

(19) World Intellectual Property
Organization
International Bureau



(43) International Publication Date
27 October 2005 (27.10.2005)

PCT

(10) International Publication Number
WO 2005/100747 A2

(51) International Patent Classification⁷: **E21B 47/01**

GILCHRIST, Allen, W. [US/US]; 20819 Augustwood Lane, Houston, TX 77073 (US). **TRCKA, Darryl, E.** [US/US]; 14301 Misty Meadow Lane, Houston, TX 77079 (US).

(21) International Application Number:
PCT/US2005/011713

(22) International Filing Date: 6 April 2005 (06.04.2005)

(74) Agents: **RIDDLE, J.** et al.; Baker Hughes Incorporated, 3900 Essex Lane, Suite 1200, Houston, TX 77027 (US).

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
10/819,665 7 April 2004 (07.04.2004) US

(71) Applicant (for all designated States except US): **BAKER HUGHES INCORPORATED** [US/US]; 3900 Essex Lane, Suite 1200, Houston, TX 77027 (US).

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

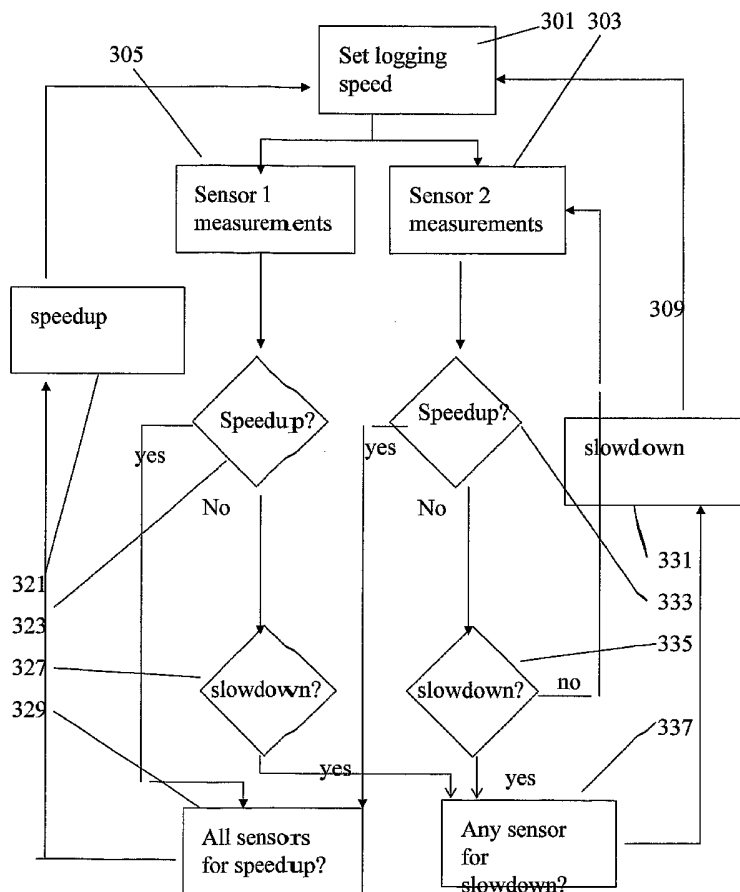
(72) Inventors; and

(75) Inventors/Applicants (for US only): **ENGELS, Ole, G.** [DE/US]; 717 Willard Street, Houston, TX 77006 (US).

(84) Designated States (unless otherwise indicated, for every kind of regional protection available): ARIPO (BW, GH,

[Continued on next page]

(54) Title: DYNAMIC LOGGING SPEED



(57) Abstract: Data from a string of multiple formation evaluation data sensor are evaluated. Based on the analysis, the logging speed is increased if all the sensors justify it, and is reduced if any of the sensors require a reduced logging speed.



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, HU, IE, IS, IT, LT, LU, MC, NL, PL, PT, RO, SE, SI, SK, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Declarations under Rule 4.17:

- as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii)) for the following designations AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BW, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NA, NI, NO, NZ, OM, PG, PH, PL, PT, RO, RU, SC, SD, SE, SG, SK, SL, SM, SY, TJ, TM, TN, TR, TT, TZ, UA, UG, UZ, VC, VN, YU, ZA,

ZM, ZW, ARIPO patent (BW, GH, GM, KE, LS, MW, MZ, NA, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HU, IE, IS, IT, LT, LU, MC, NL, PL, PT, RO, SE, SI, SK, TR), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG)

- as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii)) for all designations

Published:

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

For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

DYNAMIC LOGGING SPEED

Ole G. Engels, W. Allen Gilchrist, Darryl Trcka

Field of the Invention

5 [0001] This invention relates generally to methods of improved logging using oilfield borehole tools and more particularly to dynamic adjustment of the logging speed based on the quality of the acquired data and the formations being evaluated.

Background of the Art

10 [0002] Oil or gas wells are often surveyed to determine one or more geological, petrophysical, geophysical, and well production properties ("parameters of interest") using electronic measuring instruments conveyed into the borehole by an umbilical such as a cable, a wireline, slickline, drill pipe or coiled tubing. Tools adapted to perform such surveys are commonly referred to as formation
15 evaluation tools. These tools use electrical, acoustical, nuclear and/or magnetic energy to stimulate the formations and fluids within the borehole and measure the response of the formations and fluids. The measurements made by downhole instruments are transmitted back to the surface. In many instances, multiple trips or logging runs are needed to collect the necessary data. Additionally, the logging
20 speed is usually a predetermined fixed quantity.

[0003] In order to reduce the amount of rig time needed for wireline logging, it is common practice to run multiple sensors in a single run. FOCUSTM, from Baker Atlas Inc., is a high efficiency premium open hole
25 logging systems. (Note the grammatical error. Also, FOCUS should not be called a "premium" system, because it does not have our standard temperature and pressure rating). All of the downhole instruments have been redesigned, incorporating advanced downhole sensor technology, into shorter, lighter, more reliable logging instruments, capable of providing formation evaluation
30 measurements with the same precision and accuracy as the industry's highest quality sensors, at much higher logging speeds. Logging speeds are up to twice the speed of conventional triple-combo and quad combo logging tool strings. Speeds of upto 3600 ft/hr (1080 m/min) are possible. The logging system may

include four standard major open hole measurements (resistivity, density, neutron, acoustic) plus auxiliary services.

5 [0004] The resolution and accuracy of logging measurements is determined by the type of measurement and the type of formation being logged. The measurement may be tailored to the type of formation. For example, US Patent 5,309,098 to Coates et al. teaches a method and apparatus in which a variable time-window echo-recording system is used to obtain significant improvements in signal quality and logging speed. An initial test is performed to provide an assessment of the
10 relaxation qualities of the sample. If the test reveals that the sample is a slow-relaxation rock, then the full time is allocated to measuring echoes. However, if the test reveals that the sample is a fast decay rock, then the echo acquisition time window is reduced. This provides increased efficiency since the system is able to maximize the number of measurements made by optimizing the individual
15 sampling intervals to the particular geologic structure being tested.

[0005] Generally, prior art methods have conducted logging at a uniform logging speed. A fixed logging speed is used for the entire logging interval. This flies in the face of logic since reservoir intervals form only a small portion of the entire
20 geologic section and it is only in reservoir intervals is it necessary to get precise and accurate measurements with high resolution: in the non-reservoir intervals, high precision and accuracy are not usually necessary.

25 [0006] It would be desirable to have a method and apparatus of logging a borehole in which the inefficiencies of the prior art are overcome. Such an invention should preferably be able to accommodate a variety of logging tools. The present invention satisfies this need.

SUMMARY OF THE INVENTION

30 [0007] The present invention is a method of, and an apparatus for conducting logging operations of a borehole in an earth. A string of formation evaluation (FE) sensors are conveyed on a conveyance device such as a wireline or a slickline into the borehole. The conveyance device is operated at a logging speed

while making measurements with said FE sensors. The measurements made by said FE sensors are analyzed, and based on the analysis, a signal for alteration of the logging speed may be provided. The FE sensors are selected from the group consisting of (i) a resistivity sensor, (ii) a natural gamma ray sensor, (iii) a porosity sensor, (iv) a density sensor, (v) a nuclear magnetic resonance sensor, and, (vi) an acoustic sensor. The signal may be for either an increase or a decrease in logging speed. Based on the signal, the logging speed may be increased or decreased.

[0008] The logging speed is increased if all the FE sensors provide a valid indication that the logging speed may be increased while maintaining acceptable data quality. The logging speed is decreased if one or more of the FE sensors provide a valid indication that data quality is not acceptable at the current logging speed. The processing of the measurements may be carried out by a downhole processor, a surface processor, or in part by both a downhole processor and a surface processor.

[0009] Based on the analysis, additional sensors on the string may be activated. Correction of the measurements following an alteration of the logging speed may be done to compensate for "yo-yoing" of the wireline or slickline. The term "yo-yo" as used in the context of the present invention refers to irregular speed of the downhole logging tool even when the cable is being pulled up at the surface at a uniform speed.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] For detailed understanding of the present invention, reference should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawing and in which:

Fig. 1 (prior art) is a schematic illustration of a wireline logging system including a plurality of sensors.

Fig. 2 (prior art) is an embodiment of a system using a radially adjustable module adapted for use in logging operations;

Fig. 3 (prior art) illustrates a sectional view of one embodiment of a positioning device made in accordance with the present invention;

Fig. 4 (prior art) is a schematic elevation view of radially adjustable module positioned in an open hole portion of a borehole;

Fig. 5 is a schematic illustration of steps involved in the method of the present invention.

5

DETAILED DESCRIPTION OF THE INVENTION

[0011] The present invention is discussed with reference to specific logging instruments that may form part of a string of several logging instruments for conducting wireline logging operations. It is to be understood that the choice of the specific instruments discussed herein is not to be construed as a limitation and that the method of the present invention may also be used with other logging instruments as well.

[0012] A typical configuration of the logging system is shown in **Fig. 1**. This is a modification of an arrangement from US Patent 4,953,399 to *Fertl et al.* having the same assignee as the present invention and the contents of which are incorporated herein by reference. Shown in **Fig. 1** is a suite of logging instruments **10**, disposed within a borehole **11** penetrating an earth formation **13**, illustrated in vertical section, and coupled to equipment at the earth's surface in accordance with the method and apparatus for determining characteristics of clay-bearing formations of the present invention. Logging instrument suite **10** may include a resistivity device **12**, a natural gamma ray device **14**, and two porosity-determining devices, such as a neutron device **16** and a density device **18**. Collectively, these devices and others used in the borehole for logging operations are referred to as formation evaluation sensors. Resistivity device **12** may be one of a number of different types of instruments known to the art for measuring the electrical resistivity of formations surrounding a borehole so long as such device has a relatively deep depth of investigation. For example, a HDIL (High Definition Induction Logging) device such as that described in US Patent 5,452,761 to *Beard et al.* having the same assignee as the present invention and the contents of which are fully incorporated herein by reference may be used. Natural gamma ray device **14** may be of a type including a scintillation detector including a scintillation crystal cooperatively coupled to a photomultiplier tube such that when the crystal is impinged by gamma rays a succession of electrical

pulses is generated, such pulses having a magnitude proportional to the energy of the impinging gamma rays. Neutron device 16 may be one of several types known to the art for using the response characteristics of the formation to neutron radiation to determine formation porosity. Such a device is essentially responsive to the neutron moderating properties of the formation. Density device 18 may be a conventional gamma-gamma density instrument such as that described in US Patent 3,321,625 to *Wahl*, used to determine the bulk density of the formation. A downhole processor may be provided at a suitable location as part of the instrument suite.

[0013] Instrument suite 10 is conveyed within borehole 11 by a cable 20 containing electrical conductors (not illustrated) for communicating electrical signals between instrument suite 10 and the surface electronics, indicated generally at 22, located at the earth's surface. Logging devices 12, 14, 16 and 18 within instrument suite 10 are cooperatively coupled such that electrical signals may be communicated between each device 12, 14, 16 and 18 and surface electronics 22. Cable 20 is attached to a drum 24 at the earth's surface in a manner familiar to the art. Instrument suite 10 is caused to traverse borehole 11 by spooling cable 20 on to or off of drum 24, also in a manner familiar to the art.

[0014] Surface electronics 22 may include such electronic circuitry as is necessary to operate devices 12, 14, 16 and 18 within instrument suite 10 and to process the data therefrom. Some of the processing may be done downhole. In particular, the processing needed for making decisions on speeding up (discussed below) for slowing down the logging speed is preferably done downhole. If such processing is done downhole, then telemetry of instructions to speed up or slow down the logging could be carried out substantially in real time. This avoids potential delays that could occur if large quantities of data were to be telemetered uphole for the processing needed to make the decisions to alter the logging speed. It should be noted that with sufficiently fast communication rates, it makes no difference where the decision making is carried out. However, with present data rates available on wirelines, the decision making is preferably done downhole.

[0015] Control circuitry 26 contains such power supplies as are required for operation of the chosen embodiments of logging devices within instrument suite 10 and further contains such electronic circuitry as is necessary to process and normalize the signals from such devices 12, 14, 16 and 18 in a conventional manner to yield generally continuous records, or logs, of data pertaining to the formations surrounding borehole 11. These logs may then be electronically stored in data storage 32 prior to further processing. The processor 28 includes the ability, such as that described in US Patent 4,271,356 to *Groeschel* et al, for separating radiation measurements from natural gamma ray device 14 into individual energy bands centered about energy peaks of selected elemental sources of radiation, preferably the energy peaks of potassium, uranium and thorium. This processing of the natural gamma ray device could also be done by the downhole processor.

[0016] Surface electronics 22 may also include such equipment as will facilitate machine implementation of the method of the present invention. Processor 28 may be of various forms but preferably is an appropriate digital computer programmed to process data from logging devices 12, 14, 16 and 18. Memory unit 30 and data storage unit 32 are each of a type to cooperatively interface with processor 28 and/or control circuitry 26. Depth controller 34 determines the longitudinal movement of instrument suite 20 with borehole 11 and communicates a signal representative of such movement to processor 28. The logging speed is altered in accordance with speedup or slowdown signals that may be communicated from the downhole processor, or provided by the surface processor, as discussed below. This is done by altering the rotation speed of the drum 24. Offsite communication may be provided, for example by a satellite link, by the telemetry unit 36.

[0017] While running different logging instruments in a single wireline run, the present invention may use a configuration disclosed in U.S. Patent Application Ser. No. 10/780167 of *Frost* et al. filed on February 17, 2004. The teachings of *Frost* recognize the fact that different logging instruments operate best at different standoffs from the borehole wall.

[0018] Referring next to **Fig. 2**, there is shown a rig **10** on the surface that is positioned over a subterranean formation of interest. The rig **10** can be a part of a land or offshore a well production/construction facility. A borehole formed below the rig **10** includes a cased portion **42** and an open hole portion **11**. In certain instances (e.g., during drilling, completion, work-over, etc.), a logging operation is conducted to collect information relating to the formation and the borehole. Typically, a tool system **100** is conveyed downhole via a wireline **20** to measure one or more parameters of interest relating to the borehole and/or the formation **13**. The term “wireline” as used hereinafter includes a cable, a wireline, as well as a slickline. The tool system **100** can include an instrument suite comprising one or more modules **102 a,b**, each of which has a tool or a plurality of tools **104 a,b**, adapted to perform one or more downhole tasks. The term “module” should be understood to be a device such as a sonde or sub that is suited to enclose, house, or otherwise support a device that is to be deployed into a borehole. While two proximally positioned modules **102 a,b** and two associated tools **104 a,b**, are shown, it should be understood that a greater or fewer number may be used.

[0019] In one embodiment, the tool **104a** is a formation evaluation sensor adapted to measure one or more parameters of interest relating to the formation or borehole. It should be understood that the term formation evaluation sensor encompasses measurement devices, sensors, and other like devices that, actively or passively, collect data about the various characteristics of the formation, directional sensors for providing information about the tool orientation and direction of movement, formation testing sensors for providing information about the characteristics of the reservoir fluid and for evaluating the reservoir conditions. The formation evaluation sensors may include resistivity sensors for determining the formation resistivity, dielectric constant and the presence or absence of hydrocarbons, acoustic sensors for determining the acoustic porosity of the formation and the bed boundary in formation, nuclear sensors for determining the formation density, nuclear porosity and certain rock characteristics, nuclear magnetic resonance sensors for determining the porosity and other petrophysical characteristics of the formation. The direction and position sensors preferably include a combination of one or more accelerometers and one or more gyroscopes or magnetometers. The accelerometers preferably provide measurements along

three axes. The formation testing sensors collect formation fluid samples and determine the properties of the formation fluid, which include physical properties and chemical properties. Pressure measurements of the formation provide information about the reservoir characteristics.

5

[0020] The tool system **100** can include telemetry equipment **150**, a local or downhole controller **152** and a downhole power supply **154**. The telemetry equipment **150** provides two-way communication for exchanging data signals between a surface controller **112** and the tool system **100** as well as for transmitting control signals from the surface processor **112** to the tool system **100**.

10

[0021] In an exemplary arrangement, and not by way of limitation, a first module **102a** includes a tool **104a** configured to measure a first parameter of interest and a second module **102b** includes a tool **104b** that is configured to measure a second parameter of interest that is either the same as or different from the first parameter of interest. In order to execute their assigned tasks, tools **104a** and **104b** may need to be in different positions. The positions can be with reference to an object such as a borehole, borehole wall, and/or other proximally positioned tooling. Also, the term “position” is meant to encompass a radial position, inclination, and azimuthal orientation. Merely for convenience, the longitudinal axis of the borehole (“borehole axis”) will be used as a reference axis to describe the relative radial positioning of the tools **104a,b**. Other objects or points can also be used as a reference frame against which movement or position can be described. Moreover, in certain instances, the tasks of the tools **104a,b** can change during a borehole-related operation. Generally speaking, tool **104a** can be adapted to execute a selected task based on one or more selected factors. These factors can include, but not limited to, depth, time, changes in formation characteristics, and the changes in tasks of other tools.

15

20

25

[0022] Modules **102a** and **102b** may each be provided with positioning devices **140a, 140b**, respectively. The positioning device **140** is configured to maintain a module **102** at a selected radial position relative to a reference position (e.g., borehole axis). The position device **140** also adjusts the radial position of module **102** upon receiving a surface command signal and/or automatically in a closed-

30

loop type manner. This selected radial position is maintained or adjusted independently of the radial position(s) of an adjacent downhole device (e.g., measurement tools, sonde, module, sub, or other like equipment). An articulated member, such a flexible joint 156 which couples the module 102 to the tool system 100 provides a degree of bending or pivoting to accommodate the radial positioning differences between adjacent modules and/or other equipment (for example a processor sonde or other equipment). In other embodiments, one or more of the positioning devices has fixed positioning members.

10 [0023] The positioning device 140 may include a body 142 having a plurality of positioning members 144 (a,b,c) circumferentially disposed in a space-apart relation around the body 142. The members 144 (a,b,c) are adapted to independently move between an extended position and a retracted position. The extended position can be either a fixed distance or an adjustable distance. Suitable positioning members 144 (a,b,c) include ribs, pads, pistons, cams, inflatable bladders or other devices adapted to engage a surface such as a borehole wall or casing interior. In certain embodiments, the positioning members 144 (a,b,c) can be configured to temporarily lock or anchor the tool in a fixed position relative to the borehole and/or allow the tool to move along the borehole.

20 [0024] Drive assemblies 146 (a,b,c) are used to move the members 144 (a,b,c). Exemplary embodiments of drive assemblies 146 (a,b,c) include an electro-mechanical system (e.g., an electric motor coupled to a mechanical linkage), a hydraulically-driven system (e.g., a piston-cylinder arrangement fed with pressurized fluid), or other suitable system for moving the members 144 (a,b,c) between the extended and retracted positions. The drive assemblies 146 (a,b,c) and the members 144 (a,b,c) can be configured to provide a fixed or adjustable amount of force against the borehole wall. For instance, in a positioning mode, actuation of the drive assemblies 146 (a,b,c) can position the tool in a selected radial alignment or position. The force applied to the borehole wall, however, is not so great as to prevent the tool from being moved along the borehole. In a locking mode, actuation of the drive assembly 146 (a,b,c) can produce a sufficiently high frictional force between the members 144 (a,b,c) and the borehole wall as to prevent substantial relative movement. In certain

embodiments, a biasing member (not shown) can be used to maintain the positioning members **144 (a,b,c)** in a pre-determined reference position. In one exemplary configuration, the biasing member (not shown) maintains the positioning member **144 (a,b,c)** in the extended position, which would provide centralized positioning for the module. In this configuration, energizing the drive assembly overcomes the biasing force of the biasing member and moves one or more of the positioning members into a specified radial position, which would provide decentralized positioning for the module. In another exemplary configuration, the biasing member can maintain the positioning members in a retracted state within the housing of the positioning device. It will be seen that such an arrangement will reduce the cross sectional profile of the module and, for example, lower the risk that the module gets stuck in a restriction in the borehole.

[0025] The positioning device **140** and drive assembly **146 (a,b,c)** can be energized by a downhole power supply (e.g., a battery or closed-loop hydraulic fluid supply) or a surface power source that transmits an energy stream (e.g., electricity or pressurized fluid) via a suitable conduit, such as the umbilical **120**. Further, while one drive assembly (e.g., drive assembly **146 a**) is shown paired with one positioning member **144** (e.g., position member **144 a**), other embodiments can use one drive assembly to move two or more positioning members.

[0026] Referring now to **Fig. 4** there is shown an exemplary formation evaluation tool system **200** disposed in an open hole section **11**. The tool system **200** includes a plurality of modules or subs for measuring parameters of interest. An exemplary module **202** is shown coupled to an upper tool section **204** and a lower tool section **206** by a flexible member **156**. In one exemplary embodiment, the module **202** supports an NMR tool **208**. As discussed in US Patent 6,525,535 to *Reiderman et al.*, depending upon the size of the borehole, the NMR tool may be operated in either a centralized manner or in an eccentric manner. In the open hole **18**, the acoustic tool **208** may be set in a decentralized position (*i.e.*, radially eccentric position) by actuating the positioning members **140a** and **140b**. This decentralized or radially offset position is substantially independent of the radial positions of the downhole device (e.g., measurement devices and sensors) along or

in the upper/lower tool string section **204** and **206**. That is, the upper or tool string section **204** and **206** can have formation evaluation sensors and measurement devices that are in a radial position that is different from that of the module **202**. In this decentralized or radially offset position, the NMR tool can be used to gather data in large diameter boreholes. In a small diameter borehole, the NMR tool may be operated in a central position of the borehole. It should be appreciated that such motion can be accomplished by sequentially varying the distance of extension/retraction of the positioning members.

[0027] Referring next to **Fig. 5**, a flow chart generally illustrating the method of the present invention is shown. The downhole tool system is operating at an initial logging speed **301**. The initial logging speed may be determined based on prior knowledge of the expected geologic formations and fluids. Measurements are made with a plurality of formation evaluation sensors. To simplify the illustration, only two such FE sensors depicted by **303** and **305** are shown. In actual practice, there may be more than two FE sensors in the logging system. As will be discussed later, the signals measured by the sensor **305** are analyzed by a processor, preferably the downhole processor, to see if the data quality are good enough to permit a speedup **323** of logging. The processing may also be done by a surface processor, or by both a surface processor and a downhole processor. Similarly, the signals measured by sensor **303** are analyzed by a processor to see if the data quality are good enough to permit a speedup **333** of logging. The specific nature of the check is discussed below with reference to individual sensor types. Similarly, the measurements of sensor **303** are checked to see if a speedup is warranted **333**. If all the sensors provide a speedup signal **329**, a speedup signal is provided **321**. Not shown in **Fig. 4** is a check to make sure that all the speedup signals are valid. Possible situations in which a speedup signal may not be valid are discussed below.

[0028] Checks are also made to see if the sensor **305** would require a slower logging speed **327** with a similar check to see if the sensor **303** would require a slower logging speed **335**. The specific nature of the check for slower logging speed is discussed later. If at least one of the sensors provide a valid slowdown signal **337**, then logging is slowed down **331**. It should further be noted that the

order of performing the slowdown and speedup evaluation in **Fig. 4** is for illustrative purposes only, and the evaluation could be performed in the opposite order. An important feature of the invention is summarized in the following test:

1. If all the sensors provide a valid speedup signal, then logging speed is increased;
2. If one or more of the sensors provide a valid slowdown signal, then logging speed is decreased.; and
3. If neither (1) nor (2) occurs, the logging speed is maintained.

[0029] The decision as to whether to speed up or slow down the logging may be based on a comparison measurements made over several time intervals. With the natural gamma ray tool, a typical sampling rate is 10 ms. With a logging speed of 1200 ft/hr, 100 samples are obtained every second, which corresponds to a distance of four inches. If the average and/or the variance of measurements over say 1 second is substantially the same as the average of measurements over 2 seconds, it is an indication that logging speed may be increased without loss of resolution or loss of precision. With the HDIL tool, for example, transmitter and receiver coils are configured to operate with different depths of investigation by operating at several frequencies and/or by using data from several transmitter-receiver spacings. There is a high degree of redundancy in the data. Again, by comparing averages over different time intervals, an indication can be obtained as to whether logging speed may be increased, or, conversely, whether logging speed should be decreased.

[0030] With nuclear sensors such as used for neutron porosity or gamma ray density logs, the count rates are subject to statistical fluctuations. This is due to the fact that over short time intervals, the source emits radiation that may fluctuate, and furthermore, the interaction of the source radiation with nuclei in the formation is also governed by statistical processes. In order to make a meaningful determination of porosity and/or density, it becomes important to make sure that the actual number of accumulated counts has a minimum value for all the detectors used in making the nuclear measurements.

[0031] Another point to note with respect to nuclear sensors is that some compensation is applied to account for offset of the detectors from the borehole wall. For example, if ρ_{ss} and ρ_{ls} are measurements made by short spaced (SS) and long spaced (LS) sensors, a density correction is applied to give a corrected density according to the relation:

$$\Delta\rho = \rho - \rho_{LS} = f(\rho_{LS} - \rho_{SS}) \quad (1)$$

This is called the “spine and rib” correction. In situations where there are washouts, is possible that the individual sensor measurements may pass the tests described above regarding the count rate and the statistical fluctuations.

Nevertheless, a corrected density measurements may still be invalid due to the large washout. This is an example of the requirement that the speedup or slowdown indicator (discussed above) be a valid one.

[0032] An acoustic sensor may also be part of the instrument suite. This is generally used at least for measurements of compressional (P- wave) velocities of earth formations. To make measurements of P-wave velocities, the transmitter(s) and receivers that comprise the acoustic sensor are operated in a monopole mode. Energy generated by the transmitter travels through the formation as a refracted P-wave and from traveltime measurements at the array of receivers, the P-wave velocity can be determined. The semblance of the received signal is an indication of the quality of the data, and if the semblance is sufficiently high, then it is possible to increase the logging speed without detriment. It should be noted that if the formation shear wave (S- wave) velocity is greater than the velocity of sound in the drilling mud, it is possible to determine formation S- velocities using a monopole excitation.

[0033] The acoustic tool may also be operated in a dipole mode in which shear waves (S-waves) are excited in the formation. Again, the semblance of the received signals may be used as an indicator for possible speedup of logging speed. It should be noted that acoustic measurements take several milliseconds to make, compared to the few microseconds needed for nuclear and resistivity measurements. The acoustic tool may also be operated in the so-called cross-dipole mode wherein the transmitter is activated in a first dipole mode and then

activated in a second dipole mode orthogonal to the first dipole mode. The cross-dipole mode is useful in determining azimuthal anisotropy in the earth formation, an indication of possible fracturing. It should be clear that with respect to the acoustic tool, the speedup or slowdown indicator is based on all of the modes of acquisition that are desired.

[0034] For logging in laminated reservoirs (that have transverse isotropy in both resistivity and acoustic properties), a multicomponent resistivity sensor may be included in the instrument suite. Service with such a sensor is provided by Baker Hughes Incorporated under the mark 3DEXSM and a tool suitable for the purpose is disclosed in US Patent 6,147,496 to *Strack* et al. Using such a device, it is possible to determine resistivity anisotropy in the earth formation that is a better indication of reservoir quality than the HDIL measurements (that are sensitive only to horizontal resistivity). In anisotropic reservoirs, it may also be desirable to operate the acoustic sensor in the dipole mode. The natural gamma ray sensors do not necessarily have the resolution to be able to identify laminations at the scale at which resistivity and/or acoustic anisotropy may occur. Consequently, it may be desirable to include a high resolution resistivity sensor, such as a microlaterolog, as part of the instrument suite. Signals from such a sensor could be used to start acquisition with the 3DEX device and/or to switch the acoustic sensor to joint monopole/dipole operation.

[0035] As would be known to those versed in the art, wireline logging operations are typically conducted with the instrument suite being pulled up the borehole. This is preferable to logging with the instrument suite being lowered into the borehole since in the latter situation, there may be sticking of the instrument suite into the borehole with the result that the logging depth as determined at the surface location may not correspond to the actual depth of the instruments. With the variations in logging speed that are possible during practice of the present invention, due to the elasticity of the wireline, there may be "yo-yoing" of the instrument suite at the bottom of the wireline. US Patents 6,154,704 and 6,256,587 to *Jericevic* et al., having the same assignee as the present application and the contents of which are fully incorporated herein by reference, present methods for correcting the measurements for the effects of the yo-yoing. In the

context of the present invention, this correction may be made after the logging operations are conducted on the stored data at the surface. Alternatively, a correction may be applied downhole prior to any determination to speed up or slow down logging speed.

5

[0036] The present invention has been described in the context of a wireline device. The method of the present invention is equally applicable on slickline conveyed device wherein a downhole processor is used for providing a signal to speed up or slow down the speed. The slickline may optionally be conveyed inside a drilling tubular. The FE sensor measurements are stored in a downhole memory for subsequent retrieval.

10

[0037] While the foregoing disclosure is directed to the preferred embodiments of the invention, various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope of the appended claims be embraced by the foregoing disclosure.

15

CLAIMS

What is claimed is:

- 1 1. A method of conducting logging operations of a borehole in an earth
2 formation, the method comprising:
3 (a) conveying a plurality of formation evaluation (FE) sensors on a
4 conveyance device into said borehole;
5 (b) using said conveyance device to move said plurality of FE sensors
6 at a logging speed while making measurements with said FE
7 sensors;
8 (c) analyzing said measurements made by said FE sensors; and
9 (d) altering said logging speed based on said analysis.
10
- 1 2. The method of claim 1 wherein said FE sensors are selected from the
2 group consisting of (i) a resistivity sensor, (ii) a natural gamma ray sensor,
3 (iii) a porosity sensor, (iv) a density sensor, (v) a nuclear magnetic
4 resonance sensor, and, (vi) an acoustic sensor.
5
- 1 3. The method of claim 1 wherein said conveyance device comprises a
2 slickline.
3
- 1 4. The method of claim 1 wherein said conveyance device comprises a
2 wireline.
3
- 1 5. The method of claim 4 further comprising positioning one of said
2 plurality of sensors at a different distance from a center of said borehole
3 from another one of said plurality of sensors.
4
- 1 6. The method of claim 1 wherein said alteration comprises an increase in
2 said logging speed.
3
- 1 7. The method of claim 1 wherein said alteration comprises a decrease in said
2 logging speed.
3

- 1 8. The method of claim 6 wherein said altering further comprises:
2 (i) analyzing measurements made by each of said plurality of FE
3 sensors for validity, and
4 (ii) determining if measurements made by each of said FE sensors
5 would be of acceptable quality at an increased logging speed.
6
- 1 9. The method of claim 7 wherein said altering further comprises:
2 (i) analyzing measurements made by at least one of said plurality of
3 FE sensors for validity, and
4 (ii) determining if measurements made by said at least one of said
5 plurality of FE sensors is of unacceptable quality at said logging
6 speed.
7
- 1 10. The method of claim 1 wherein (c) and (d) are carried out using a
2 downhole processor.
3
- 1 11. The method of claim 1 wherein (c) and (d) are carried out using a surface
2 processor
3
- 1 12. The method of claim 1 wherein one of said FE sensor comprises a
2 microresistivity sensor, the method further comprising providing a signal
3 based on a measurement made by said microresistivity sensor to activate at
4 least one of (i) a multicomponent resistivity sensor, and, (ii) an acoustic
5 sensor in a dipole mode.
6
- 1 13. The method of claim 1 further comprising correcting measurements
2 made by at least one of said FE sensors following said alteration of said
3 logging speed to correct for "yo-yoing" of said conveyance device.
4
- 1 14. An apparatus for conducting logging operations of a borehole in an earth
2 formation, the apparatus comprising:
3 (a) a plurality of formation evaluation (FE) sensors;
4 (b) a conveyance device which moves said plurality of FE sensors at a
5 logging speed while making measurements with said FE sensors;

- 6 (c) a processor which analyzes said measurements made by said FE
7 sensors; and
8 (d) a processor which alters said logging speed based on said
9 analysis.
10
- 1 15. The apparatus of claim 14 wherein at least one of said processors in (c)
2 and (d) is at a downhole location.
3
- 1 16. The apparatus of claim 15 wherein said at least one processor includes a
2 memory for storing said measurements.
3
- 1 17. The apparatus of claim 14 wherein said FE sensors are selected from the
2 group consisting of (i) a resistivity sensor, (ii) a natural gamma ray sensor,
3 (iii) a porosity sensor, (iv) a density sensor, (v) a nuclear magnetic
4 resonance sensor, and, (vi) an acoustic sensor.
5
- 1 18. The apparatus of claim 14 wherein said conveyance device comprises a
2 slickline.
3
- 1 19. The apparatus of claim 14 wherein said conveyance device comprises a
2 wireline.
3
- 1 20. The apparatus of claim 19 further comprising a device which positions one
2 of said plurality of sensors at a different distance from a center of said
3 borehole from another one of said plurality of sensors.
4
- 1 21. The apparatus of claim 14 wherein said alteration comprises an increase in
2 said logging speed.
3
- 1 22. The apparatus of claim 14 wherein said alteration comprises a decrease in
2 said logging speed.
3
- 1 23. The apparatus of claim 22 wherein:

- 2 (i) said processor in (c) analyzes measurements made by each of
3 said plurality of FE sensors for validity, and
4 (ii) said processor in (d) determines if measurements made by
5 each of said FE sensors would be of acceptable quality at an
6 increased logging speed.
7
- 1 24. The apparatus of claim 22 wherein:
2 (i) said processor in (c) analyzes measurements made by at least
3 one of said plurality of FE sensors for validity, and
4 (ii) said processor in (d) determines if measurements made by
5 said at least one of said plurality of FE sensors is of unacceptable
6 quality at said logging speed.
7
- 1 25. The apparatus of claim 14 wherein said processor in (c) and said
2 processor in (d) comprise a downhole processor.
3
- 4 26. The apparatus of claim 14 wherein said processor in (c) and said
5 processor in (d) comprise a surface processor.
6
- 7 27. The apparatus of claim 14 wherein said alteration further comprises
8 controlling a spooling for controlling the speed of said conveyance device.

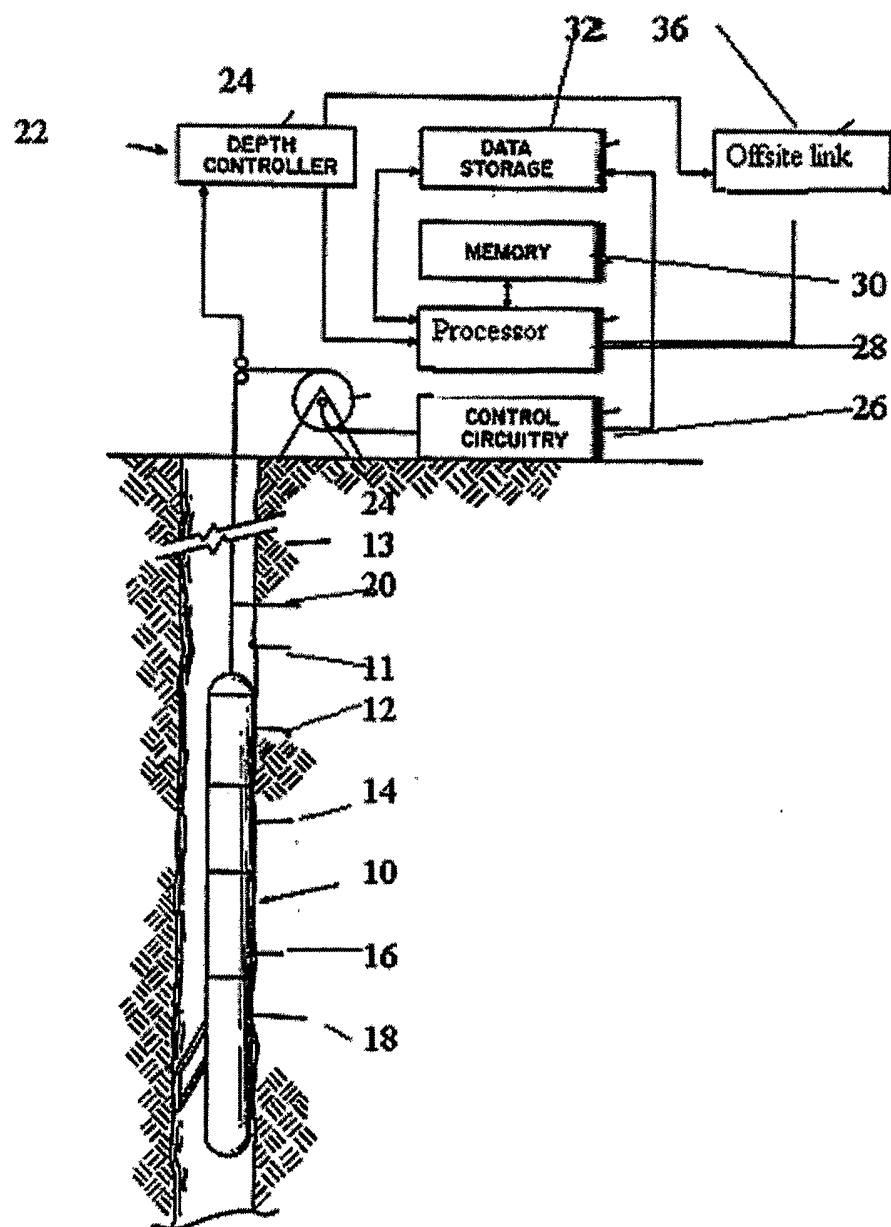


Figure 1

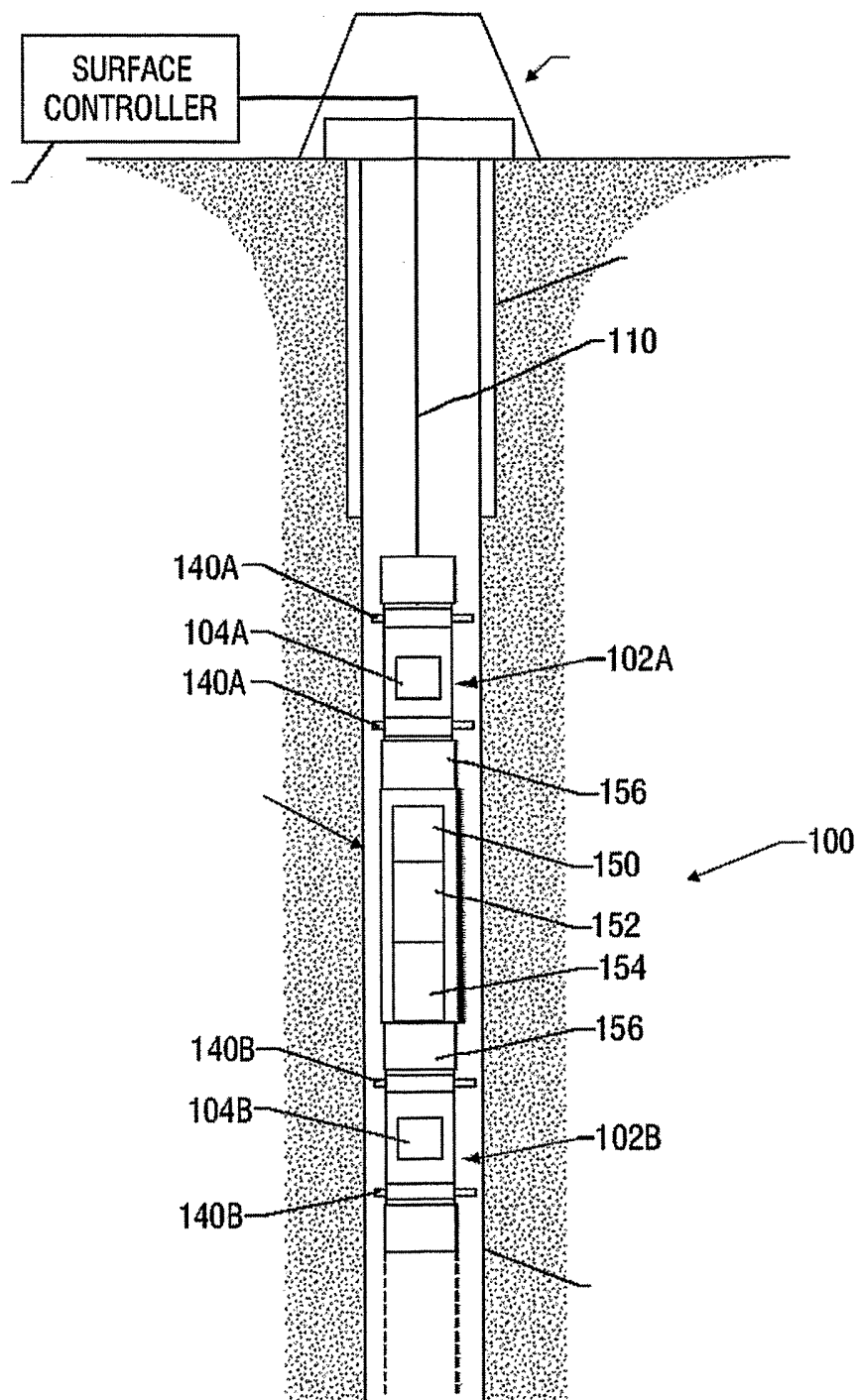


Figure 2 (prior art)

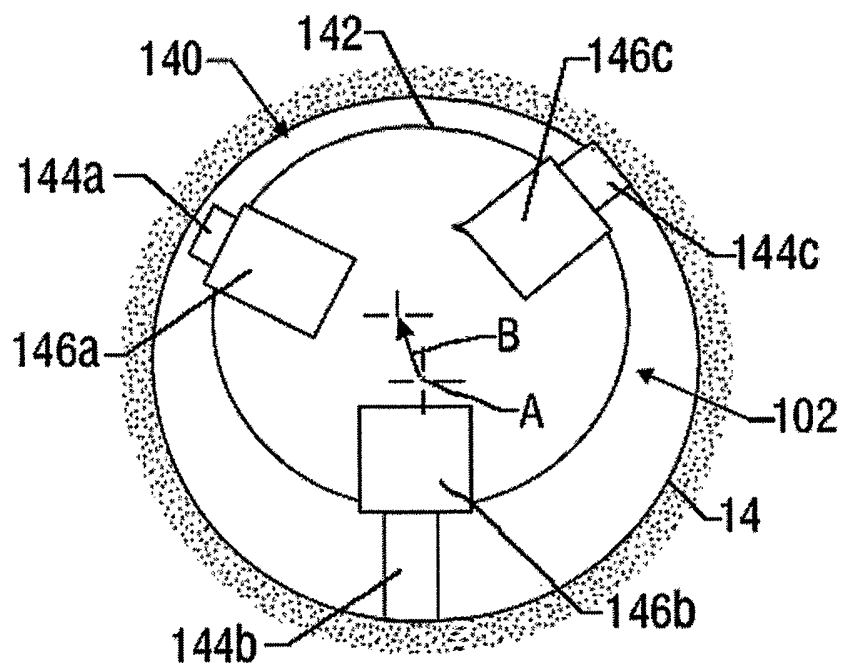


Figure 3 (prior art)

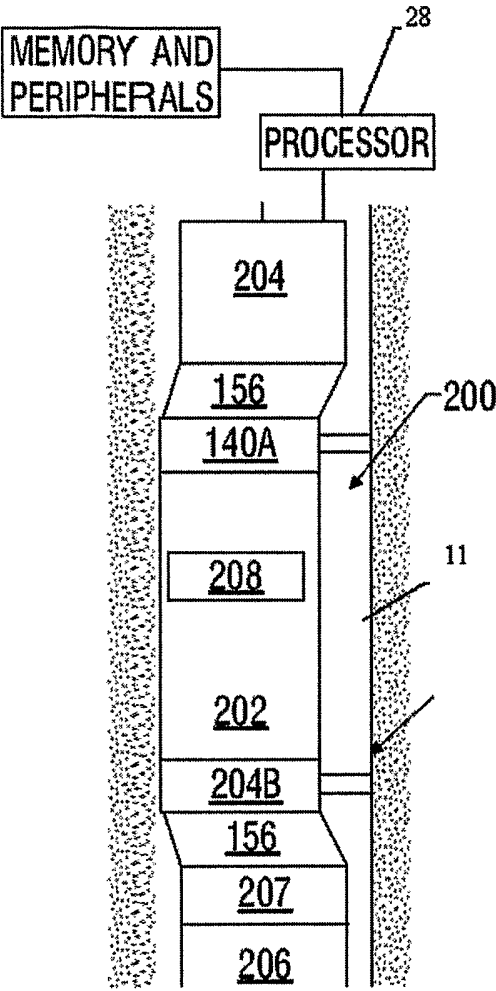


Figure 4 (prior art)

Figure 5

