the system hereof is in conjunction with controlled steering or "directional drilling." In this embodiment, a roto-steerable subsystem 150 (FIG. 1) is provided. Directional drilling is the intentional deviation of the wellbore from the path it would naturally take. In other words, directional drilling is the steering of the drill string so that it travels in a desired direction.

Directional drilling is, for example, advantageous in offshore drilling because it enables many wells to be drilled from a single platform. Directional drilling also enables horizontal drilling through a reservoir. Horizontal drilling enables a longer length of the wellbore to traverse the reservoir, which increases the production rate from the well.

A directional drilling system may also be used in vertical drilling operation as well. Often the drill bit will veer off of a planned drilling trajectory because of the unpredictable nature of the formations being penetrated or the varying forces that the drill bit experiences. When such a deviation occurs, a directional drilling system may be used to put the drill bit back on course.

A known method of directional drilling includes the use of a rotary steerable system ("RSS"). In an RSS, the drill string is rotated from the surface, and downhole devices cause the drill bit to drill in the desired direction. Rotating the drill string greatly reduces the occurrences of the drill string getting hung up or stuck during drilling. Rotary steerable drilling systems for drilling deviated boreholes into the earth may be generally classified as either "point-the-bit" systems or "push-the-bit" systems.

In the point-the-bit system, the axis of rotation of the drill bit is deviated from the local axis of the bottom hole assembly in the general direction of the new hole. The hole is propagated in accordance with the customary three point geometry defined by upper and lower stabilizer touch points and the drill bit. The angle of deviation of the drill bit axis coupled with a finite distance between the drill bit and lower stabilizer results in the non-collinear condition required for a curve to be generated. There are many ways in which this may be achieved including a fixed bend at a point in the bottom hole assembly close to the lower stabilizer or a flexure of the drill bit drive shaft distributed between the upper and lower stabilizer. In its idealized form, the drill bit is not required to cut sideways because the bit axis is continually rotated in the direction of the curved hole. Examples of point-the-bit type rotary steerable systems, and how they operate are described in U.S. Patent Application Publication Nos. 2002/0011359; 2001/0052428 and U.S. Patent Nos. 6,394,193; 6,364,034; 6,244,361; 6,158,529; 6,092,610; and 5,113,953 all herein incorporated by reference.

In the push-the-bit rotary steerable system there is usually no specially identified mechanism to deviate the bit axis from the local bottom hole assembly axis; instead, the requisite non-collinear condition is achieved by causing either or both of the upper or lower stabilizers to apply an eccentric force or displacement in a direction that is preferentially orientated with respect to the direction of hole propagation. Again, there are many ways in which this may be achieved, including non-rotating (with respect to the hole) eccentric stabilizers (displacement based approaches) and eccentric actuators that apply force to the drill bit in the desired steering direction. Again, steering is achieved by creating

non co-linearity between the drill bit and at least two other touch points. In its idealized form the drill bit is required to cut side ways in order to generate a curved hole. Examples of push-the-bit type rotary steerable systems, and how they operate are described in U.S. Patent Nos. 5,265,682; 5,553,678; 5,803,185; 6,089,332; 5,695,015; 5,685,379; 5,706,905; 5,553,679; 5,673,763; 5,520,255; 5,603,385; 5,582,259; 5,778,992; 5,971,085 all herein incorporated by reference.

Particular embodiments of the inventions described herein provide drill bits 105 and bottom-hole assemblies 100 for reducing whirl and/or deviations.

Anti-Whirl Bits

FIG. 2 depicts a drill bit 105. Drill bit 105 includes a trailing end 202 and a cutting portion 204. Trailing end 202 is adapted for direct or indirect connection with drill string 12. Cutting portion 204 includes one or more ribs 206a, 206b, 206c, 206d. Ribs 206 include gauge sections 208, which contact the walls of the borehole that has been drilled by cutters 210. Although cutters 210 are only depicted on rib 206b, cutters 210 can be configured on a plurality or all of ribs 206 as advantageous for particular drilling situations.

In embodiments of the present invention, one or more orifices 212 are located on the exterior of drill bit 105. Orifices 212 can be located on gauge sections 208 or in valleys 214 between ribs 206. The orifices 212 allow fluid 26 from the interior of drill string 12 to exit the drill bit to achieve stability and reduce whirl. Additional orifices can be located on drill bit 105, for example, on the leading end 216 for lubrication and removal of cuttings as is known in the art.

In some embodiments, drill bit 105 contains a single orifice 212. Drill fluid 26 flows from orifice 212, and contacts the wall of borehole 11, creating a side force substantially perpendicular to the orientation of orifice 212 and gauge section 208. This force, creates an anti-whirl effect.

In some embodiments, the orifice 212 is positioned substantially opposite from the majority of cutters 210. For example, if the cutters 210 are located longitudinally along the drill bit 105, the orifice 212 can be located about 180° from the cutters 210. In such an embodiment, drill fluid released from the orifice 212 creates a side force that pushes the bit in the direction of the cutters 210.

This embodiment (1) causes in increased contact between cutters 210 and the wall of borehole 11, and/or (2) neutralizes side forces resulting from contact between the cutters 210 and the borehole wall.

In other embodiments, the orifice 212 is positioned approximately 90° behind the majority of the cutters 210. As illustration of this principle, consider the situation depicted in FIG. 2A. Drill bit 105 is rotating counter-clockwise in borehole 11. Cutters 210 are about to impact a protuberance 218 from borehole wall 220. If protuberance 218 is particularly strong material, protuberance will remain intact at least momentarily when first contacted by cutters 210. The rotational force on drill bit 105 will cause drill bit 105 to move in the negative y direction until gauge pad 206a contacts borehole wall 220. However, if orifice 212 is located on gauge pad 206a, the drilling fluid 26 will generate a force in the positive y direction, counteracting the tendency of the drill bit 105 to move off center. Moreover, the positive y force moves the entire bit 105, thereby providing additional force to cutters 210 and assisting in borehole propagation.

Other cutter 210 and orifice 212 configurations are within the scope of these inventions. For example, the aggregate force vector generated by the rotation of the drill bit 105 and contact with a plurality of cutters 210 can be calculated using known equations and technology. The orifice 212 can be configured to counteract the most probable force vectors.

By utilizing the hydraulic force of drilling fluid 26 from orifice 212, drill bits 105 produce a more predictable and constant imbalance force to reduce and/or prevent bit whirl. The direction of the imbalance force is known given the position of the port. The magnitude of the imbalance force is a function of the distance between the orifice 212 and borehole wall 220, the differential pressure between the drilling fluid 26 in the borehole and the drilling fluid 26 in the drill string 12, and the geometry (e.g. shape and size) of the orifice 212. Furthermore, wear and damage to the cutters 210 should not affect the amplitude and direction of the side force.

In some embodiments, the exterior of orifice 212 is surrounding by a raised annulus or other geometric feature in order to form greater hydraulic

pressure as drilling fluid 26 exits orifice 212. Such a feature and/or the entire gauge section 206 can be coated with or fabricated entirely from a wear resistant or hardfaced material such as polycrystalline diamond (PCD).

Self-Stabilized Bits and Bottom Hole Assemblies

Another embodiment of the invention utilizes one or more orifices 212 to stabilize a drill bit 105 and/or bottom hole assembly (BHA) within a borehole.

FIG. 3A depicts a cross-section of a drill bit 105 with three gauge pads 206a, 206b, 206c generally spaced (e.g. 120° on center) around the circumference of the drill bit 105, each having an orifice 212a, 212b, 212c, respectively. Drilling fluid 26 (represented by the thick lines) flows from inside the drill bit 105 through orifices 212a, 212b, 212c.

The drill bit 105 depicted in FIG. 3A is generally centered within borehole 11. Accordingly, any hydraulic forces created by the drilling fluid will cancel each other. However, if drill bit 105 moves off center as depicted in FIG. 3B, the amplitude of the force vector generated by drilling fluid 26 from orifice 212a will increase as the space between orifice 212a and borehole wall 220 decrease. Concurrently, any force vector generated by orifices 212b and 212c will decrease, resulting in a net force vector (represented by arrow 222) pushing the bit away from the wall 220.

In some embodiments, fluid flow to the one or more orifices is limited by one or more valve (e.g. choke valves). A single valve may be connected to each orifice by tubing or other means. More preferably, each orifice is independently regulated by a separate valve. Independent regulation ensures that the volume of drilling fluid 26 flowing to a particular orifice 212 does not increase beyond a desired threshold so as to deprive other orifices 212 or other ports (e.g. ports located on the leading edge 216 of drill bit 105).

While the embodiment in FIGS. 3A and 3B depicts a drill bit 105 with three orifices 212, the inventions described herein encompass the use of fluid with any number of orifices 212 for the stabilization of a drill bit 105 or bottom hole assembly. For example, a drill bit 105 with a single orifice would produce a similar effect as a drill bit 105 with three orifices. As the drill bit 105 rotated, the

force generated by the single orifice would increase in amplitude as the orifice passed through regions in which the drill bit 105 was closer to the borehole wall 220. This increased force would urge the drill bit 105 back center. Furthermore, drill bits and bottom hole assemblies having two, three, four, five, or six orifices, and the like are within the scope of the invention.

The principles described herein can be applied to stabilization pads located along the exterior of bottom hole assembly 100 and other portions of the drill string 12. Stabilization pads act similarly to gauge pads to minimize movement of the bottom hole assembly and drill string. In such an embodiment, one or more orifices are added to one or more stabilization pads to allow drilling fluid 26 to act as described herein.

Combination Anti-Whirl and Self-Stabilized Bits

The principles of anti-whirl and self-stabilized bits described herein can be combined to produce a bit 105 that produces net imbalanced side force to reduce whirl while still providing one or more orifices to correct a drift from center of the borehole 11. In such an embodiment, one of a plurality of orifices 212 is larger in cross-sectional area to produce an imbalance side force.

The foregoing specification and the drawings forming part hereof are illustrative in nature and demonstrate certain preferred embodiments of the invention. It should be recognized and understood, however, that the description is not to be construed as limiting of the invention because many changes, modifications and variations may be made therein by those of skill in the art without departing from the essential scope, spirit or intention of the invention.

CLAIMS

Anti-Whirl Bits

1. A drill bit comprising:
an interior cavity in fluid communication with a drill string; and
a first gauge pad located on the exterior of the drill bit, the first gauge pad having a first orifice in fluid communication with the interior cavity, wherein the drill bit is configured such that a fluid continuously flows from the first orifice.
2. The drill bit of claim 1, wherein the fluid flow is sufficient to urge the drill bit away from a wall of a borehole.
3. The drill bit of claim 1, wherein the drill bit further comprises one or more cutters.
4. The drill bit of claim 3, wherein the first gauge pad is located substantially opposite from a majority of the cutters.
5. The drill bit of claim 3, wherein the first gauge pad is located about 90° behind a majority of the cutters, with respect to a direction of rotation of the drill bit.
6. The drill bit of claim 1, further comprising:
a first valve for regulating the flow of fluid from the first orifice.
7. The drill bit of claim 1, further comprising:
a second gauge pad located on the exterior of the drill bit, the second gauge pad having a second orifice in fluid communication with the interior cavity.
8. The drill bit of claim 7, wherein the first valve regulates the flow of fluid from the first and second orifices.

9. The drill bit of claim 7, further comprising:
a second valve for regulating the flow of fluid from the second orifice.
10. A wellsite system comprising:
a drill string;
a kelly coupled to the drill string; and
a drill bit comprising:
an interior cavity in fluid communication with a drill string; and
a first gauge pad located on the exterior of the drill bit, the first gauge pad having a first orifice in fluid communication with the interior cavity, wherein the drill bit is configured such that a fluid continuously flows from the first orifice.
11. A method of drilling a curved borehole in a subsurface formation comprising:
mounting a drill bit on a drill string, the drill bit comprising:
a drill bit comprising:
an interior cavity in fluid communication with a drill string; and
a first gauge pad located on the exterior of the drill bit, the first gauge pad having a first orifice in fluid communication with the interior cavity, wherein the drill bit is configured such that a fluid continuously flows from the first orifice;
substantially concurrently rotating the drill string and pumping the through the drill string to the drill bit.