

(19) World Intellectual Property Organization
International Bureau



(43) International Publication Date
2 April 2009 (02.04.2009)

PCT

(10) International Publication Number
WO 2009/042785 A2

(51) International Patent Classification:

E21B 25/10 (2006.01) **E21B 49/02** (2006.01)
E21B 25/16 (2006.01)

(21) International Application Number:

PCT/US2008/077705

(22) International Filing Date:

25 September 2008 (25.09.2008)

(25) Filing Language:

English

(26) Publication Language:

English

(30) Priority Data:

60/975,065	25 September 2007 (25.09.2007)	US
12/236,206	23 September 2008 (23.09.2008)	US
12/236,295	23 September 2008 (23.09.2008)	US
12/235,859	23 September 2008 (23.09.2008)	US

(71) Applicant (for all designated States except US): **BAKER HUGHES INCORPORATED** [US/US]; P.O. Box 4740, Houston, TX 77210-4740 (US).

(72) Inventors; and

(75) Inventors/Applicants (for US only): **CASTILLO, Homero** [PE/US]; 5222 Sycamore Villas Drive, Kingwood, TX 77345 (US). **GEORGI, Daniel, T.** [US/US]; 14202 Chadbourne, Houston, TX 77079 (US). **PATTERSON, Douglas, J.** [US/US]; 8219 Northbridge Drive,

Spring, TX 77379 (US). **HALL, Larry, M.** [US/US]; 3315 Redwood Lodge Drive, Kingwood, TX 77339-2503 (US). **GOLD, Randy** [US/US]; 14111 Wickersham Lane, Houston, TX 77077 (US). **REIDERMAN, Arcady** [US/US]; 1918 Baker Trail, Houston, TX 77094 (US).

(74) Agents: **CARSON, Matt, W.** et al.; Baker Hughes Incorporated, P.O. Box 4740, Houston, TX 77210-4740 (US).

(81) Designated States (unless otherwise indicated, for every kind of national protection available): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PG, PH, PL, PT, RO, RS, RU, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States (unless otherwise indicated, for every kind of regional protection available): ARIPO (BW, GH, GM, KE, LS, MW, MZ, NA, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MT, NL,

[Continued on next page]

(54) Title: SENSORS FOR ESTIMATING PROPERTIES OF A CORE

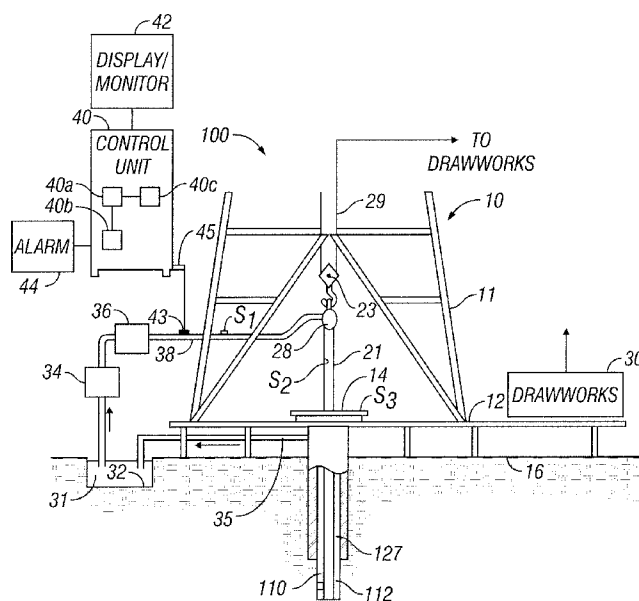


FIG. 1A

(57) Abstract: A method for estimating a property downhole is provided, which, in one aspect, may include receiving a core at a receiving end of a downhole tool while removing a portion of the received core distal from the receiving end of the tool, obtaining measurements by a sensor downhole, and processing the measurements to estimate the property of interest.

WO 2009/042785 A2



NO, PL, PT, RO, SE, SI, SK, TR), OAPI (BF, BJ, CF, CG,
CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:

- *without international search report and to be republished
upon receipt of that report*

SENSORS FOR ESTIMATING PROPERTIES OF A CORE

Inventors: Homero Castillo; Dan Georgi; Doug Patterson;
Larry Hall; Randy Gold and Arcady Reiderman

5

BACKGROUND OF THE DISCLOSURE**Field of the Disclosure**

[0001] The disclosure herein relates generally to obtaining cores from a formation and
10 estimating one or more properties of interest downhole.

Description of the Related Art

[0002] To obtain hydrocarbons such as oil and gas, wells (also referred to as
“wellbores” or “boreholes”) are drilled by rotating a drill bit attached at a bottom end of a
drill string. The drill string typically includes a tubular member (made by joining pipe
15 sections) attached to a top end of a drilling assembly (also referred to as the “bottomhole
assembly” or “BHA”) that has a coring drill bit (or “coring bit”) at the bottom end of a
drilling assembly. The coring bit has a through-hole or mouth of a selected diameter
sufficient to enable the core to enter into a cylindrical coring barrel (also referred to as a
“liner”) inside the drilling assembly. One or more sensors are placed around the core
20 barrel to make certain measurements of the core and of the formation surrounding the
wellbore drilled to obtain the core. The length of the core sample that may be obtained is
limited to the length of the core barrel, which is generally a few feet long. Such systems,
therefore, are not conducive to continuous coring (coring beyond the core barrel length)
or for taking measurements of cores longer than the core barrel length. To core for an
25 extended wellbore length, the coring operation is stopped in order to either retrieve the
core from the core barrel or to raise the drill string above the top of the core to
disintegrate the core with the drill bit before continuing the drilling of the wellbore. It is,
therefore, desirable to continuously core and obtain measurements to estimate one or

more properties of the core and of the surrounding formation to obtain tomograms of the cores and of the formation, and to selectively store core samples from more than one depth, substantially without stopping the drilling operation.

[0003] Therefore, there is a need for an improved apparatus and method for coring and
5 making measurements relating to various properties of the cores and the formation.

SUMMARY

[0004] The present disclosure, in one aspect, provides systems, apparatus and methods for continuous or substantially continuous coring of a subsurface formation. In one aspect, a method may include: drilling into a formation to retrieve a core from the formation; receiving the retrieved core into a chamber at an open end of a chamber; and removing a portion of the core uphole of the open end of the chamber so as to continue to receive the core into the chamber as the drilling continues.

[0005] An apparatus, according to one embodiment, may include a drill bit that is configured to drill into a formation to retrieve a core from the formation; a chamber that receives the core via an open end of the chamber; a cutting device configured to remove a portion of the core uphole of the open end of the chamber so that the chamber continues to receive the core as the drill bit continues to core the formation. In one aspect, the systems, apparatus and methods allow for continuous coring operations.

[0006] In another aspect, apparatus and methods are provided for selectively storing core samples. In one aspect, a method may include: receiving a core via a first end of a first chamber; moving a portion of the core into a second chamber from a second end of the first chamber; cutting the core proximate to the second end of the first chamber; and storing the cut core in the second chamber. The method may further include continuing to cut the core proximate to the second end of the first chamber so as to continue to receive the core into the first chamber. The method may further include repeating the above-noted process to selectively store in the second chamber additional core samples obtained at different formation depths.

[0007] In another aspect, systems, apparatus and methods are provided for estimating a property of a core and/or formation and/or the wellbore fluid and/or for performing tomography of a continuously obtained core. In one aspect, a method may include

estimating a property of interest of a continuously retrieved core using at least one sensor placed proximate to the core. The estimated property of interest may be utilized to provide a two-dimensional or three-dimensional tomogram of the property of interest of the core.

- 5 **[0008]** Aspects of the apparatus and methods disclosed herein have been summarized broadly to acquaint the reader with the subject matter of the disclosure and it is not intended to be used to limit the scope of the concepts, methods or embodiments related thereto of claims that may be made pursuant to this disclosure. An abstract is provided to satisfy certain regulatory requirements and is not to be used to limit the scope of the
- 10 concepts, methods and embodiments related thereto to the claims that may be made pursuant to this disclosure.

BRIEF DESCRIPTION OF THE DRAWINGS

[0009] For detailed understanding of the present disclosure, references should be made to the following detailed description of the apparatus and methods for retrieving cores and estimating one or more properties or characteristics of the core and formation, taken in
5 conjunction with the accompanying drawings, in which like elements have generally been given like numerals, wherein:

FIG. 1 (comprising **FIGS. 1A** and **1B**) is a schematic diagram of a drilling system for coring and estimating one or more parameters of interest of a core and a formation associated therewith, wherein **FIG. 1A** shows an exemplary surface apparatus and **FIG.**
10 **1B** shows an exemplary downhole apparatus of the drilling system;

FIG. 2 is a schematic diagram of a portion of a drilling assembly that includes a cutting device for cutting the core while drilling and a plurality of sensors for taking measurements relating to one or more parameters or properties of the core and the formation according to one embodiment of the disclosure;

15 **FIG. 2A** is a schematic diagram of a portion of a drilling assembly that shows a nuclear magnetic resonance (NMR) sensor disposed around a nonmagnetic portion of a core barrel for taking NMR measurements of the core according to one embodiment of the disclosure;

FIG. 2B is a schematic diagram of a portion of a drilling assembly that shows a
20 removable sensor package around a core for taking measurements of one or more properties of the core and/or the formation according to one embodiment of the disclosure;

FIG. 2C is a schematic diagram showing placement of acoustic transmitters and receivers for taking acoustic measurement relating to a core according to one embodiment
25 of the disclosure;

FIG. 3 is a schematic diagram of a portion of a drilling assembly that includes a storage chamber for storing one or more core samples for retrieval to the surface during or after drilling of the wellbore;

FIG. 4 is a schematic diagram of a portion of a drilling assembly that shows a
5 method of selectively storing core samples in a sample chamber above a core cutting device;

FIG. 5 is a schematic diagram of a portion of a drilling assembly showing a manner of continuing to perform coring and core analysis after a selected sample has been stored in the core sample chamber shown in **FIG. 4**;

10 **FIG. 6** (comprising **FIGS. 6A, 6B** and **6C**) shows a sequence of collecting multiple core samples according to one aspect of the disclosure; and

FIG. 7 shows an exemplary functional block diagram of controllers in the system of **FIG. 1** for controlling the coring and core analysis functions according to one aspect of the disclosure.

DETAILED DESCRIPTION OF THE EMBODIMENTS

[0010] FIG. 1 (comprising FIGS. 1A and FIG. 1B) is a schematic diagram showing an exemplary drilling system 100 that may be utilized for continuous coring, selectively storing core samples, estimating one or more properties of the core and/or estimating formation parameters during drilling of a wellbore 110 according to one aspect of the disclosure. FIG. 1 shows a wellbore 110 being drilled with a drill string 112 in a formation 101. The drill string 112, in one aspect, includes a tubular member 114 and a drilling assembly 120, also referred to as a “bottomhole assembly” or “BHA” attached at its bottom end 118 with a suitable connection joint 116. The tubular member 114 is typically made up by connecting drill pipe sections. A drill bit 150 (also referred to herein as the “coring bit”) is attached to the bottom end 121 of the drilling assembly 120 for drilling the wellbore 110 in the formation 101. The drill bit 150 has a through bore or mouth 152 having a diameter substantially equal to the diameter of the core 130 to be obtained. The drill bit 150 is attached to a drill collar 122 of the drilling assembly 120. The drill collar includes an internal barrel or liner 124 for receiving the core 130 therein. The barrel 124 remains stationary when the drilling assembly 120 is rotated to rotate the drill bit 150 to obtain the core 130. Suitable centralizers or support members 125, such as stabilizers, bearings assemblies, etc. may be placed at selected locations between the core barrel 124 and an inside wall 128 of the drilling assembly 120 to provide lateral or radial support to the core barrel 124.

[0011] In one aspect, a cutting device (or cutter) 140 may be placed at a selected distance above or uphole the drill bit mouth 152 to cut or disintegrate the core 130 after it has been received in the barrel 124. In one aspect, the cutting device 140 may be configured to grind the top end of the core 130. In another aspect, the cutting device 140 may be configured to cut the core from the core sides. In yet another aspect, the cutting device 140 may be configured to selectively engage the core 130 to cut the core. In another aspect the cutting device 140 may be configured to retract or disengage from the

core **130** so that a portion of the core **130** may be moved into a core storage or sample chamber **126** above or uphole of the barrel **124** as described in more detail later in reference to **FIGS. 2-5**. In one aspect, the cutting device **140** may be configured to continuously remove or cut the top end of the core **130** to enable the core barrel **124** to

5 continuously receive the core **130** as it is extracted from the formation **101**. This method allows continuous coring beyond the length of the core barrel **124**. A power unit **132** provides power to the cutting device **140**. In the configuration shown in **FIG. 1B**, the cutting device **140** cuts or removes the top end of the core **130** at or above the rate of penetration (ROP) of the drill bit **150** into the formation **101**. The cutting device **140** may

10 be any suitable device that can cut the core at the desired rates, including, but not limited to, a mechanical cutter with blades, one or more side drill bits, a cutting device that utilizes high pressure fluid (liquid or gas or a mixture), an explosive device and a laser device. The power unit **132** for a mechanical cutter with blades may be any suitable device, including, but not limited to, an electrical motor, a fluid-operated motor, and a

15 pneumatic motor. A fluid cutting device may include one or more stages for building fluid pressure downhole and the high pressure fluid so generated may be applied to the core **130** via one or more nozzles or jets placed around the barrel **124**. A downhole controller or control unit **180** in the drilling assembly **120** may control the operation of the cutting device **140**. The controller **180**, in one aspect, may include a processor, such

20 as microprocessor, one or more data storage devices (or memory devices) and other circuitry configured to control the operation of the cutting device **140** according to programmed instructions stored in the memory device in the control unit **180** or instructions supplied from the surface. The operation of the cutting device **140** is described in more detail later in reference to **FIGS. 2-6**.

25 **[0012]** The storage barrel or chamber **126** is placed above the cutting device **140** to receive the core **130**. Multiple cores **126a**, **126b**, **126c** may be stored in the chamber **126**, each such core being separated by a separator, such as separators **126a'** and **126b'** as

described in reference to **FIGS. 6A** and **6B**. A retrieval device **129** placed above the core storage chamber **126** may be provided to retrieve the cores from the chamber **126** via a suitable mechanism **139**, such as a wireline, slick line, etc. Such retrieval devices and methods are known in the art and are thus not described in detail herein. The storage chamber **126** may, however, also be used to retain the one or more core samples during drilling, which samples may then be retrieved for analysis after the drilling assembly **120** is tripped out of the wellbore.

[0013] The drilling assembly **120** further may include a variety of sensors and devices, generally designated herein by numeral **160**, for taking measurements relating to one or more properties or characteristics of the: (i) core **130**; (ii) fluid in the wellbore; and (iii) formation **101**. The processor in the controller **180** in the drilling assembly **120** and/or the processor in the surface control unit **40** may be configured to perform tomography of the core **130** using the sensor measurements. For the purpose of this disclosure, the term tomography is used in a broad sense to mean imaging of a parameter or characteristic in two or three dimensions. A device used in tomography may be referred to as a tomograph and the image produced as a tomogram. As described later, some of the devices **160** may be utilized to perform measurements on the core **130**, as shown by inward arrows **162**, some other devices may be used to perform measurements on the formation **101** as shown by the outward arrows **164**, while some other devices may be used to perform measurements on the fluid in the wellbore. Additionally, the drilling assembly **120** may include sensors **166** for determining the inclination, position and azimuth of the drilling assembly **120** during drilling of the wellbore **110**. Such sensors may include multi-axis inclinometers, magnetometers and gyroscopic devices. The information obtained from sensors **166** may be utilized for drilling the wellbore **110** along a selected wellbore trajectory. The controller **180** also may control the operation of one or more devices **160** and **166**. Individual devices may contain their own controllers. A telemetry unit **170** in the drilling assembly **120** communicates with the downhole devices **160** and **166** via a link,

such as a data and power bus **174**, and establishes a two-way communication between such devices and the surface controller **40**. Any suitable telemetry system may be utilized for the purpose of this disclosure, including, but not limited to, a mud pulse telemetry system, an electromagnetic telemetry system, an acoustic telemetry system, and wired pipe system. The wired-pipe telemetry system may include jointed drill pipe sections which are fitted with a data communication link, such as an electrical conductor or optical fiber. The data may also be wirelessly transmitted using electromagnetic transmitters and receivers across pipe joints or acoustic transmitters and receivers across pipe joints.

[0014] The drill string **112** extends to a rig **10** (**FIG. 1A**) at the surface **16**. The rig **10** includes a derrick **11** erected on a floor **12** that supports a rotary table **14** that is rotated by a prime mover, such as an electric motor (not shown), at a desired rotational speed to rotate the drill string **112** and thus the bit **150**. The drill string **112** is coupled to a drawworks **30** via a Kelly joint **21**, swivel **28** and line **29**. During drilling operations, the drawworks **30** is operated to control the weight on bit, which affects the rate of penetration. The operation of the drawworks **30** is known in the art and is thus not described in detail herein. During drilling operations a suitable drilling fluid **31** (also referred to as the “mud”) from a source or mud pit **32** is circulated under pressure through the drill string **112** by a mud pump **34**. The drilling fluid **31** passes into the drill string **112** via a desurger **36** and a fluid line **38**. The drilling fluid **31** discharges at the borehole bottom **151**. The drilling fluid **31** circulates uphole through the annular space **127** between the drill string **112** and the borehole **110** and returns to the mud pit **32** via a return line **35**. A sensor **S1** in the line **38** provides information about the fluid flow rate. A surface torque sensor **S2** and a sensor **S3** associated with the drill string **20** respectively provide information about the torque and the rotational speed of the drill string. Additionally, one or more sensors (not shown) associated with line **29** are used to provide data regarding the hook load of the drill string **112** and about other desired parameters relating to the drilling of the wellbore **110**.

[0015] The surface control unit **40** may receive signals from the downhole sensors and devices via a sensor **43** placed in the fluid line **38** as well as from sensors **S1**, **S2**, **S3**, hook load sensors and any other sensors used in the system. The processor **40** processes such signals according to programmed instructions and displays desired drilling parameters and other information on a display/monitor **42** for use by an operator at the rig site to control the drilling operations. The surface control unit **40** may be a computer-based system that may include a processor **40a**, memory **40b** for storing data, computer programs, models and algorithms **40c** accessible to the processor **40a** in the computer, a recorder, such as tape unit for recording data and other peripherals. The surface control unit **40** also may include simulation models for use by the computer to process data according to programmed instructions. The control unit responds to user commands entered through a suitable device, such as a keyboard. The control unit **40** is adapted to activate alarms **44** when certain unsafe or undesirable operating conditions occur.

[0016] **FIG. 2** is a simplified schematic diagram **200** of a portion **220** of the drilling assembly **120** that may be utilized for, among other things, performing continuous coring, continuous tomography of the core, continuous formation evaluation, and/or in-situ calibration of one or more downhole sensors. **FIG. 2** shows the core **130** being received in the core barrel **124** and a cutting device **140** mounted above or adjacent to a top end **226** of the core barrel **124**. In this configuration, as the wellbore **110** is drilled, the core **130** is received in the barrel **124**. When the core **130** reaches the top end **226** of the core barrel, the cutting device **140** starts to disintegrate a top portion of the core **130**, thereby allowing the new or additional core to enter into the core barrel **124** as the drilling continues. The cutter is configured or operated to remove the top end of the core at a rate that is the same or greater than the rate of penetration of the drill bit **150** for continuous coring operations. This allows the core to be received into the core barrel continuously without the need to stop drilling the wellbore **110**, thereby allowing continuous coring operations. In one aspect, suitable openings **228** may be provided in the drill collar **122** to

discharge the core cuttings into the wellbore **110**. In another aspect, fluid **242** under pressure may be discharged on the core cuttings or the cutting device **140** and/or at or near the top of the core **130** to lubricate the blades of a mechanical cutting device and to force the core cuttings out of the area in which the cutting operation is being carried on and into the wellbore or into a channel made in the drill collar **112**. Any suitable nozzle **244** attached to fluid source (such as source **132**, **FIG. 1B**) may be utilized to supply the fluid **242**. The controller **180** may control the cutting rate of the cutting device **140** and the supply of the fluid **242**. In another aspect, the cutting device **140** may be configured to alter the cutting rate based on the ROP of the drill bit **150**. In another aspect, the cutting rate of the cutting device may be set sufficiently high to ensure cutting of the core at or above the maximum ROP of the drill bit **150**.

[0017] Referring to **FIGS. 1** and **2**, the drilling assembly **120** may be configured to include any number of sensors **160** for estimating one or more properties of interest downhole. As an example, a resistivity sensor **262a** may be provided to measure an electrical property of the core **130**. The resistivity sensor **262a** may contain electrodes that induce electrical current along a periphery of the core **130** for obtaining a resistivity property of the core and for providing a tomogram thereof. The resistivity sensor may also be an electromagnetic wave propagation device, such as an induction device, to estimate an electrical property of the core, such as impedance, water saturation, etc. Different frequencies may be utilized to investigate different depths of the core **130**. Typically, the core diameter is relatively small (5-15 cm) and the analysis by resistivity sensors can provide a three dimensional picture of the properties of interest. In another aspect, a resistivity device **262b** may be provided to estimate the electrical properties of the formation **101** surrounding the core **130**. The sensors **262a** and **262b** may be configured to measure the same properties for the core **130** and the formation **101**. In one aspect, the values from the sensors **262a** and **262b** may be compared and the difference or variance between the two sets of values may be utilized for in-situ calibration of one or

both sensors. Thus, the configuration shown **FIG. 2** allows continuous coring; enables continuous estimation or determination of one or more properties of the core; enables performing continuous tomography of the core; provides estimates of the same properties of the core and the formation; and allows in-situ calibration of one sensor based on the
5 measurements of another sensor.

[0018] In another aspect, an acoustic sensor or device **264a** may be used to measure one or more acoustic properties of the core **130** and another acoustic sensor **264b** may be used to measure the same and/or different properties of the formation surrounding the core. Acoustic sensors may be utilized to: image the outside of the core **130** and the inside of
10 the wellbore; estimate acoustic porosity of the core and the formation **101**; estimate acoustic travel time, etc. In another aspect a nuclear magnetic resonance (“NMR”) device **266a** may be utilized to estimate permeability and other rock properties of the core **130** and another NMR device **266b** may be utilized to estimate permeability and other rock properties of the formation **101**. Thus, any suitable device or sensor may be utilized to
15 estimate properties and/or tomography of the core. Additionally any suitable sensor may be used to estimate properties of interest of the formation **101**. In addition to the devices noted above, drilling assembly **120** may include: sensors to estimate pore saturation, pore pressure, wettability, internal structure of the core; optical devices, including spectrometers, for determining fluid properties and/or fluid composition (such as
20 proportions of oil, gas, water, mud contamination, etc.), absorbance, refractive index, and presence of certain chemicals; laser devices; nuclear devices; x-ray devices, etc. The sensors **160** may also include nuclear sensors (neutron and chemical source based sensors), pressure sensors, temperature sensors, gamma ray and x-ray sensors. The measurements made by such sensors may be processed alone or combined to provide
25 estimates of desired properties of interest, including, but not limited to, tomography, porosity, permeability, bulk density, formation damage, pore pressure, internal structure, saturation, capillary pressure, an electrical property, acoustic properties, geomechanics,

and density. The sensors used to obtain properties of interest of the core, such as sensors **262a**, **264a**, **266a**, etc., are also referred to herein as the tomography-while-drilling (TWD) sensors and the sensors used to estimate properties of the formation or wellbore fluids, such as sensors **262b**, **264b**, **266b**, etc., are also referred to herein as the measurement-while-drilling (MWD) sensors or logging-while-drilling (LWD) sensors.

[0019] FIG. 2A is a schematic diagram of a portion **201** of the drilling assembly that shows one exemplary configuration of an NMR sensor **270** placed in the drilling assembly **120** for taking NMR measurements of the core **130**. In this configuration, the core barrel **124** includes a non-conductive segment **124a** to allow the NMR signals to penetrate into the core. The non-conductive segment **124a** may be made from any suitable material, such as an aramid fiber. The NMR sensor **270** is shown to include a magnet **272** that surrounds the core **130** to induce a constant magnetic field in the core **130**. A transmitter circuit **274** transmits a radio frequency magnetic field into the core **130** via a transceiver coil **276** disposed on one side of the core. The transceiver coil also receives the return signals from the core **130**. A processing circuit **280** preprocesses the signals received by the transceiver coil and provides digital signals to the downhole controller **180** for further processing. The digital signals may be processed by the downhole controller **180** and/or the surface controller **40** to estimate properties of the core. The NMR sensor **270** may include a gradient coil assembly **278** controlled by a gradient driving circuit **275**. The gradient coil assembly **278** and the driving circuit are configured to facilitate MRI (magneto-resonance imaging) at least in one dimension. The NMR sensor **270** may be provided alone or in addition to another NMR sensor that provides similar measurements for the formation **101**. One of these sensors may be used to calibrate the other sensor.

[0020] FIG. 2B is a schematic diagram of a portion **202** of the drilling assembly **120** that shows an exemplary configuration of a removable sensor module **281** that may include one or more sensors for estimating one or more properties of the core **130** and/or

the formation **101** surrounding the core **130**. In this configuration, there is provided a gap **282** between the core barrel **124** and an inside **283** of the drill collar **122** that is sufficient to accommodate the removable sensor module **281**. The sensor module **281** may include any suitable sensor, including any of the sensors discussed herein above. Also, one or more sensors **285** may be provided proximate to the drill bit **150** to obtain measurements of one or more parameters of the formation in front of the drill bit **150**. Such sensors are referred to as look-ahead sensors and may include, but are not limited to, a resistivity sensor, an acoustic sensor and a gamma ray sensor. Such sensors also provide information about the formation type, such as sand and shale. Additionally, any suitable sensors **287** may be disposed in the drill bit **150** for providing measurements relating to properties of the drill bit **150**, core **130** and/or the formation **101**. The resistivity sensor is configured so that an electrical loop **288** is created about the drill bit **150**.

[0021] FIG. 2C shows acoustic sensor arrangements **290** for estimating acoustic properties of the core **130**. In one aspect, a first acoustic transmitter **291** may be used to induce acoustic waves in to the core **130** and a receiver **292** placed radially from the transmitter **291** receives the acoustic waves passing through the core **130** for measuring horizontal acoustic velocity. In another aspect a receiver **293** may be placed axially from the transmitter **291** for estimating the vertical acoustic velocity. In another aspect a receiver **294** may be placed axially from the receiver **292**. A single transmitter and a single receiver either axially or radially disposed enable estimating formation slowness in the axial or radial plane either individually or at the same time with multiple receivers. In another aspect additional transmitters and receivers may be placed around the core to estimate azimuthal properties of the core **130**. Thus, in aspects, one or more acoustic transmitters may be disposed axially, azimuthally or both with one or more receivers placed axially, azimuthally or both around the core for estimating various acoustic properties of the core. The azimuthal measurements may be made by azimuthally arranging transmitter-receives around a radial plane. Additionally, acoustic sensors may

be arranged to make measurements at selected angles between the axial planes. Such measurements may be used to improve or refine the acoustic formation parameters or to enhance arrival times of one set of acoustic signals over another set of acoustic signals. In another aspect an acoustic sensor may be placed in contact with the core **130**, such as through an opening in the chamber **124**, to estimate the acoustic impedance of the core by evaluating the loading applied on the acoustic transmitter. The acoustic signals from the receivers may be processed by the downhole control unit **180** and/or the surface control unit **40**. The downhole processed data may be stored in a memory that may be retrieved to the surface during drilling.

10 **[0022]** FIGS. 3 and 4 are schematic diagrams of a portion **300** of a drilling assembly **120** that includes a storage chamber for storing one or more core samples for retrieval during or after drilling of the wellbore. The configurations of the drilling assembly portion **300** shown in FIGS. 3 and 4 are the same, each including a core storage chamber **324** above the cutting device **140**. FIG. 3 illustrates the cutting device **140** in a retracted position to allow the core **130** to enter into the core storage chamber **324**. A sensor **426** may be provided to determine the length of the core **424** in the chamber **324**. Once a desired core length has been stored in the chamber **324**, the controller **180** (FIG. 1A) may cause the cutting device **140** to engage the core **130** and cut the core sample **424** radially from the remaining core, which allows the core chamber **324** to store the core sample **424** therein. As shown in FIG. 5, once the core sample **424** has been stored, the cutting device **140** may be engaged with the core **130** to continue to cut the top portion of core **130**, which allows further continuous coring and the interrogation and analysis of the core and formation properties as described above in reference to FIGS. 1, 2, 2A, 2B and 2C.

25 **[0023]** Additional core samples may be stored in the sample chamber **324** by stopping the cutting device **140** and moving it away from the core barrel to allow the next core sample to enter into the core storage chamber **324**. In this manner selected core samples (corresponding to different wellbore depths) may be stored in the chamber **324**. The core

sample stored in the chamber **324** may be retrieved to the surface by the retrieval device **129** (**FIG. 1B**).

[0024] **FIG. 6A** is a schematic diagram showing the placement of a spacer between the core samples in chamber **324**. In one aspect, to identify the location in the wellbore from which a particular sample has been extracted, a spacer **610a** may be inserted below the first core sample **424a** after it is cut and stored in the chamber **324**. Prior to storing a second sample, the cutting device is disengaged from the core **130**, which allows the second sample **424b** to move into the chamber **324** below the first spacer **610b**, as shown in **FIG. 6B**. The second core sample **424b** is then cut by engaging the cutter **140**. A second spacer **610b** may then be placed below the second sample **424b**. Additional core samples from different wellbore depths may be stored in the manner described above. The above-described system allows for storing multiple samples from different depths without the removal of a core sample or tripping out the drill string **118**. In one aspect, the core storage chamber **324** may be lined with a sponge liner **620**, as shown in **FIG. 6C**. Oil trapped in the core **424a**, **424b**, etc. escapes from the core during tripping of the core out of the wellbore **110** and is absorbed by the sponge liner **620**.

[0025] **FIG. 7** shows a functional block diagram **700** of a system that may be utilized for controlling the coring operation and estimating the various desired properties of the core and formation. In one aspect, the downhole controller **180** may control the operation of the cutting device power unit **142** to control the cutting operations of the cutting device **140** according to programmed instructions **784** stored in a downhole storage device **782** and/or instructions received from the surface controller **40** via a surface telemetry units **772** and the downhole telemetry unit **170**. The downhole controller **180** also may control the operation of the tomography-while-drilling (TWD) sensors **710** (such as sensors **262a**, **264a** and **266a** (**FIG. 1B**) and MWD/LWD sensors **720**, such as sensors **262b**, **264b** and **266b** via a bus **712** according to programs and models stored in the storage device **782** and/or instructions received from the surface controller **40**. The downhole controller **180**

also may control other downhole sensors **730** in the manner similar to that utilized to control the TWD and MWD/LWD sensors. The downhole controller **180** or surface controller **40** or a combination thereof may process the measurement data obtained from one or more downhole sensors to provide estimates of the various desired properties of the core **130** and the formation **101** and generate two-dimensional or three-dimensional continuous representations of one or more of such properties. The results so generated may be stored in the storage device **782** and/or at the surface storage device **742**. Also, some or all of the data processing may be performed by a remote controller in-situ or at a later time.

10 **[0026]** Thus, in one aspect, a continuous coring method is provided that may include: drilling into a formation to retrieve a core; receiving the core into a chamber at an open end of a chamber; and removing or cutting a portion of the core uphole of the open end of the chamber to allow the chamber to continue to receive the core at the open end as drilling into the formation continues. Removing the portion of the core may be
15 accomplished by any suitable method, including using a mechanical cutting device, such as a side drill bit or mechanical cutting blades, pressurized fluid, a laser cutting device, etc. The method may further include: stopping coring at a first wellbore depth; continuing to drill into the formation to a second depth; removing an end of the core so as to continue to receive additional core into the chamber at the second depth. The method may further
20 include using a sensor to take one or more measurements downhole for estimating a property of interest of the core. The method may further comprise providing a three dimensional map or model of one or more properties of the core. The method may further comprise using a sensor to take a measurements downhole for estimating a property of interest of the formation. The property of interest for the core may be the same or
25 different from the property of interest of the formation.

[0027] In another aspect, a coring apparatus is provided that includes: a coring bit for drilling into a formation to retrieve a core; a core barrel uphole of the coring bit for

receiving the core therein; a cutting device uphole of the drill bit for cutting or disintegrating a portion of the core at an upper end of the core so that the core barrel may continuously receive the core as the coring bit continues to retrieve the core from the formation. In one aspect, the core barrel is contained within a drilling assembly attached to a bottom end of a drilling tubular. The cutting device may be any suitable device, including, but not limited to, a mechanical cutting device, such as a metallic blades or a side cutting bit, a device that injects high pressure fluid onto the core to cut the core, and a laser device. A power unit provides the power to the cutting device. In one aspect, the apparatus allows continuous coring without the need to store long core samples or the need to retrieve core from the drill sting during drilling of a wellbore.

[0028] The apparatus may further include a controller that controls the cutting device. In one aspect, the controller maintains the cutting rate of the core at or greater than the rate of penetration of the coring bit. In another aspect, the cutting device may be set to cut the core at a rate that is equal to or greater than a selected drilling rate of penetration.

[0029] In another aspect, an NMR sensor used for estimating an NMR parameter of the core may include: a magnet configured to induce a substantially constant magnetic field in the core; a transmitter coil between the core and the magnet configured to induce an electrical signals into the core at a selected frequency; and a receiver coil spaced apart from the transmitter coil for receiving signals from the core responsive to the induced signals. The magnet and coil may be placed proximate to a non-conductive member between the core and NMR sensor. In another aspect, an NMR sensor used for estimating an NMR parameter of the formation surrounding the core may include: a pair of spaced-apart magnets configured to induce a substantially constant magnetic field in a region of interest of the formation; a transmitter coil configured to induce electrical signals into the region of interest at a selected frequency; and a receiver coil configured to receive signals responsive to the transmitted electrical signals.

[0030] In another aspect, an acoustic sensor used for estimating a property of the core may include: at least one transmitter configured to induce acoustic signals into the core, and at least one receiver spaced apart from the at least one transmitter configured to receive acoustic signals from the core that are responsive to the transmitted acoustic signals. The at least one receiver may comprise a first receiver placed radially spaced from the at least one transmitter for estimating an acoustic velocity through the core and a second receiver placed axially from the at least one transmitter for estimating an axial acoustic velocity of the core. An acoustic sensor for estimating a property of the formation may include at least one transmitter configured to transmit acoustic signals into the formation and at least one receiver configured to receive acoustic signals responsive to the transmitted acoustic signals into the formation and wherein the processor provides an estimate of an acoustic property of the formation based on the received acoustic signals. In another aspect, an acoustic sensor may be configured to contact the core for estimating an acoustic impedance of the core. In another aspect, any sensor may be placed proximate to a drill bit attached to a bottom end of the bottomhole assembly for providing signals for estimating one or more properties of the formation ahead of the drill bit. In one aspect, the formation type, such as shale or sand may be determined by the sensors in the drill bit.

[0031] In another aspect, any of the sensors may be housed in a removable package placed proximate to the core. The removable sensor package may include any suitable sensor, including, but not limited to: (i) an electrical sensor; (ii) an acoustic sensor; (iii) a nuclear sensor; (iv) a nuclear magnetic resonance sensor; (v) a pressure sensor; (vi) an x-ray sensor; and (vii) a sensor for estimating one of a physical property and a chemical property of the core.

[0032] In another aspect, a method for estimating a property of interest downhole may include: receiving a core at a receiving end of a downhole tool while removing a portion of the received core distal from the receiving end of the downhole tool; inducing a

substantially constant magnetic field in the core; transmitting electrical signals into the core at a selected frequency by a coil placed between the core and the magnet; receiving signals responsive to the transmitted electrical signals from the core; and processing the received signals to provide an estimate of a property of interest of the core. In another aspect, a method for estimating a property of interest may include: transmitting a current field into the core through a one of a magnetic, galvanic, and capacitive coupling; receiving signals responsive to the transmitted current field from the core through one of the magnetic, galvanic and capacitive coupling; and processing the received signals to provide an estimate of a property of interest. In another aspect, a method may include: transmitting acoustic signals into the core during continuous coring; receiving acoustic signals responsive to the transmitted acoustic signals from the core; and processing the received signals to provide an estimate of a property of the core. In one aspect, the acoustic sensor may include at least a portion that contacts the core for estimating an acoustic impedance of the core. The property of interest may include one or more of: (i) porosity; (ii) permeability; (iii) dielectric constant; (iv) resistivity; (v) a nuclear magnetic resonance parameters; (vi) an oil-water ratio; (vii) an oil-gas ratio; (viii) a gas-water ratio; (ix) a composition of the core or formation; (x) pressure; (xi) temperature; (xii) wettability; (xiii) bulk density; (xiv) acoustic impedance; (xv) acoustic travel time; and (xvi) a mechanical parameter. The sensor may be one of: (i) a resistivity sensor; (ii) an acoustic sensor; (iii) a gamma ray sensor; (iv) a pressure sensor; (v) a temperature sensor; (vi) a vibration sensor; (vii) a bending moment sensor; (viii) a hardness sensor; (ix) a neutron sensor; and (x) a compressive strength sensor.

[0033] While the foregoing disclosure is directed to certain embodiments that may include certain specific elements, such embodiments and elements are shown as examples and various modifications thereto apparent to those skilled in the art may be made without departing from the concepts described and claimed herein. It is intended that all

variations within the scope of the appended claims be embraced by the foregoing disclosure.

CLAIMS

1. An apparatus for use in a wellbore, comprising:
a bottomhole assembly having a chamber configured to receive a core at an end of
5 the chamber during coring of a formation;
a cutting device configured to cut the core distal from the end of the chamber;
at least one sensor arranged proximate to the core to provide signals relating to a
property of interest during coring of the formation; and
a processor configured to provide an estimate of a property of interest based on
10 the signals.
2. The apparatus of claim 1, wherein the at least one sensor comprises a nuclear
magnetic resonance (NMR) sensor about a section of the chamber.
- 15 3. The apparatus of claim 2, wherein the NMR sensor includes:
a magnet configured to induce a substantially constant magnetic field in the core;
a transceiver coil between the core and the magnet configured to induce an
electrical signal into the core at a selected frequency and receive NMR signals
from the core; and
20 a gradient coil assembly configured to induce a gradient magnetic field in at least
one dimension to facilitate magneto-resonance imaging of the core.
4. The apparatus of claim 2 further comprising:
a magnet configured to induce a substantially constant magnetic field in a region
25 of interest of the formation;
a transmitter coil configured to induce electrical signals in the region of interest at
a selected frequency; and
a receiver coil configured to receive signals responsive to the transmitted
electrical signals;
30 wherein the processor is configured to provide an estimate of the property of
interest based on the received signals.

5. The apparatus of claim 1, wherein the at least one sensor comprises an acoustic sensor configured to provide the estimate of the property of interest.
6. The apparatus of claim 5, wherein the acoustic sensor comprises:
5 at least one transmitter configured to induce acoustic signals into the core; and
at least one receiver spaced apart from the at least one transmitter configured to receive acoustic signals from the core that are responsive to the induced acoustic signals.
- 10 7. The apparatus of claim 6, wherein the at least one receiver comprises a first receiver placed radially spaced from the at least one transmitter for estimating a first acoustic velocity of the core and a second receiver placed axially from the at least one transmitter for estimating a second acoustic velocity of the core.
- 15 8. The apparatus of claim 5, wherein the acoustic sensor includes at least one transmitter configured to transmit acoustic signals into the formation and at least one receiver configured to receive acoustic signals responsive to the transmitted acoustic signals into the formation and wherein the processor provides an estimate of an acoustic property of the formation based on the received acoustic signals.
- 20 9. The apparatus of claim 5, wherein the property of interest is an acoustic impedance and wherein the acoustic sensor is configured to contact the core through an opening in the chamber to provide signals for estimating the acoustic impedance of the core.
- 25 10. The apparatus of claim 1, wherein the at least one sensor is removable from the bottomhole assembly.
11. The apparatus of claim 10, wherein the removable sensor is at least one of: of (i)
30 an electrical sensor; (ii) an acoustic sensor; (iii) a nuclear sensor; (iv) a nuclear magnetic resonance sensor; (v) a pressure sensor; (vi) an x-ray sensor; and (vii) a sensor for estimating one of a physical property and a chemical property of the core.

12. The apparatus of claim 1, wherein the property of interest is at least one of: (i) porosity; (ii) permeability; (iii) dielectric constant; (iv) resistivity; (v) nuclear magnetic resonance parameters; (vi) an oil-water ratio; (vii) an oil-gas ratio; (viii) a gas-water ratio; (ix) a composition of the core or formation; (x) pressure; (xi) temperature; (xi) wettability; (xii) bulk density; (xiii) acoustic impedance; and (xiv) an acoustic travel time.

10

13. The apparatus of claim 1, wherein the at least one sensor includes a sensor proximate a drill bit attached to a bottom end of the bottomhole assembly for providing signals for estimating a property of the formation ahead of the drill bit.

14. The apparatus of claim 13, wherein the at least one sensor is one of: (i) a resistivity sensor; (ii) an acoustic sensor; (iii) a gamma ray sensor; (iv) a pressure sensor; (v) a temperature sensor; (vi) a vibration sensor; (vii) a bending moment sensor; (viii).a hardness sensor; (ix) a neutron sensor; and (x) a compressive strength sensor.

15

15. A method for estimating a property of interest downhole, comprising:
receiving a core at a receiving end of a downhole tool while removing a portion of the received core distal from the receiving end of the tool;
obtaining signals by a sensor downhole relating to the parameter of interest; and
processing the obtained signals to estimate the property of interest.

20

16. The method of claim 15, wherein obtaining signals comprises:
inducing a substantially constant magnetic field in the core;
transmitting electrical signals into the core at a selected frequency by a coil placed
between the core and the magnet; and
receiving signals responsive to the transmitted electrical signals from the core.

25

17. The method of claim 15, wherein obtaining signals comprises:
transmitting a current field into the core through one of a magnetic coupling, a galvanic coupling, and a capacitive coupling; and
receiving signals responsive to the transmitted current field from the core through one of the magnetic coupling, the galvanic coupling and the capacitive coupling.

30

18. The method of claim 15, wherein obtaining signals comprises:

transmitting acoustic signals into the core; and
receiving acoustic signals responsive to the transmitted acoustic signals from the
core.

5 19. The method of claim 15, wherein obtaining signals comprises contacting at least a
portion of the sensor with the core.

20. The method of claim 15, wherein the sensor is a removable sensor placed
proximate to the core.

10

21. The method of claim 15, wherein the sensor is placed at one of: (i) in a coring bit
at an end of the downhole tool; and (ii) in the downhole tool proximate to a drill bit.

22. The method of claim 15, wherein the property of interest is at least one of: (i)
15 porosity; (ii) permeability; (iii) dielectric constant; (iv) resistivity; (v) nuclear magnetic
resonance parameters; (vi) an oil-water ratio; (vii) an oil-gas ratio; (viii) a gas-water ratio;
(ix) a composition of the core or formation; (x) pressure; (xi) temperature; (xi)
wettability; (xii) bulk density; (xiii) acoustic impedance; (xiv) acoustic travel time; and
(xv) a mechanical parameter.

1/7

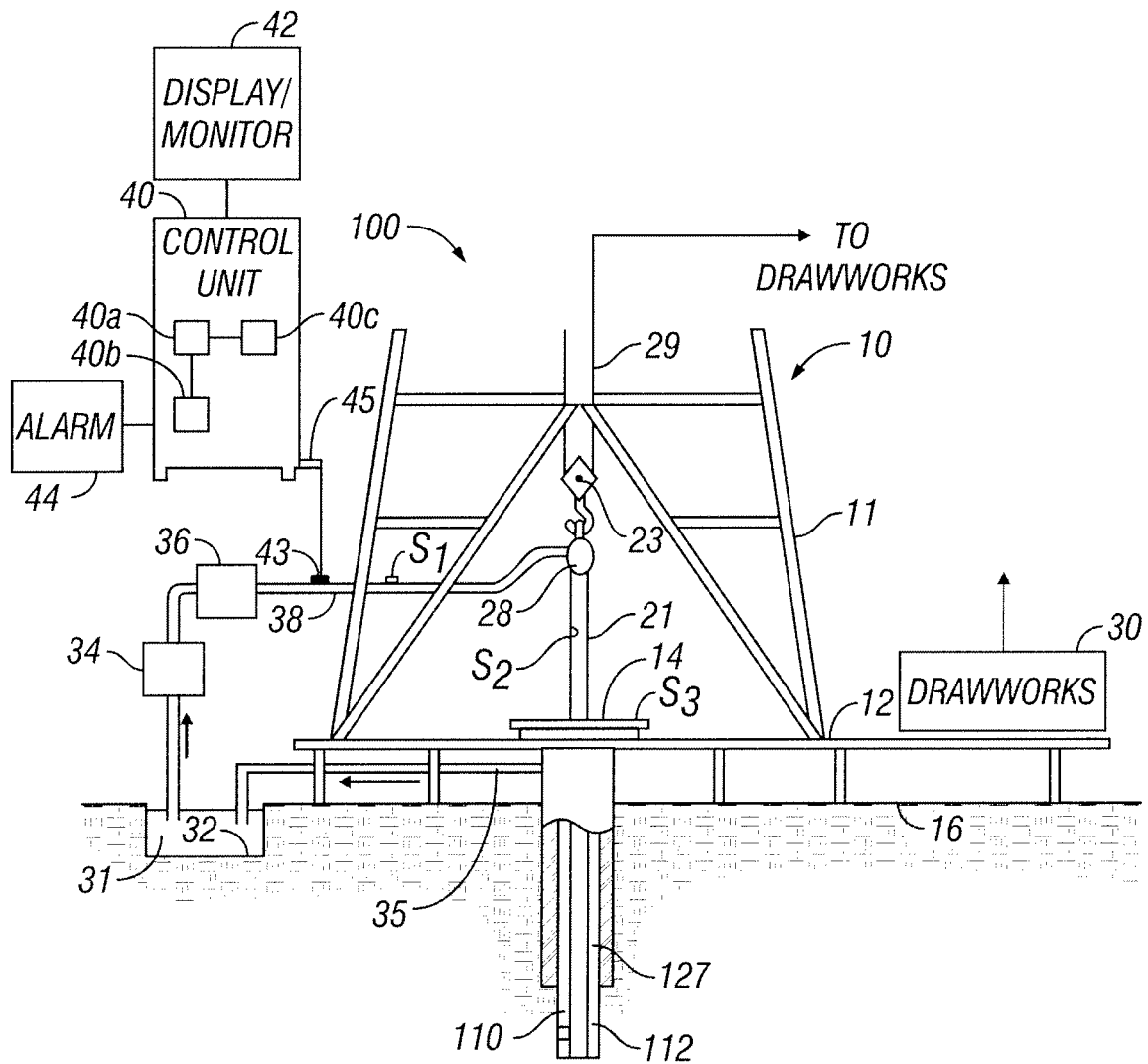


FIG. 1A

2/ 7

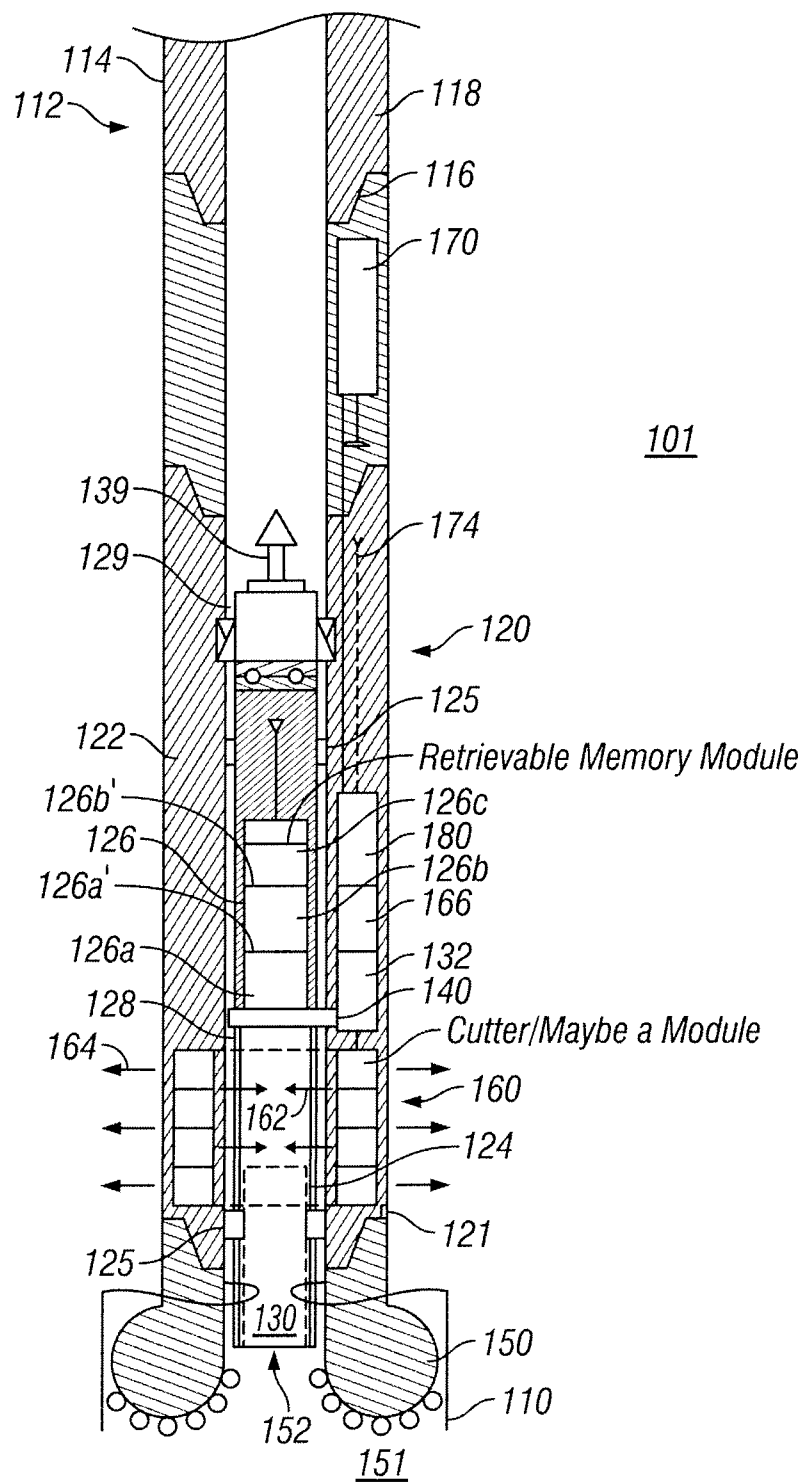


FIG. 1B

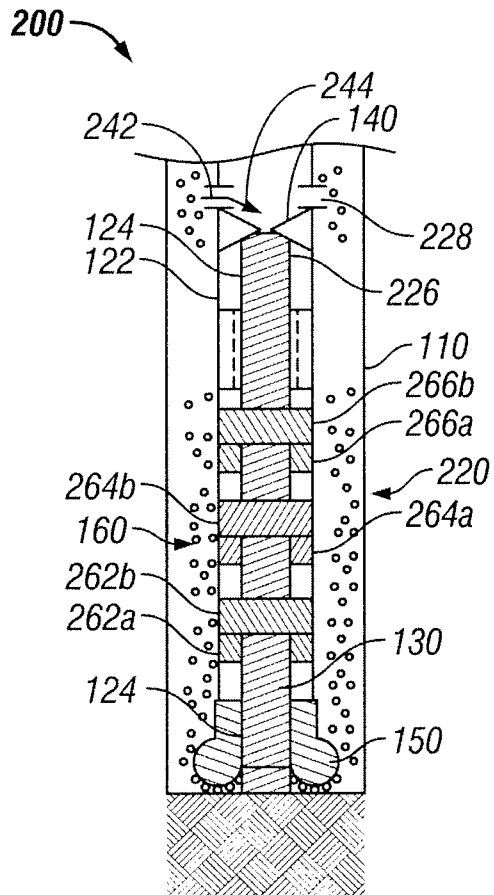


FIG. 2

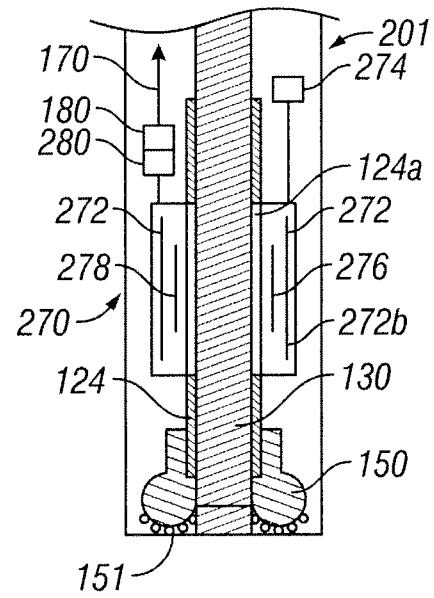


FIG. 2A

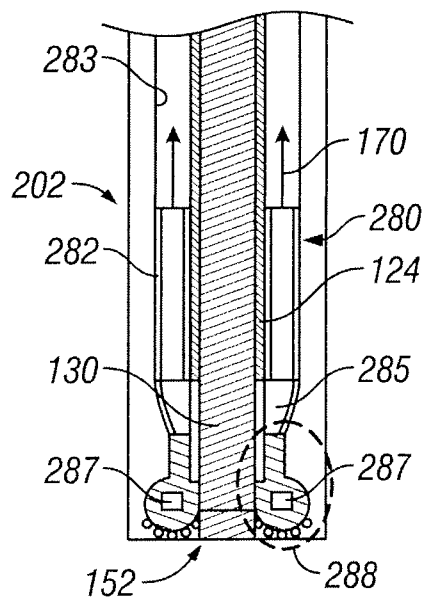


FIG. 2B

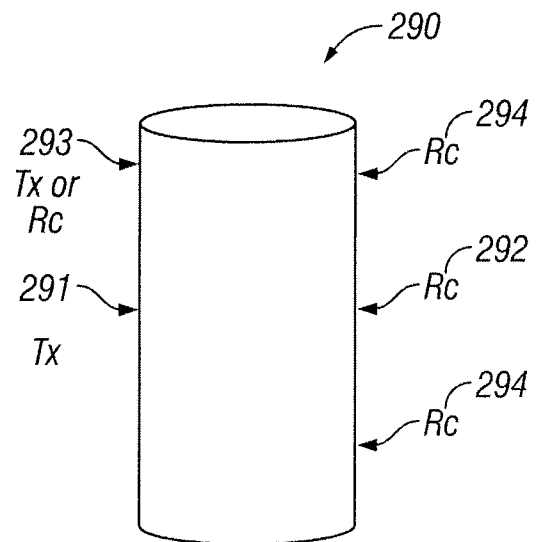


FIG. 2C

4/7

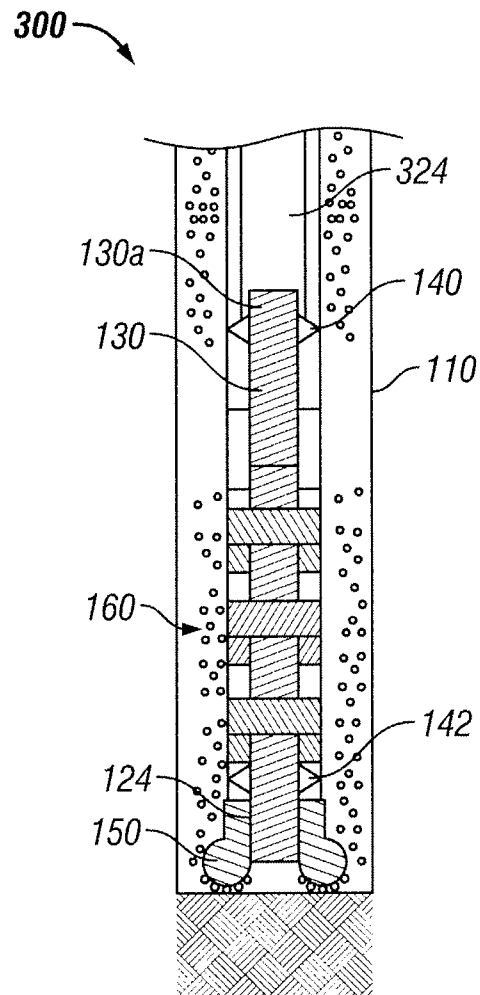


FIG. 3

5/7

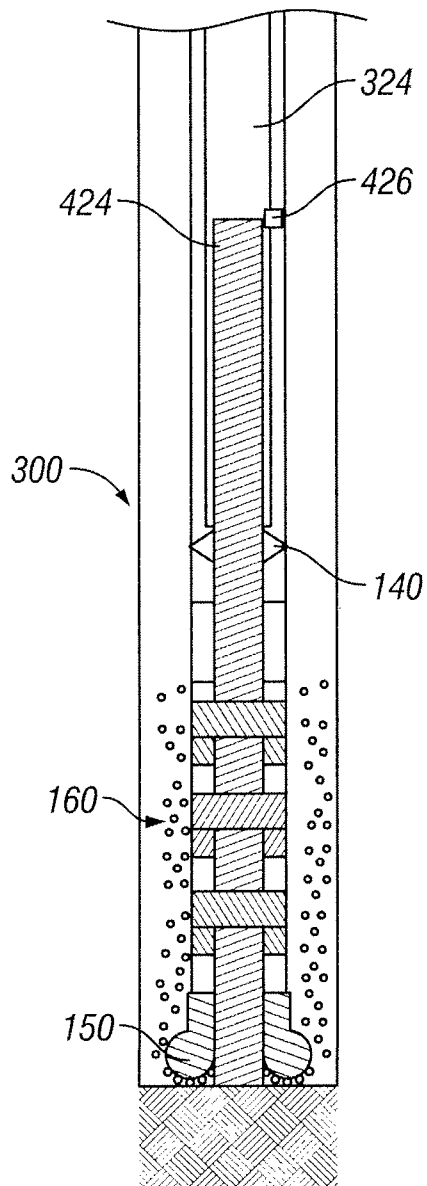


FIG. 4

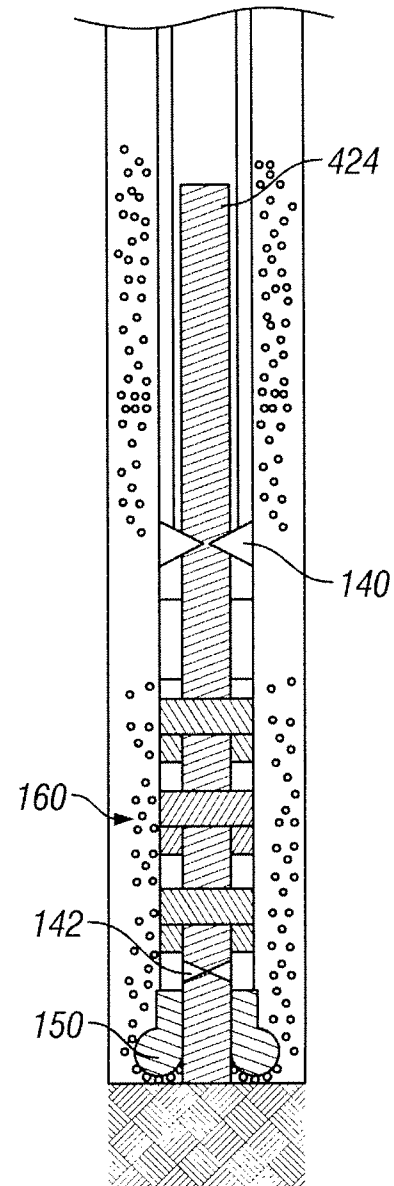


FIG. 5

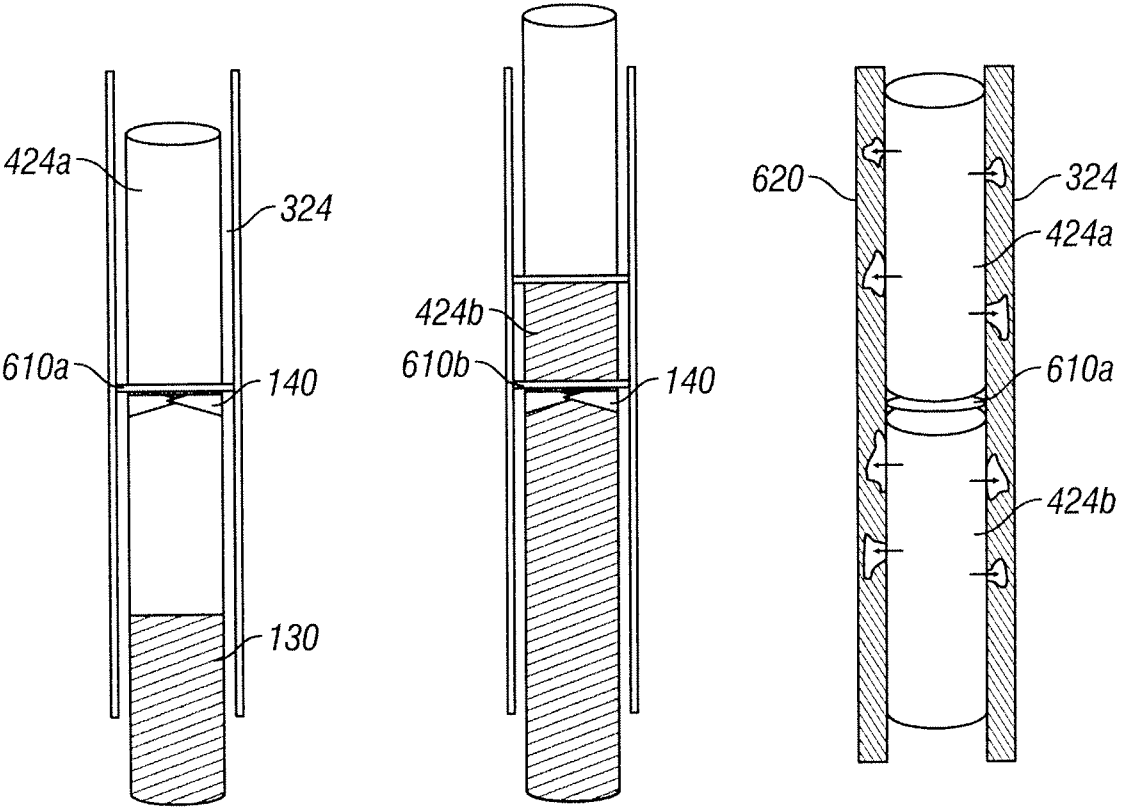


FIG. 6 A

FIG. 6 B

FIG. 6 C

7/7

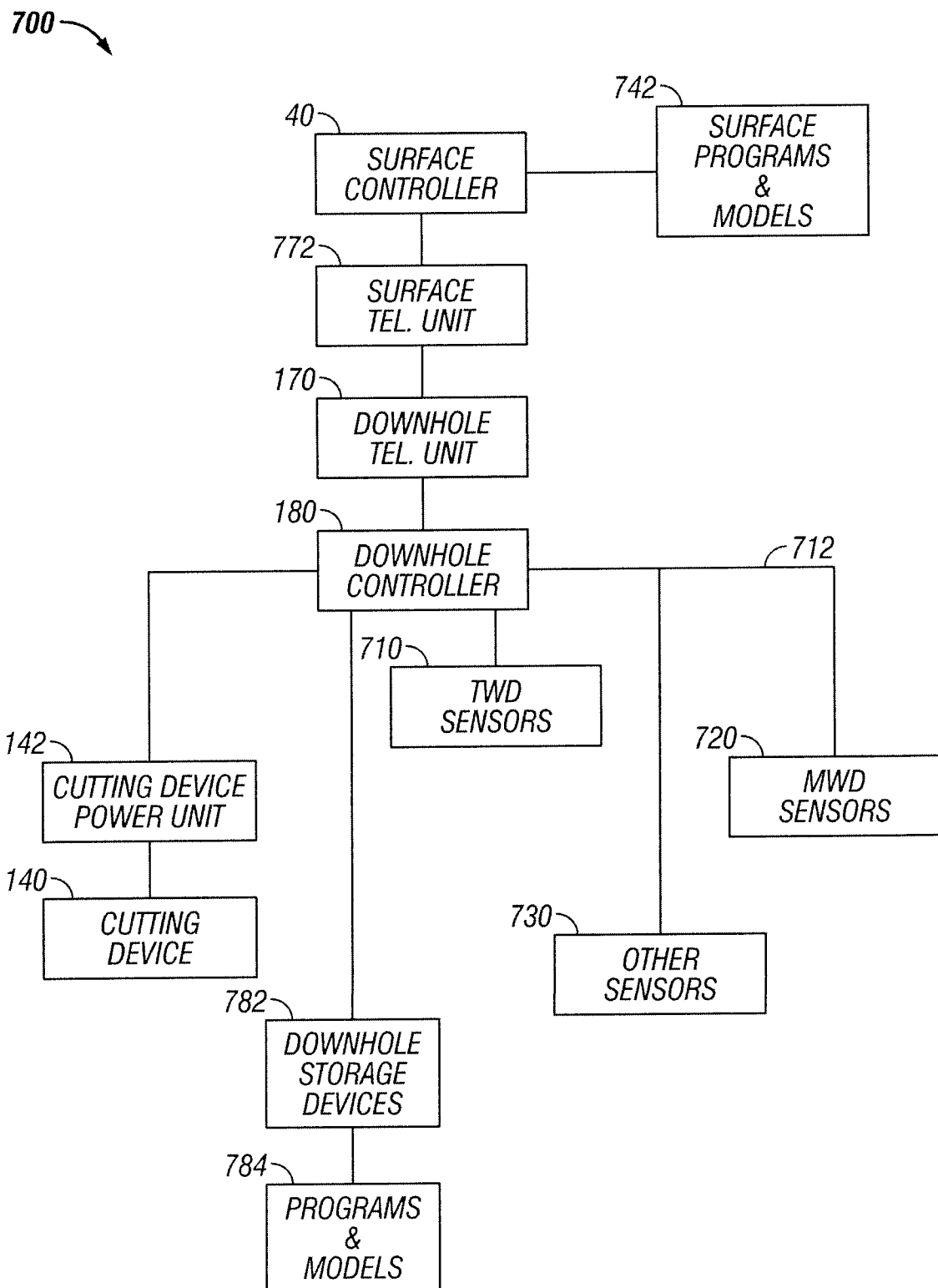


FIG. 7