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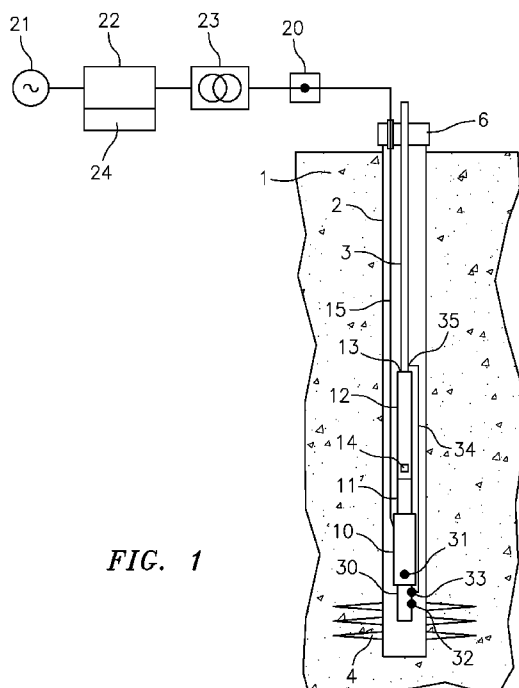
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(54) Title: METHOD AND SYSTEM FOR MONITORING MOVING ELEMENTS



(57) Abstract: An apparatus and method for sensing a rotational parameter of a rotating member of a downhole pumping system. The apparatus is capable of detecting motor rotation and pump operating conditions and includes control systems for methods utilizing the rotational parameters to control the operation of the downhole pumping system.



METHOD AND SYSTEM FOR MONITORING MOVING ELEMENTS

BACKGROUND OF THE DISCLOSURE

Field of the Disclosure

[0001] Embodiments of the present disclosure to downhole pumping systems used to pump fluids from wells and, and more particularly, to a method and system for detection, correction and monitoring of the rotational movement of an electric motor as part of a downhole pumping system.

Description of the Related Art

[0002] Electric Submersible Pumping (ESP) is a widely used method of artificial lift, whereby a pump and an electric motor are deployed in a borehole and are used to bring fluids, including liquid and gas, to the surface. Artificial lift is necessary when the natural well pressure is insufficient to do so by itself. The motor is powered via a length of electric cable rising to surface and thence connected to control equipment. Injection pumping is also used in the art whereby a pump and electric motor deployed in a borehole are used to inject fluids and solids (such as proppants) into a formation. Although induction type motors are dominant in the field of ESPs, permanent magnet motors are becoming more common and have a different set of problems to be solved to ensure safe and reliable control.

[0003] It has been found that achieving reliable operation of ESPs and optimum production is greatly assisted by downhole gauges. A typical gauge will include a sensor to measure the motor internal temperature, which allows the motor to be protected by stopping it if it gets too hot. Such a gauge will include a sensor to measure the pump intake pressure, which is the reservoir flowing pressure (pressure where fluid enters the borehole) referred to the intake. Controlling the pump to regulate intake pressure therefore regulates production. If the intake pressure drops too low it indicates insufficient fluid above the intake, with the possibility for the pump to run dry. This warning allows

the pump to be stopped or slowed down using the surface control equipment. Less commonly, despite its benefits, a discharge pressure sensor is fitted. This discharge pressure sensor gives the pressure of the fluid column above the pump and allows the pressure head across the pump (the difference of discharge and intake pressures) to be determined.

[0004] The process of installing a downhole pumping system is complex and entails several steps at which a three-phase power electrical joint, typically comprised of a connector, bolted or spliced must be made. Over many decades of experience there still remains a significant probability that the motor will turn in the wrong direction when first started due to mis-phasing of the three-phase power electrical joint. Even with best practice the possibility of incorrect rotation must be allowed for.

[0005] Another important aspect of controlling downhole pumping systems is the controlling of the speed of the motor. It is known in the art that measuring and reporting the angle of the rotating shaft of the motor is a very important parameter for robust and efficient control of permanent magnet motors. Most such control methods use techniques from the known broad family of vector control algorithms. In some submersible pumping applications, the angle must be estimated in the drive from surface voltage and current using an algorithm known in the art as an observer or estimator. Operating a drive using estimated angle is also known as sensorless control. In other industrial applications, such as robotics, it is usually feasible to connect an angle encoder to the shaft and not rely on sensorless control, as this gives the maximum robustness to rapid changes of load. However, in downhole pumping systems fitted with a conventional downhole gauge, the downhole gauges do not have the bandwidth to transmit shaft angle at a sufficiently high rate for sensor control.

[0006] When no gauge is fitted, then at start up, or after a restart, it is necessary to wait for the estimated time for fluid to arrive at surface before it can be determined whether the pump is rotating in the correct direction. It should be noted that such pumps used in ESP systems are predominantly centrifugal type pumps. The nature of such pumps is

that even when rotated in the wrong direction they will pump fluid until a significant head is reached, albeit not normally enough to produce fluid at surface. Hence even when a discharge pressure measurement is made, and increasing pressure indicates fluid flow, it is not possible to immediately determine whether the pump is rotating in the wrong direction.

[0007] Another problem in the prior art, and in particular with unconventional wells (shale formations for example), the ESP is often set in the sensibly horizontal section of the well. In such cases, the discharge pressure will not rise appreciably until the lifted fluid has entered the non-horizontal section, further delaying the ability to detect reverse rotation of the pump.

[0008] One practical result of a pump starting in the reverse direction is wasted time, which is very costly considering all the personnel and equipment tied up while waiting to know if the equipment is operating correctly or if it has to be recovered from the well. These costs are even higher for offshore operations, but often there is a further issue offshore. Typically, much larger pumps are used, and the pump bearings experience high rubbing loads when running reversed. These can lead to premature failure and large expense in lost production and workover to replace the pump.

[0009] In unconventional wells or wells that produce a lot of sand, it is important not to stop a running motor unless absolutely necessary. These wells contain much debris which is pumped up into the production tubing. When the pump stops, the debris falls back down the production tubing and into the pump and can cause it to seize or otherwise become damaged. Unconventional wells are typically deep and workover (repair) costs are extremely expensive. During start-up, a method that shortens the time to discovering reverse rotation and correcting it greatly reduces the initial amount of debris that can fall back down the production tubing and into the pump.

[0010] Progressive cavity pumps (PCPs) are another type of pump that can be driven by electric motors in ESP systems, with the motor and pump being deployed in the borehole.

PCPs are positive displacement and operate equally well in either sense of rotation in terms of pumping capability. Reverse rotation at start has the almost immediate effect of running the pump dry unless fluid has previously entered the production tubing that the pump is discharging into. Of course, once the fluid from the production tubing has been pumped out into the wellbore the PCP will be pumped dry. It is well known that a PCP will typically be damaged within a couple of minutes when run dry.

[0011] There is clearly a need for an improved means of detecting reverse rotation of an ESP system at start up and the capability of acting on it promptly. The present disclosure described herein below provides method and apparatus to accomplish this and additional benefits for ESP operations, independent of motor type and surface drive type.

SUMMARY OF THE DISCLOSURE

[0012] In accordance with some aspects of the present disclosure, systems and methods related to a novel downhole pumping system are disclosed. Various embodiments of a downhole pumping system incorporating a rotational movement sensor and control system are disclosed.

[0013] According to one aspect of the present disclosure, the downhole pumping system includes an electrical submersible pump assembly that includes a motor, a shaft, a pump, and at least one sensor system positioned to measure a rotational parameter of the shaft. The system includes a processing system to determine a measurement of the rotational parameter and determines if the shaft is rotating, the direction of rotation, the speed of rotation and the acceleration of rotation of the shaft. The system may include a control system to control the rotational movement of the shaft in accordance with the rotational parameter.

[0014] According to another aspect of the present disclosure, a method of controlling a downhole pumping system is disclosed. The method includes a desired rotational direction of the shaft and determining a rotational parameter of the shaft from the at least

one sensor system including determining if the shaft is rotating, in which direction the shaft is rotating, the speed that the shaft is rotating and the acceleration of the shaft. The method further includes controlling the rotation of the shaft based on the rotational parameter and the desired rotational direction.

[0015] According to yet another aspect of the present disclosure, a method determining a condition of the downhole pumping system is disclosed. The method includes determining whether the pump is in a stalled condition, a backspin condition, a speed fluctuation condition, a stuck condition, a stopped condition, or a constant speed condition.

[0016] Further areas of applicability will become apparent from the description provided in this disclosure. It should be understood that the disclosure and specific examples provided are for illustrative purposes and do not limit the scope of the present disclosure.

BRIEF DESCRIPTION OF THE DRAWINGS

[0017] So that the manner in which the above-recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this disclosure and are therefore not to be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments.

[0018] Fig 1 is a schematic representation of a downhole pumping system in accordance with the present disclosure.

[0019] Fig 2 is a schematic representation of an electrical diagram of a communication system of a downhole gauge.

[0020] Fig 3 is an isometric view of a rotation sensor system in partial section in accordance with an embodiment of the present disclosure.

[0021] Fig 4 is an isometric view of a transmitter assembly of a rotation sensor in accordance with an embodiment of the present disclosure.

[0022] Fig 5 is side view of a rotation sensor system in partial section in accordance with an embodiment of the present disclosure.

[0023] Fig 6 is an isometric view of a receiver of a rotation sensor system in partial section in accordance with an embodiment of the present disclosure.

[0024] Fig 7 is an isometric view of a receiver holder of a rotation sensor system in partial section in accordance with an embodiment of the present disclosure.

[0025] Fig 8 is a graphical representation of the signal output a rotation sensor system in accordance with an embodiment of the present disclosure.

[0026] Fig 9 is a circuit diagram of a Hall effect sensor in accordance with an embodiment of the present disclosure.

[0027] FIG. 10a is an illustration of a side view of an encoder of a rotation sensor system in accordance with an embodiment of the present disclosure.

[0028] FIG. 10b is an illustration of an end view of a receiver of an encoder of a rotation sensor system in accordance with an embodiment of the present disclosure.

[0029] FIG. 11 is circuit diagram of the receiver coils of an encoder of a rotation sensor system in accordance with an embodiment of the present disclosure.

[0030] FIG. 12 is a flow chart of a method of operating a downhole pumping system in accordance with an embodiment of the present disclosure.

DETAILED DESCRIPTION

[0031] In the following detailed description of the embodiments, reference is made to the accompanying drawings, which form a part hereof, and within which are shown by way of illustration specific embodiments by which the examples described herein may be practiced. It is to be understood that other embodiments may be utilized and structural changes may be made without departing from the scope of the disclosure.

[0032] Referring to Fig 1, there is shown a typical downhole pumping system installed in a wellbore. As is known, a borehole drilled in an earth formation 1 may be lined with casing 2 cemented to the surrounding formation. A motor 10 is coupled to a pump 12 via a motor seal 11. The pump discharge end 13 is attached to production tubing 3. Production fluid (not shown) enters the well via perforations 4 in the casing 2 and enters the pump at its pump intake 14. The production tubing 3 runs up the borehole through the wellhead 6 and on to surface production facilities. In a typical installation, motor 10 comprises a three-phase motor and is powered via a cable 15 which comprises a three-conductor electric cable, which runs up to surface alongside and clamped to the production tubing 3 in a manner well known in the art. The cable 15 then penetrates through the wellhead 6 and runs to a vented junction box 20. In the embodiment shown, surface electric power 21 is converted by drive unit 22 to a frequency and scaled voltage needed by the motor 10. The scaled voltage is then increased to the actual voltage needed by the motor 10, allowing for voltage drop in the cable, by transformer 23. The output of the transformer 23 is connected in the vented junction box 20 to the cable 15. In other embodiments, older installations for example, drive unit 22 may simply comprise a switch-board that passes the supply voltage directly to the transformer via a controllable contactor and protective fuses. In the current area of art, drive unit 22 is preferably a variable speed drive as this permits optimization of production and energy savings. A variable speed drive is in any case required for permanent magnet motors due to the need for synchronous control. A controller 24, whether separate or incorporated within the drive unit 22, can be used to stop and start the motor and potentially to reverse the

motor rotational direction by switching phase connections electronically or by switchgear as will be discussed more fully herein below.

[0033] In some wells, the casing 2 to production tubing 3 annulus is sealed above the motor 10 to prevent gas entering the casing. The seal (not shown) is well known in the art and is typically referred to as a packer. In this particular case, the cable 15 has to make a further penetration through the packer. It is well known in the art that cable electrical connections are made on either side of the packer penetrator.

[0034] Still referring to FIG 1, downhole gauge 30 is attached to the motor 10. Downhole gauge 30 contains electronics and usually has connections from its interior into the motor 10, which can be oil-filled, and to sensors mounted outside the gauge unit. Such sensors can include vibration and internal temperature sensors. A temperature sensor 31 can be fitted inside the motor 10 and connected to the downhole gauge 30, and a pressure sensor 32 to sense the pressure of the fluid surrounding the gauge. It is known in the art that the measured pressure is easily related to the pump intake pressure using estimated fluid density and the vertical height (elevation) between the pressure sensor 32 and the pump intake 14. If required, a second pressure sensor 33 can be used, connected by a sense tube 34 to a port in the production tubing immediately above the pump discharge end 13. This, again with a suitable known adjustment for elevation, is the discharge pressure measurement. In practice, the adjustments in pressure are small and rarely made.

[0035] Considering now the practical aspects of connecting the motor 10 to the drive unit 22, it can be seen that potential errors may be made in the sequence of phase connections at the motor, at any splices in the cable (not shown), at and below the well head penetration, and in the junction box 20. With the aforementioned downhole seal penetrator there exists two more such connections wherein potential errors may be made. Since the motor 10 is fully enclosed and deployed in the well, there is no possibility to check if connections have been swapped at some point in the lengthy sequence of actions followed to install such a system. Since errors are inevitably made, from time-to-time it is

difficult to predict whether the motor 10 will start in the correct rotational direction. Although the pumping system shown in FIG 1 illustrates an ESP type pump, alternative pumps and pumping schemes (other than lifting) may be used without departing from the scope of the present disclosure. For instance, embodiments of the present disclosure are well suited for use with injection pumping systems wherein the desired rotational direction of the motor will be opposite of that for a pumping system. In addition, the desired rotational direction of the motor will depend directly on the configuration of the pump and motor, i.e. their relational mounting scheme. In addition, a progressive cavity pump (PCP) when reversed will indeed pump fluid from the production tubing into the well.

[0036] Referring now to Fig 2, there is shown a depiction of a typical form of a prior art communication system 51 in which data and power is transferred via the motor star point 18 of the motor windings 19. There are numerous providers of downhole gauges offering this type of system and the following illustrative description is not limiting in its scope.

[0037] In the ideal case of a motor 10 that is perfect sinusoidally wound, surface electric power 21 (Fig. 1) that is a perfect sinusoidal drive voltage and a balanced cable 15, the motor star point 18 voltage would be zero with respect to ground 17. In practice, motor star point 18 is subject to voltage imbalances, voltage harmonics and transients from the voltage switching action of drive 22 (Fig. 1) (if used).

[0038] Still referring to Fig 2, a gauge surface unit 36 is connected via three inductors 40 attached to the cable 15 at the secondary side of transformer 23. The downhole gauge 30 is connected to the motor star point 18 by an inductor 41. Inductors 40 and 41 provide sufficient reactance at the motor electrical power frequencies to limit the high motor voltages to a safe level within downhole gauge 30 and gauge surface unit 36. AC or battery power is applied to local power supply 46 which supplies direct current (DC) power between ground 17 and inductor 40, typically on the order of 100 volts DC. Downhole power supply unit 42 recovers the power between inductor 41 and ground 17 and converts it to voltages required by the remaining electronic equipment. Downhole power supply unit 42 preferably draws a steady current. Signal conditioning and digitizing unit 45, using

techniques well known to those practiced in the art, converts an analog output from temperature sensor 31 and pressure sensor 32 to a digital form. Here a pressure sensor 32, such as a strain gauge device, and a temperature sensor 31, such as a thermocouple, are representatively shown as inputs to digitizing unit 45. Processor unit 43 receives the digital data from digitizing unit 45, and optionally processes it such as by calibration and filtering, and packages the measurements and status information into telemetry packets, which are then modulated by processor unit 43 and impressed upon inductor 41 such as by known techniques of varying the supply current according to binary ones and zeroes and communicated via a telemetry system.

[0039] In gauge surface unit 36, demodulation unit 47 demodulates the gauge data. Processor unit 48 validates the demodulated data and makes it available to controller 24 (Fig 1) using a known serial connection and data protocol such as Modbus. Depending upon the sophistication of the drive 22, two-way communication may be implemented, with the possibility to change the selection of gauge data being transmitted uphole in each telemetry frame via a telemetry system.

[0040] The communication system 51 of Fig 2 circulates gauge power and data in loop 50, wherein gauge current flows equally through the three motor cable conductors of cable 15 and the motor windings 19. The current returns through a distributed ground 17, primarily comprising the metallic motor, seal and pump construction and the production tubing. Cable 15 may also typically comprise a metallic cable armor which also provides an electrically conductive return path. This electrically conductive metalwork is earthed at the wellhead 6 (Fig 1) and also where it may touch the casing 2 at various points in the borehole. The water content of the borehole fluid may also provide a return path between this metalwork and the casing.

[0041] Still referring to Fig 2, the voltage from the secondary side of transformer 23 applied to the motor 10 is differential, that is it is differential between individual phases. There is no earth connection. The gauge power and communication is common mode, that is it is between the phases as a whole and earth. In principle, there is no interaction

between motor power and gauge power and data. In practice, and as described above, the motor star point 18 is not at zero motor voltage due to system imperfections. The large inductances of 19, 40 and 41 and the high capacitance 16 of the cable conductors to ground act as a low-pass filter. The distributed earth is of variable quality. Hence the common mode telemetry system experiences interference. Overall the effect of these factors is to severely restrict the gauge data bandwidth, typically to on the order of 10bits/s.

[0042] Now with reference to Fig 3, there is shown the bottom end of a representative submersible motor 10 in partial section view of an embodiment of the present disclosure. As will be described in more detail herein below, this embodiment advantageously utilizes the down hole gauge communications system described immediately herein above. The particular embodiment can be utilized with any motor 10, including submersible, and it should be appreciated by those skilled in the art that there are design and installation variations amongst the various manufacturers of these products which do not affect the scope of this disclosure.

[0043] One embodiment of a rotational sensor system 115 of the present disclosure is best described with reference to Figs 3, 4 and 5, wherein motor shaft 100 of motor 10 passes the end turns of the motor winding 101 (similar to motor windings 19 in FIG 2) and is supported by bearing 102. Motor shaft 100 can in some embodiments be hollow for the purposes of circulating the oil that fills the motor, though in some cases this benefit is foregone and the shaft is solid. Rotation transmitter assembly 103 is fastened to the end of the motor shaft 100. It is screwed in to the end of the shaft and secured with a grub screw 110 (or set screw) or a pin as shown in detail in Figs 4 and 5, although other means of attachment may be made without departing from the scope of the present disclosure. In the embodiment shown, the rotational transmitter assembly 103 is fully round and smooth and so does not create appreciable drag as it rotates with the shaft. Rotational transmitter assembly 103 may advantageously be made of an essentially non-magnetic material such as stainless steel. Two magnets 111, 112 are inserted into its end face

exposing opposite polarities wherein magnet 111 is shown having a North polarity facing outward and magnet 112 is shown having a South polarity facing outward. Magnets 111, 112 are preferably spaced close enough together that their flux passes from one to the other in a loop as will be more fully described herein below.

[0044] Receiver assembly 104 is secured to a stationary portion of the body of motor 10, and in this particular embodiment is secured by screw 105 into the receiver assembly holder 108 (Fig 7) and is held stationary with respect to rotating motor shaft 100. Referring briefly to Fig 6, receiver assembly coil 107 is wound on a former 106. Former 106 is preferably comprised of a magnetic material such as ferrite, carbon steel or bonded iron powder, in order to concentrate flux from the rotational transmitter assembly 103. It should be appreciated by those skilled in the art that receiver assembly holder 108 may be comprised of a non-magnetic material or a magnetic material shaped to enhance the sensitivity of the rotational transmitter assembly 103.

[0045] In operation, as the magnets 111, 112 of rotational transmitter assembly 103 rotate on motor shaft 100 and pass the receiver assembly coil 107 (Fig 6), a small voltage (electromotive force) will be induced, as is well known from elementary electromagnetic theory. The instantaneous polarity of the voltage will depend on the polarity of the magnet (111 or 112) facing the receiver assembly coil 107, the coil connection to receiver circuitry and the handedness of the coil turns thereon. Referring to Fig 8, there is shown representative output signals in the form of voltage signals versus time from the rotational sensor system 115 for one revolution of motor shaft 100 in accordance to a certain set of connections as discussed herein above. With the motor shaft 100 turning clockwise (typically with the convention of looking up hole or from the right in Fig 3), output signal 120 shows a positive voltage first as one magnet passes over receiver assembly coil 107, followed by a negative voltage as the second magnet passes over the receiver assembly coil. Conversely with the motor turning anti-clockwise, output signal 121 shows a negative voltage first as one magnet passes receiver assembly coil 107, followed by a positive voltage as the second magnet passes over the receiver assembly coil. By placing

the magnets 111, 112 close together, and within a typical range of operating speeds, the voltage signals will appear as a doublet. In so doing, the doublet cannot be confused with the large gap in the time between positive and negative pulses corresponding to the alternative but longer spacing between magnets around the circumference of rotational transmitter assembly 103. Simple circuitry (not shown) such as positive and negative voltage comparators and logic gates as may be envisioned by one skilled in the art, that will detect the sequence of positive and negative voltage signals, and their rate of occurrence. Depending on the details of the particular embodiment and the magnetic flux path, the signals may not be simple doublets and can, for example, be positive or negative pulses. It should be appreciated that embodiments of the present disclosure advantageously provide a means of determining the rotational direction of shaft 100 as well as its rotational speed. Although the rotational transmitter assembly 103 of the rotational sensor system 115 is shown attached to motor shaft 100, it may be attached to any other shaft or rotating part of the ESP system such as a coupling or pump shaft (not shown). It will further be appreciated that there are several simple variations of this embodiment. For example, the magnets may be inserted directly into holes drilled in the shaft end if the shaft is made of non-magnetic material. In another example the magnets may be installed radially (transversely to the shaft axis) with an opposing radial receiver coil. In addition, and to improve signal strength, the magnetic reluctance of the transmitter-receiver circuit can be reduced by incorporating magnetic material such as steel within the transmitter behind the magnets.

[0046] A further advantage of this particular embodiment of the present disclosure is that it only requires one wire connected to receiver assembly coil 107 of receiver assembly 104 to pass from the motor 10, which can be oil-filled, at borehole pressure into the gauge electronics at atmospheric pressure. The other end of receiver assembly coil 107 can be connected to the housing of downhole gauge 30 and so it uses the existing metallic continuity to be accessible to the gauge electronics. In ordinary industrial applications known Hall effect sensors provide effective receivers, but in the present application their submersion in oil at high downhole pressure and temperature can severely limit the life

of these components. In addition, several connections may be needed for their operation, each being a potential point of failure. However, Hall sensors have the benefit that they respond to magnetic flux independent of the shaft speed, whereas a pickup coil electromotive force increases with shaft speed. Hall sensors can therefore be advantageous at low rotational speeds, and their use falls within the scope of embodiments of the present disclosure.

[0047] Now referring to FIG. 9, there is shown a circuit diagram of an embodiment of a Hall sensor 251 can be used in a novel manner to implement the direction sensing with only two wires connected to the gauge. Hall sensor 251 is of the known linear type, such as may be obtained from Allegro MicroSystems LLC, in which in the absence of a magnetic field passing through the sensor, the output 252 sits at approximately half the supply voltage on connections 253 and 254. The supply voltage is provided by the gauge and ordinarily the output 252 would form a third connection to the gauge for measurement. The output signal voltage on output 252 will increase or decrease according to the polarity of the magnetic flux passing through the sensor. However, in the given embodiment, output 252 is connected to transistor 255 and (emitter load) resistor 256. When output 252 increases, the current through resistor 256 will increase and conversely if output 252 decreases, the current through resistor 256 will decrease. As will be evident to one ordinarily skilled in the art, the resistor 256 current is drawn through the connections 253 and 254. Hence when magnetic flux passes through Hall sensor 251 the supply current will increase or decrease according to its direction. In this way, only connections 253 and 254 need to pass into the gauge electronics compartment. One of these connections can potentially make use of the equipment metalwork as a conductor. In a practical implementation the circuitry of FIG. 9 would be encapsulated to provide protection from the motor oil and contamination, using a material such as epoxy. Referring to FIG 4, the same axially mounted magnet 111, 112 configurations may be used, with the Hall sensor 251 positioned in the same location as receiver assembly 104 in FIG 5. Alternatively, the magnets may be disposed radially on motor shaft 100 and the Hall sensor 251 located

radially opposite. It has been discovered that the idealized output signals 120 and 121 in FIG 8 are readily achieved over a very wide speed range in such an embodiment.

[0048]

[0049] In another embodiment, although not shown, a receiver assembly 104 whose inductance is measured, such as by impedance measurement or by use as one of the frequency-determining elements in an electronic oscillator, which are methods known to one ordinarily skilled in the art, can be used to sense variation in the magnetic reluctance of the motor shaft 100 caused by notches or other magnetically permeable variations positioned thereon.

[0050] The embodiment of rotational sensor system 115 described immediately herein above is but a single embodiment of the present disclosure for implementing an encoder signal falling within the scope of this disclosure that measures rotational parameters to provide information relevant to shaft rotation and speed. While it is an important discovery, the particular embodiment of rotational sensor system 115 discussed directly herein above does not however provide an incremental or absolute shaft rotation angle. Such shaft angle information may be useful in determining whether motor shaft 100 has moved between attempted starts. This information would be helpful in the event of a stuck pump as will be described more fully herein below. Such angular position information may also be useful, for example, if a higher-speed telemetry system is available or for small motors where the drive itself is placed downhole.

[0051] Referring now to Figs 10a and 10b, there is shown an embodiment of a rotational sensor, or encoder, 201 of the present disclosure that measures rotational parameters to provide information relevant to shaft rotation and speed as well as an absolute shaft angle encoder. A disc comprises a rotating transmitter 200 and is comprised of a magnetically permeable material, wherein such magnetically permeable material may include carbon steel, is attached to the end of motor shaft 100. Rotating transmitter 200 has an end face at an angle relative to the transverse section of the motor shaft 100. In an alternative

embodiment, rotating transmitter 200 may be incorporated into motor shaft 100 by simply forming a suitable angled face across the end of the motor shaft. In addition, if it is desired to minimize drag, the angled end face may be restored to its normal square end using a complementary wedge of essentially non-magnetic material such as stainless steel. Best shown with reference to FIG. 10b, receiver assembly 109, mounted in a manner similar to that described herein above with reference to receiver assembly 104, comprises four coils 107A, 107B, 107C, 107D opposing the transmitter 200 wherein the coils are disposed evenly about the circumference of the receiver assembly. It should be appreciated that the inductance of each coil 107A, 107B, 107C, 107D will vary with its distance, from the face of the transmitter 200, or the gap formed therebetween, which varies sinusoidally with shaft rotation. In operation, and with reference to any two adjacent coils, the inductance of one will vary in sympathy with the sine of the shaft angle and the other will vary in sympathy with the cosine of the shaft angle. In such an embodiment of the present disclosure, using the output of the sine and cosine, the absolute shaft angle relative to a reference point may readily be deduced. With reference to coils that are diametrically opposed on receiver assembly 109, their inductances will vary together but will be 180 degrees apart, so as one inductance increases the other will reduce. Although the transmitter 200 of the encoder 201 is shown attached to motor shaft 100, it may be attached to any other shaft or rotating part of the ESP system such as a coupling or pump shaft (not shown).

[0052] Now referring to FIG. 11, a circuit diagram shows how the coils 107A and 107B may be wired in series as a half-bridge and driven by AC voltage, typically in the tens or hundreds of kilohertz range depending on anticipated shaft rotational speed. A similar circuit (not shown) may be used for coils 107C and 107D. The mid-point AC voltage will be amplitude modulated as the shaft rotates and the inductances vary. This amplitude modulated voltage is readily demodulated as in block 113 by rectification and low-pass filtering, giving the sine and cosine of shaft angle from the respective pairs of coils. These signals may be converted to angle by means of a phase locked loop well known in the processing of resolver signals and digital radio receivers.

[0053] Having regard to the limited bandwidth system of typical downhole gauges 30 as hereinbefore outlined, it is not feasible to transmit the shaft angular position in real-time at a rate needed by variable speed drives for vector control. For example, a motor turning at 3600rpm would typically need at least ten readings per rotation or 600 measurements per second to enable such control. However, utilizing embodiments of the present disclosure, the direction and speed can be transmitted every ten seconds or so and the shaft angle may be transmitted from time-to-time as needed wherein such transmission rates are easily accommodated by the communication system 51 (Fig 2) of existing downhole gauges 30 (Fig 1).

[0054] One particularly useful aspect of embodiments of the present disclosure includes that during make-up of the downhole assembly at surface before running into the borehole, the motor shaft 100 may be turned manually and the gauge readings from the encoder 201 or rotational sensor system 115 can be used to confirm the correct measurement of direction.

[0055] Now referring to FIG. 12, there is a flowchart showing the operation of an embodiment of the present disclosure with reference to the various figures described herein above. In step 300, drive 22 is set to output the motor voltage phase sequence to what is intended to be the forward rotational direction, where forward rotational direction is the correct sense for pumping if the system is connected as intended or the opposite direction if injection is intended. The drive can be of known vector or scalar type or a simple switchboard operating from a fixed power supply. As described herein above, the required direction of rotation will be determined by the pump and motor configuration as well as the desired effect, i.e. lifting or injection. In step 301, downhole gauge 30 is put into start-up mode where it transmits status data bits for direction of rotation and whether the motor shaft 100 of motor 10 is rotating. As described herein above, downhole gauge 30 may also transmit pressure and temperature measurements during the start-up mode. During this step, readings such as vibration might be omitted in order to make best use of the limited bandwidth system. In step 302 the motor is started in using the output

voltage from drive 22 configured to be in the what is intended to be the forward rotational direction. In step 303 controller 24 monitors the downhole gauge 30 readings during starting of the motor 10. After controller 24 starts the motor 10 and observes the downhole gauge 30 readings to determine whether rotation is detected, and if rotation is detected, the actual rotational direction. In step 304, and preferably once enough time has passed to be confident of the readings from the downhole gauge 30, for example after several telemetry updates, perhaps a minute, the controller 24 compares the readings from the downhole gauge with the intended operating direction. If they are the same, the downhole gauge 30 is put back into normal mode and the controller 24 indicates to the operator that starting was successful and in step 305 the phase settings are saved. If in step 304 the readings from the downhole gauge 30 and the intended forward rotational direction are not the same, the controller 24 stops the motor in step 306, and in step 307 drive 22 outputs the motor voltage phase sequence for the opposite rotational direction and in step 308 controller 24 restarts motor 10 in the opposite direction. In step 304 controller 24 again checks the downhole gauge 30 readings to confirm correct direction or to signal a fault. If it is correct, controller 24 preferably saves the correct phase sequence into storage, such as non-volatile memory storage, in step 305 so that it can always start correctly the first time after any restartable surface alarm or power loss, or after a planned stop. Once the correct phase sequence has been saved drive 22 takes over the control of motor 10 in step 309.

[0056] It should be appreciated by one skilled in the art that variations of the processes and apparatuses described herein above may be easily accomplished and remain within the scope of embodiments of the present disclosure. For example, in an alternative embodiment the downhole gauge may be configured to automatically switch into starting mode whenever it senses that the motor is not turning, and revert to normal mode a few minutes after starting is successful, thus avoiding the need for communication to the downhole gauge from surface. Two binary bits from the apparatus of the present disclosure are sufficient to indicate rotation and direction. The bits occupy very little

bandwidth and might be transmitted in all or occasional telemetry frames through communications system 51, without a special mode.

[0057] In certain embodiments, the controller 24 of the present disclosure is capable of advising an operator of incorrect rotational condition of the motor 10 and further to allow the operator to decide whether to stop and restart the motor, rather than a fully automated process. An example of where this method embodiment is useful is if it is preferred to physically rewire the phase connections at the drive so that the pump will start correctly when the controller is left to operate in its normal rotational direction.

[0058] It is known in the art that it is sometimes difficult to start a pump's rotational movement, such as when it is filled (or partially filled) with sand. As is known in the art, a rocking start is a sequence of forward and reverse starts at different levels of intensity and is used to try and free the pump of sand. Excessive starting intensity and rocking risks damaging the pumping system including breaking of the motor or pump shaft. In such cases, aspects of the present disclosure advantageously allow an operator to know if the pump shaft has moved during a start attempt, and provides a further indication of the severity of the "sticking" and how to proceed such as extending, changing or stopping the rocking sequence. In embodiments related to encoder 201, the shaft encoder transmitting the shaft angle at 10 – 20 second intervals to the controller will permit such information to be interpreted.

[0059] As herein described herein above with respect to the prior art control of downhole pumping systems, prior art downhole gauges do not have the bandwidth to transmit shaft angle using known sensors at a sufficiency high rate for sensor control of the motor. In accordance with embodiments the present disclosure described herein above, an analogue signal indicating shaft angle can be transmitted to surface control systems by methods as now described. By way of an example, progressive cavity pumps rotate at only a few hundred rpm, therefore the shaft rotation rate is only a few Hertz (Hz). Still considering the same example, when the shaft is rotating at 240rpm the rate is 4Hz. This rate may be low enough for a downhole gauge to transmit a (preferably sinusoidal)

modulation, in this example at 4Hz, of the gauge supply voltage or load current, and yet be separable from the sending of downhole data using a telemetry system by employing known filtering methods. The surface control equipment of the present disclosure can use the sinusoidal variation to determine the shaft angle, in conjunction with a rotational direction measurement as hereinbefore described. Alternatively, if a separate wire (not shown) is used for telemetry to surface, commonly known as an instrument or tubing encapsulated cable (TEC) cable, the telemetry can be at a relatively high rate and the modulation used to cover a wide range of shaft speeds. It is important to note, from a practical perspective, any such means of establishing a remote shaft sensor for motor control purposes must recognize that downhole equipment has a significant probability of failure over its lifetime and of infant mortality. In such situations the surface drive would need to have a fall-back sensorless method of control if a costly workover is to be avoided.

[0060] In addition to the advantages described herein above, during operation of the rotational sensor of the present disclosure, there exists many other conditions that the present disclosure may provide. For example, a stall condition of the motor shaft 100 may be detected, such as when the drive 22 loses control of a downhole permanent magnet motor. Warning of the stall condition from the present disclosure will allow the controller 24 to quickly stop the motor 10, preventing the motor rotor from overheating due to eddy currents inducted by the rotating stator field, and potential subsequent demagnetization. Another such advantage of embodiments of the present disclosure is the ability to detect backspin of the pump. It is known that in certain downhole pumping systems that in the event of power failure, or other types of failures, there exists a column of production fluid in the production tubing 3 above the pump 12. As the column of fluid drains back into the wellbore the pump may be driven backwards, or backspin, and drive the motor in the reverse direction thereby. In certain instances, such as in systems using permanent magnet motors, the motor may produce a hazardous voltage in a backspin condition. The backspin condition will continue, with the fluid column in the tubing draining, until the forces in the system come into balance. In addition, the operator may need to know when the draining and backspin has ceased, or at least slowed, before restarting the motor.

Embodiments of the present disclosure provide an operator with such rotational parameters as shaft movement, direction and speed, information of the motor and pump. Another advantage of embodiments of the present disclosure is the ability to detect frictional changes, which translate directly into acceleration and speed changes, within the system, such as a rubbing rotor. It should be appreciated by those skilled in the art that embodiments of the present disclosure employing encoder 201 provide angular shaft speed from which quadrant to quadrant (between coils 107A, 107B, 107C, 107D) variations, and acceleration thereby, may be determined that may be attributed to such frictional changes.

[0061] Although described herein with reference to synchronous permanent magnet motors, the present disclosure is particularly useful with asynchronous (induction) motors as used widely with ESPs. Such induction motors are typically operated by setting the electrical frequency and voltage of the motor. As is well known in the art, the speed of an induction motor operated at constant frequency will vary with load. Surface controllers can estimate motor speed in order to adjust the frequency to achieve a constant speed. However, a downhole rotational sensor system of the present disclosure will permit transmission of speed or speed change so as to give direct feedback to the drive 22.

[0062] While the foregoing is directed to embodiments of the present disclosure, other and further embodiments of the disclosure may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.

WHAT IS CLAIMED IS:**CLAIMS**

1. An apparatus, comprising: an electrical submersible pump assembly including a motor, a shaft, a pump, and at least one sensor system positioned to measure a rotational parameter of the shaft.
2. An apparatus of claim 1, further comprising a processing system being configured to determine one or more measures of the rotational parameter of the shaft from a signal output from the at least one sensor system.
3. An apparatus of claim 2, further comprising: a control system to cause the shaft to rotate in a first rotational direction, the processing system determines the first rotational direction and then compares the first rotational direction to a desired rotational direction.
4. An apparatus of claim 3, whereby the control system further causes the shaft to rotate in the desired rotational direction.
5. An apparatus of claim 3, whereby the control system further causes the shaft to rotate in an opposite rotational direction to the desired rotational direction.
6. An apparatus of claim 3, whereby the control system further causes the shaft to rotate alternatively between the desired rotational direction and the opposite rotational direction.
7. An apparatus of claim 1, wherein the at least one sensor system comprises a transmitter assembly and a receiver assembly.
8. An apparatus of claim 7, wherein the transmitter assembly is attached to the shaft and the receiver assembly is attached to a stationary portion of the motor.
9. An apparatus of claim 1, wherein the rotational parameter includes a rotational direction of the shaft.

10. An apparatus of claim 1, wherein the rotational parameter includes at least one of a rotational speed, an acceleration or an angular position of the shaft.
11. A method, comprising: providing an electrical submersible pump assembly including a motor, a shaft, a pump, at least one sensor system positioned to measure a rotational parameter of the shaft, a processing system, and a control system, determining a rotational parameter of the shaft from an output signal from the at least one sensor system.
12. A method of claim 11, further comprising: determining a first direction of rotation of the shaft responsive to the output signal from the at least one sensor system.
13. A method of claim 12, wherein the determining the first direction of rotation of the shaft responsive to the output signal from the at least one sensor system further includes: causing the shaft to rotate in the first direction of rotation and then comparing the first direction of rotation to a desired rotational direction.
14. A method of claim 13, whereby the control system further causing the shaft to rotate in the desired rotational direction.
15. A method of claim 13, whereby the control system further causing the shaft to rotate in an opposite rotational direction to the desired rotational direction.
16. A method of claim 13, whereby the control system further causes the shaft to rotate alternatively between the desired rotational direction and the opposite rotational direction.
17. A method of claim 11, wherein the determining of a rotational parameter includes determining a rotational direction, a rotational speed, an acceleration and an angular position of the shaft.
18. A method of claim 11, whereby the control system further controlling the shaft to rotate based on the rotational parameter.

19. A method of claim 11, further comprising communicating the output signal to the processing system via a telemetry system, a TEC cable or a limited bandwidth system.
20. A method of claim 11, further comprising detecting an operating condition of the pump.
21. A method of claim 20, wherein the operating condition of the pump includes a stall condition, a backspin condition, a speed fluctuation condition, a stuck condition, a stopped condition, and a constant speed condition.

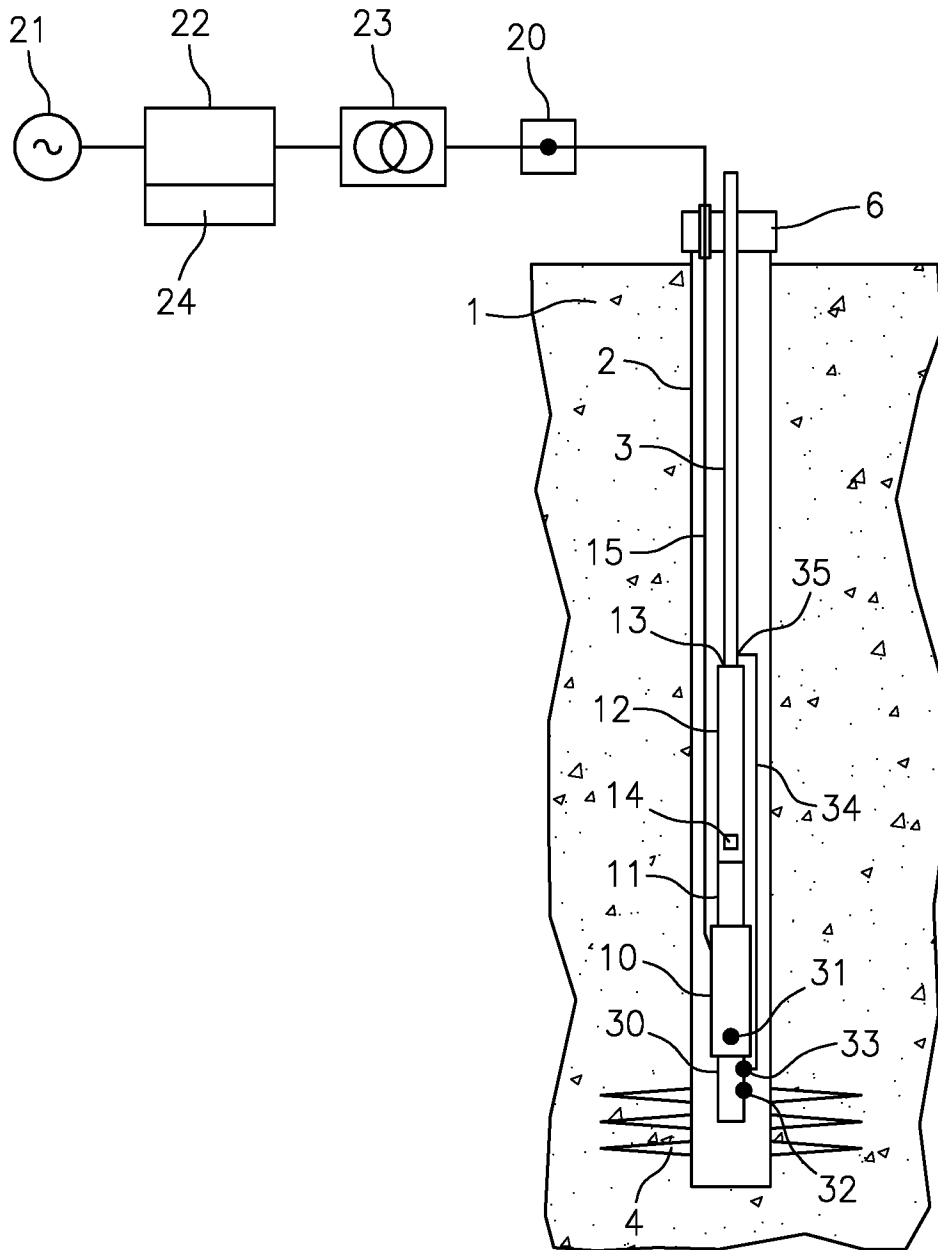


FIG. 1

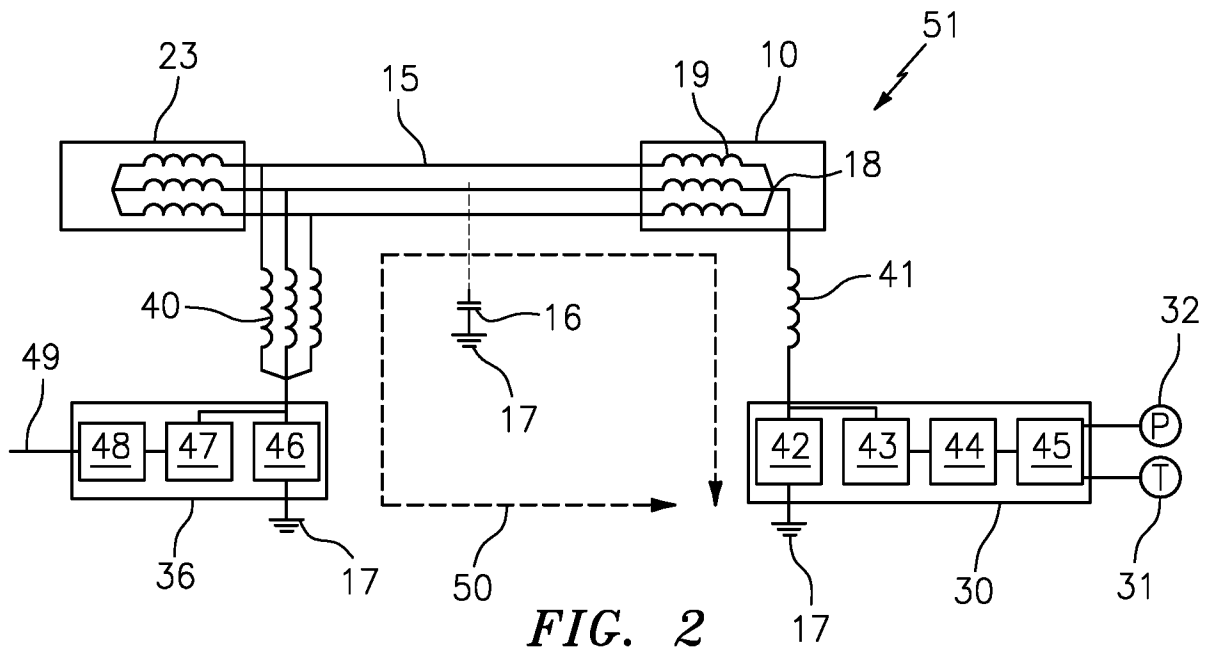


FIG. 2
(PRIOR ART)

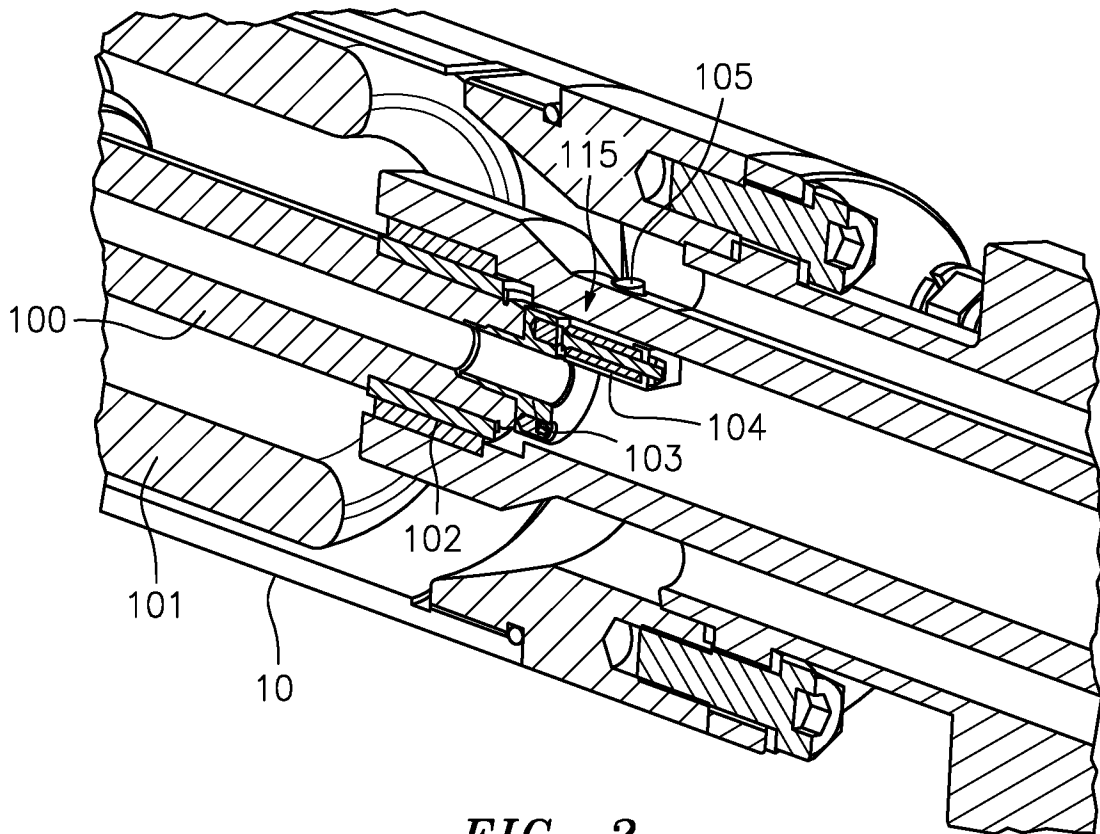


FIG. 3

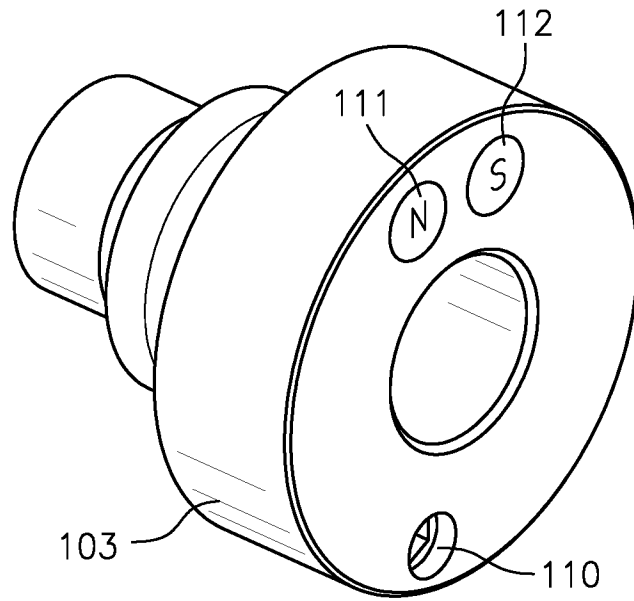


FIG. 4

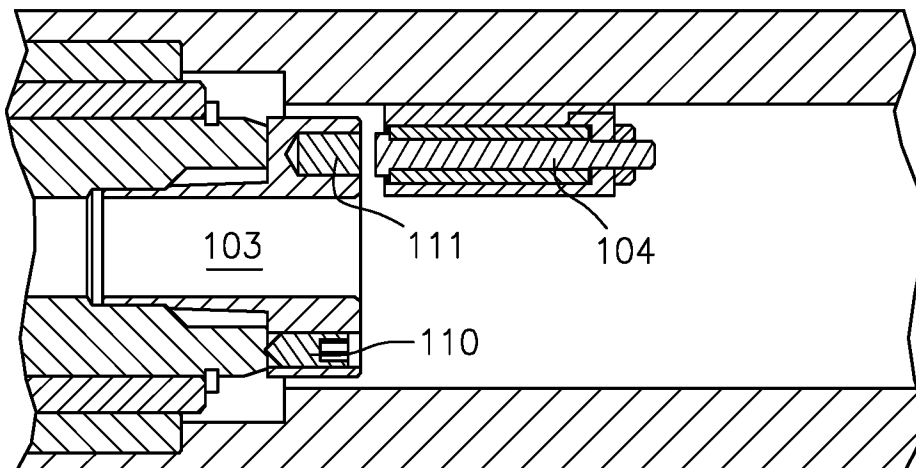


FIG. 5

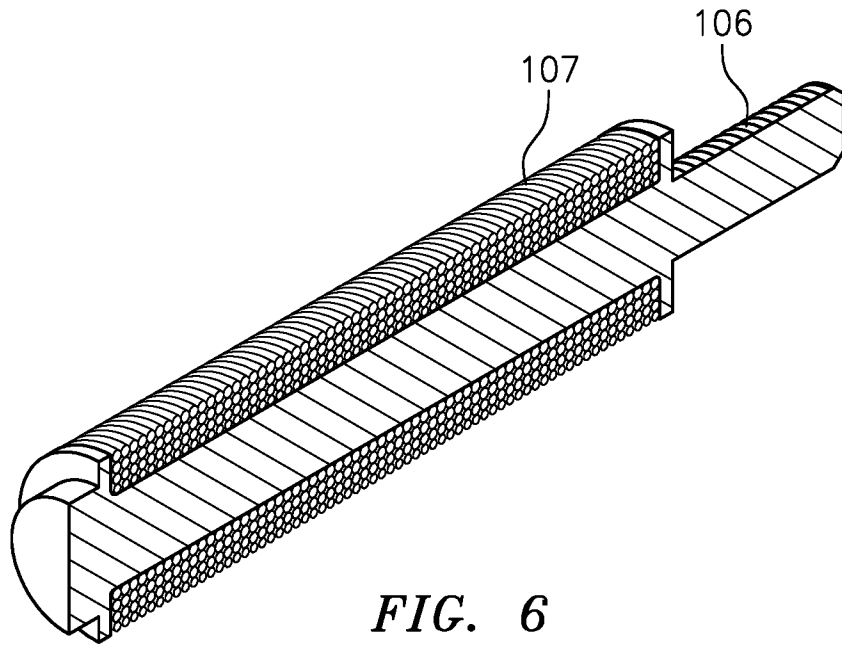


FIG. 6

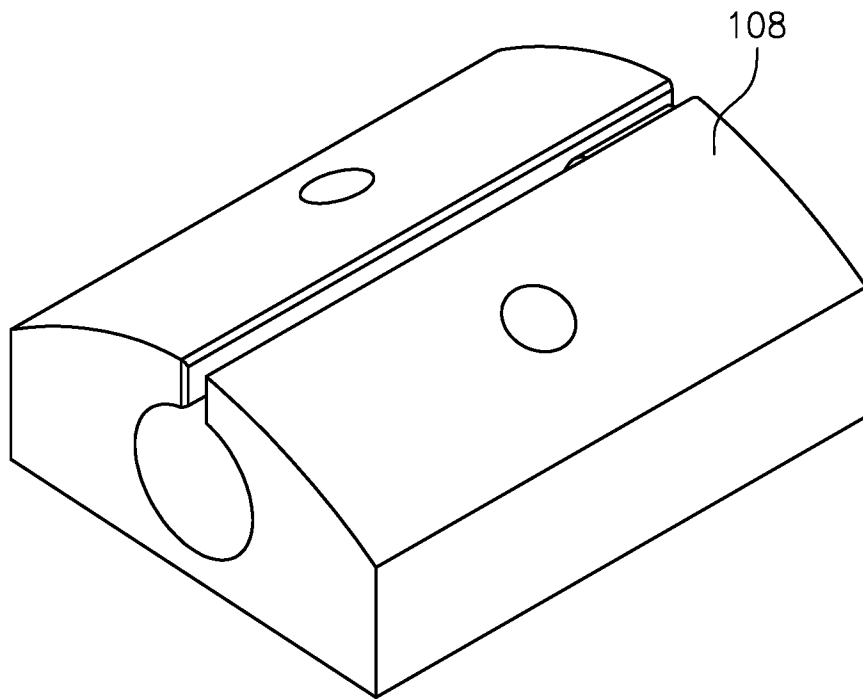


FIG. 7

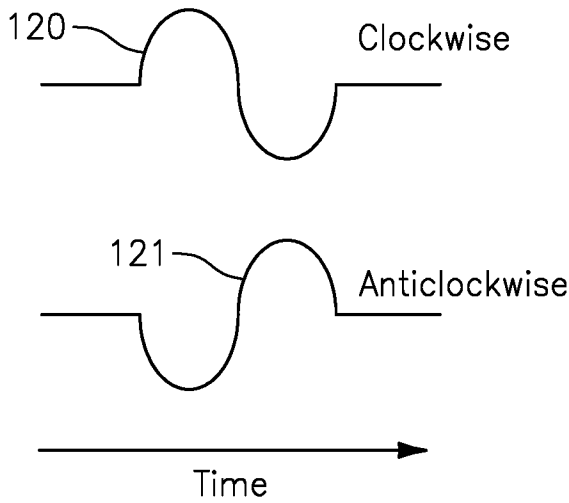


FIG. 8

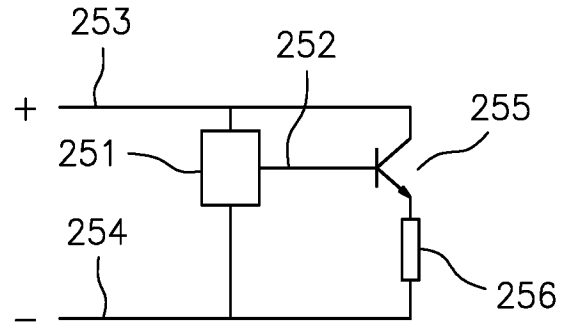


FIG. 9

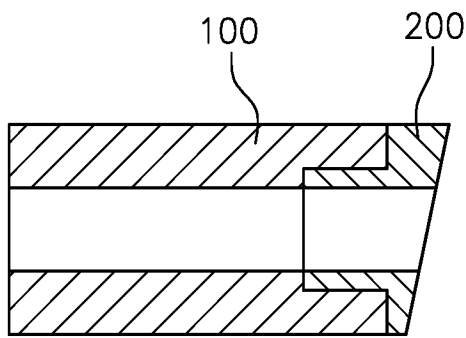


FIG. 10a

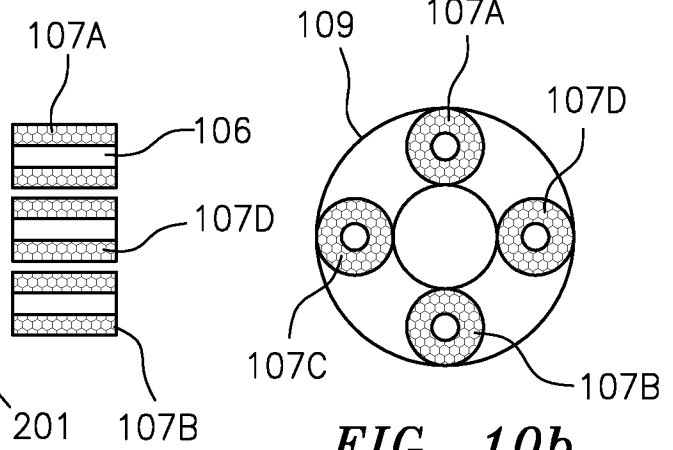


FIG. 10b

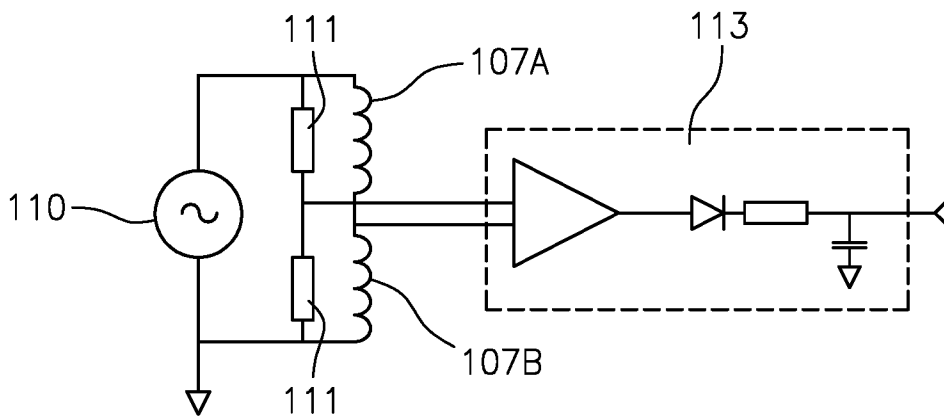


FIG. 11

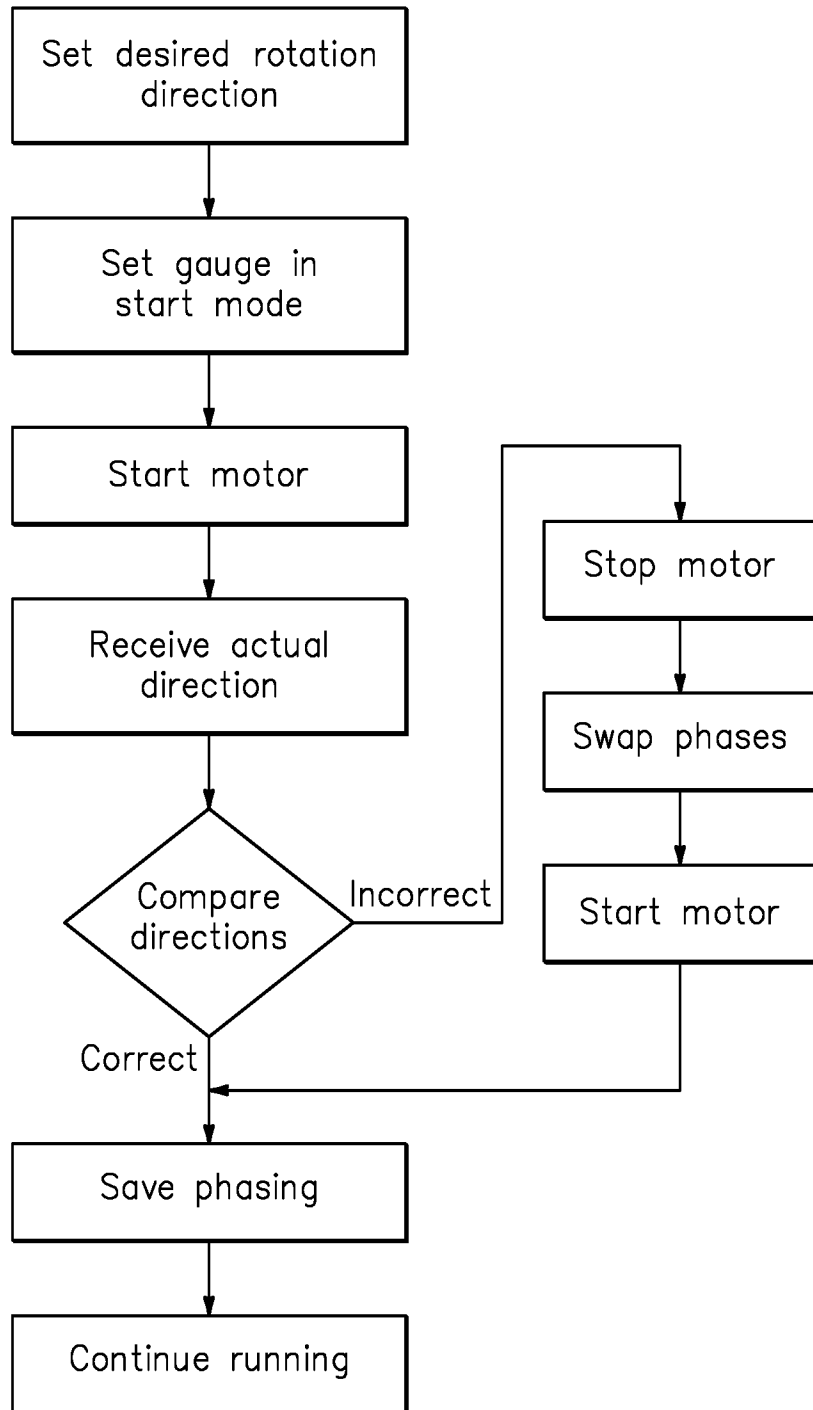


FIG. 12

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US 18/43308

A. CLASSIFICATION OF SUBJECT MATTER
 IPC(8) - G01P 13/04, F04D 13/10, F04D 15/00 (2018.01)
 CPC - G01P 13/04, F04D 13/10, F04D 15/00

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

See Search History Document

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

See Search History Document

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

See Search History Document

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X --- Y --- A	US 2012/0257995 A1 (True) 11 October 2012 (11.10.2012) entire document, especially title, abstract, para [0009].	1, 2, 7, 9, 11-12, 20 ----- 3-5, 19 ----- 6, 8, 10, 13-18, 21
Y --- A	US 7,953,575 B2 (Schoonover) 31 May 2011 (31.05.2011) entire document, especially Fig. 1, title, and abstract.	3-5 ----- 6, 8, 10, 13-18, 21
Y	US 2013/0092439 A1 (Mauldin et al.) 18 April 2013 (18.04.2013) entire document, especially Fig. 1, title, and abstract.	19
A	US 2011/0033314 A1 (Pliitt et al.) 10 February 2011 (10.02.2011) entire document.	1-21
A	US 2010/0247335 A1 (Atherton) 30 September 2010 (30.09.2010) entire document.	1-21

Further documents are listed in the continuation of Box C.

See patent family annex.

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"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

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"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

10 September 2018

Date of mailing of the international search report

11 OCT 2018

Name and mailing address of the ISA/US

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